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Prepared for:

Energy Networks Association on behalf of

Smart Grids Forum – Work Stream 3

Assessing the Impact of Low Carbon Technologies on Great Britain's Power Distribution Networks

Version: 3.1

31st July 2012

Report No: 82530

Smart Grids Forum –WS3

Assessing the Impact of Low Carbon Technologies on Great Britain's Power Distribution Networks

Project No: 82530

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Partners and Acknowledgements

This report has been produced by EA Technology, using input from our project partners:

- Element Energy
- GL Noble Denton
- Frontier Economics
- Chiltern Power

The project has taken input from a range of sources, but particular recognition goes to Elexon for providing material on demand profiles, WS3 steering group members and the Network Operator project steering group:

- Energy Networks Association
- Electricity North West Limited
- UK Power Networks
- Northern Powergrid
- ScottishPower
- Western Power Distribution
- Scottish & Southern Energy
- National Grid
- Inexus

Executive summary

Britain's electricity system is facing a period of significant uncertainty as the national transition is made to a low carbon economy. Policy signals from Government are driving for new lower carbon power and heating sources and more efficient uses of electricity. Low carbon generation in the form of photovoltaic (PV) cells, onshore wind and biomass plants, and new types of loads such as electric vehicles (EVs) and heat pumps (HPs), will create disruptive changes for the conventional electricity network.

The spread of these new technologies on networks will not be uniform and will pose different challenges to different network types, such as in rural and urban contexts. To address this in an effective and cost-efficient way, a range of solutions will be required comprising a mix of new and conventional technologies. Decisions will need to be taken regarding the optimal investment strategy to ensure that the needs of customers are met while not compromising the quality of supply and security of power distribution.

This report describes a comprehensive new model that has been developed to assist the evaluation of investment options to address the challenging network issues that lie ahead. A summary of the key findings is provided below.

Key Observations

Observation - technology uptake. Market forces and the effect of incentives, will drive the spread and speed of deployment of low carbon technologies across the country. This is likely to result in an irregular deployment of technologies throughout Great Britain, creating local clustering particularly in the early years of uptake, as a result of both locational suitability and consumer appetite.

Observation - network variability. The electricity networks of GB are similarly not uniform. A network feeding a dense central business district is fundamentally different from one feeding a more dispersed collection of rural farmsteads, this being due to a combination of factors including load type, load density and the physical construction of the infrastructure. The capacity (or headroom) available on existing networks to accommodate new low carbon technologies therefore differs across the country.

Observation - technology options. New solutions to address network constraints are coming to fruition. The transition to the so-called 'smart grid' is essentially a term to describe the integration of conventional and innovative solutions to accommodate the low carbon challenge, utilising solutions with customers, network equipment and generators. Whilst this presents significant opportunity, the choice of solutions available to a network operator can be expected to increase substantially as the innovation learning curve takes effect. Knowing which solutions to use, when, and on which type of network will be essential to assess investment needs and ensure that electricity networks continue to operate in an efficient manner, are capable of responding to continuing change, and deliver value to consumers.

Key Conclusions

This project was launched to help to quantify the results of the Phase 1 report developed under the GB Smart Grids Forum Workstream three (WS3)[1]. It builds upon scenario information developed by DECC under WS1 and an initial modelling platform developed through Ofgem under WS2. The key conclusions of the WS3 Phase 1 report form the titles in bold below.

The Potential impact of future GB energy scenarios on power networks is material

Significant investment requirements. The DECC and DfT scenarios developed under WS1 of different Low Carbon Technology (EVs, HPs, PV and Distributed Generation (DG)) uptake have been applied in the WS3 model. The model has been developed to always ensure the network accommodates these external factors, through the use of an appropriate set of solutions.

For each scenario, investment on the distribution network has been shown to be significant. The spread of investment between the very highest and the very lowest combination of scenarios and investment strategies is shown in the figure below.

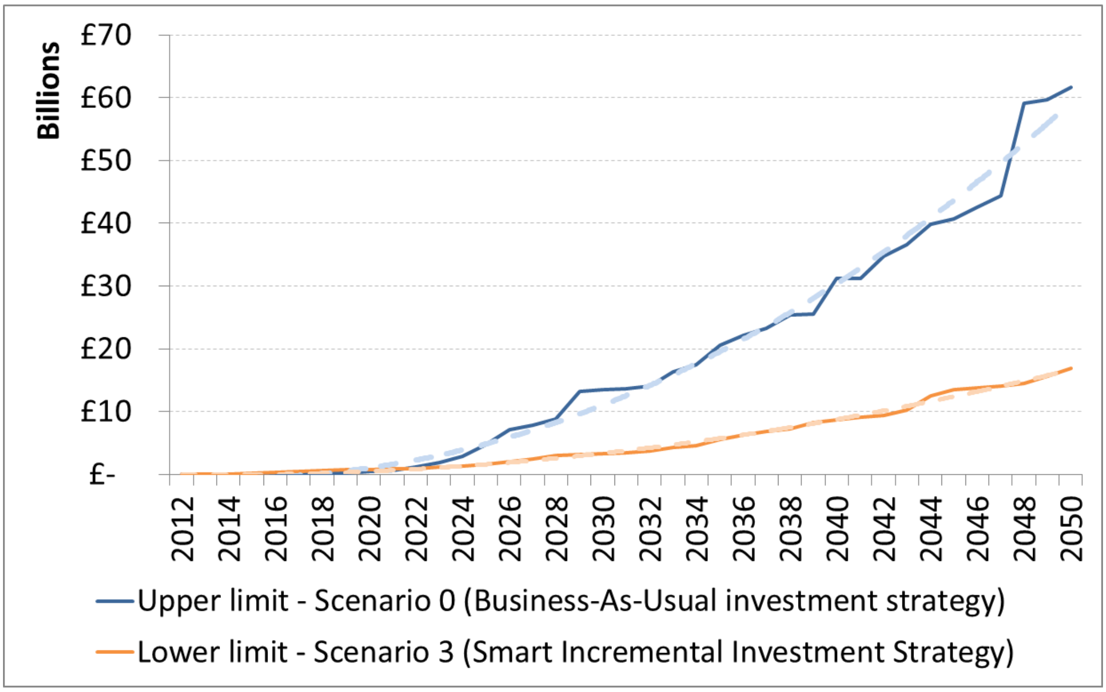


Figure 0.1 Spread of GB network related investment (non-discounted cumulative totex showing the two most extreme scenarios) to accommodate projections in Low Carbon Technologies connecting to the electricity distribution network

The results show that the assumptions behind load growth and energy efficiency tend to cancel each other out, with negligible investment triggered when the LCT profiles are fixed at 2012 levels. This should not be mistaken for an assumption that national load related expenditure would drop off, as this model has no understanding of local effects such as load churn (or the connection of large loads

[1]The WS3 Phase 1 report is available here: http://www.ofgem.gov.uk/Networks/SGF/Publications/Documents1/Smart%20Grid%20Forum%20Workstream%203%20Report%20071011%20MASTER.pdf

or generation in specific parts of the network. The outputs of this model would therefore be expected to sit alongside (and not in place of) asset replacement and load related expenditure forecasts.

Scenarios help address uncertainty. A scenario is not a forecast. The scenarios described in this report are based on those developed by DECC and DfT for the UK to meet its carbon reduction targets. It is not envisaged that the reality will exactly follow any one of these scenarios; rather they are presented as plausible paths that could be taken and it is the differences between the scenarios that is as important as the scenarios themselves. Some of the LCT scenarios stop at 2030, and these have required extrapolation to present a view as to how they could continue to 2050. Furthermore, the modelling provides for regional views that determine how the scenarios might vary in terms of where penetrations of certain LCTs will be higher or lower across GB.

The challenge ahead is technically demanding and of a scale not seen in 50 years

Investment will require step changes. For all scenarios, investment in the RIIO-ED1 period is relatively low, but is shown to rapidly increase into RIIO-ED2 and beyond. This change is highlighting that there is capacity in today's networks, for modest levels of LCTs, but as the volume of LCTs increases, networks struggle to accommodate this, triggering investment as headroom becomes depleted.

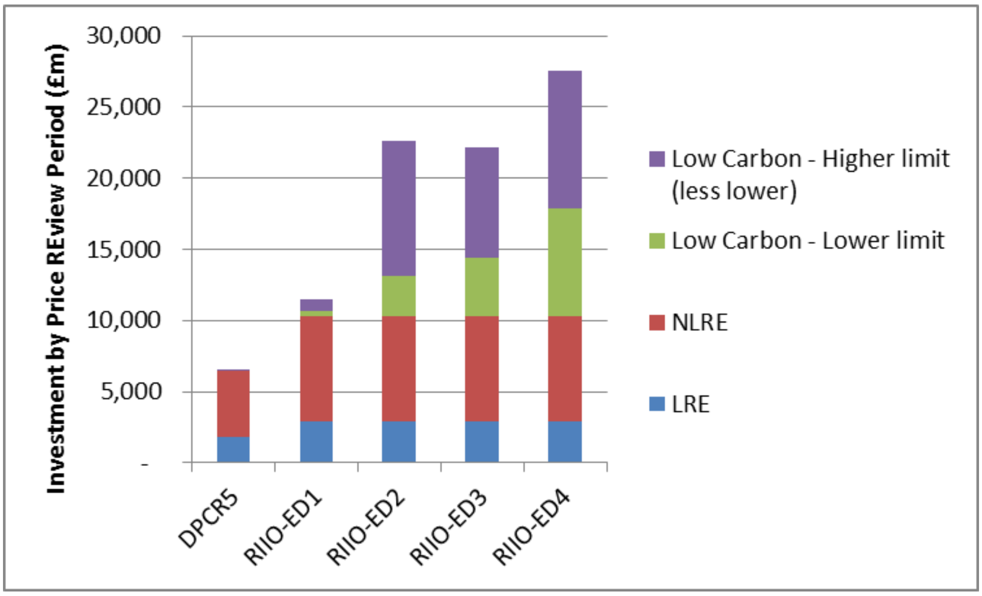


Figure 0.2 Gross GB network related investment for the next four RIIO periods[2]

According to the projections for Low Carbon related investment from this model, the rapid ramp up in RIIO-ED2 is likely to pose a significant challenge to DNOs. As even at the lower end of the investment scenario projections, the Low Carbon related costs is roughly equal to the annual LRE in

2 **Load related expenditure** (LRE) – investment driven by changes in demand, i.e. that in response to new loads or generation being connected to parts of the network (connections expenditure) and investment associated with general reinforcement. LRE was £1.8bn in DPCR5. **Non-load related expenditure** (NLRE) – other network investment that is disassociated with load. The dominant area of investment in this category is asset replacement (76% of the NLRE for DPCR5). NLRE was £4.6bn for DPCR5. **LRE and NLRE** have been simply scaled by 8yrs/5yrs to correlate to the longer Price Control Periods for RIIO in this illustration.

DPCR5 and could, at worst case, exceed NLRE in the ED2 period. The investment profile then remains broadly static through ED3, increasing again in ED4 (although it is noted that the results this far out are subject to significant uncertainty, and should be treated with caution).

Clustering is a dominant factor. The default clustering in the model has been based on the deployment pattern observed for PV under the GB Feed-in-Tariff. This level of clustering is notably high, and there is no evidence to suggest whether this would be similar for the uptake of Heat Pumps or different forms of Electric Vehicles. A lower level of clustering would give rise to different investment profiles. The model can be used to explore these sensitivities.

Innovative products and architectures (smart grids) offer cost-effective solutions

Smarter strategies appear most cost-effective. The modelling shows that a smart grid strategy of using innovative solutions in conjunction with conventional reinforcement options appears to be more cost effective than using conventional solutions alone. This is mainly because the smartgrid solutions are assumed to have a lower cost than their conventional counterparts and in many situations have advantages of being more flexible and less disruptive to implement.

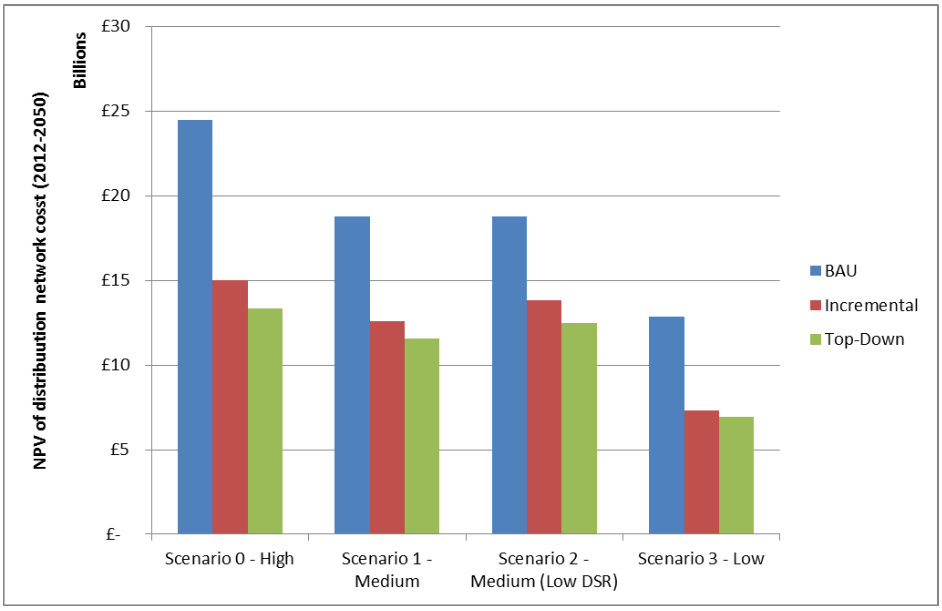


Figure 0.3 Summary of present value of gross totex of distribution network investment (2012-2050)

These results show a reduction in costs incurred before 2050 associated with applying the smartgrids investment strategy over using solely conventional solutions for all modelled scenarios. This is based on modelling results out to 2050, with the Incremental and Top-Down investment strategies consistently representing overall investment levels of the order of 50-75% of the Business-As-Usual strategy. In all scenarios, the top-down smartgrid investment strategy is proving to have a lower cost than that of incremental. Though, particularly in the case of Scenario 3, the difference is small and within the range of the model’s uncertainty.

Innovation will need to be adopted in conjunction with traditional network investment

Smart solutions alongside conventional reinforcement. 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 options to choose from when selecting solutions within these strategies

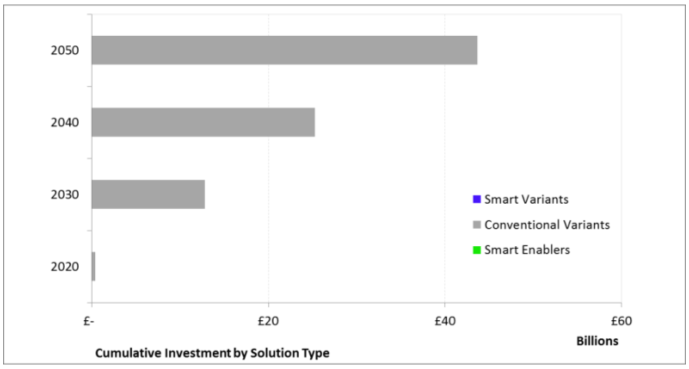


Figure 0.4 Overview of solutions selected (cumulative, undiscounted totex): Business-As-Usual (BAU) Investment strategy only (Scenario 1)

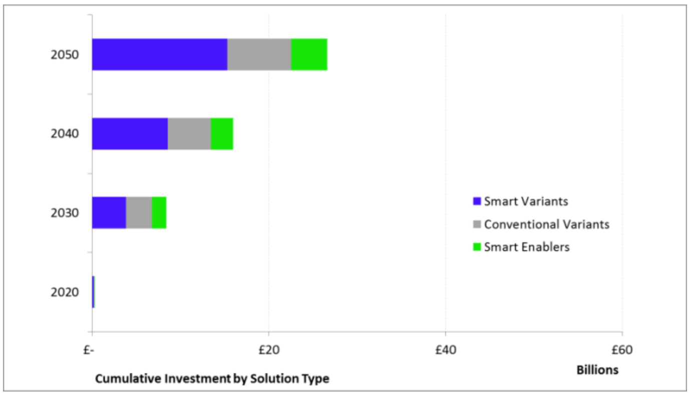


Figure 0.5 Overview of solutions selected (cumulative, undiscounted totex): Smart-Incremental Investment strategy only (Scenario 1)

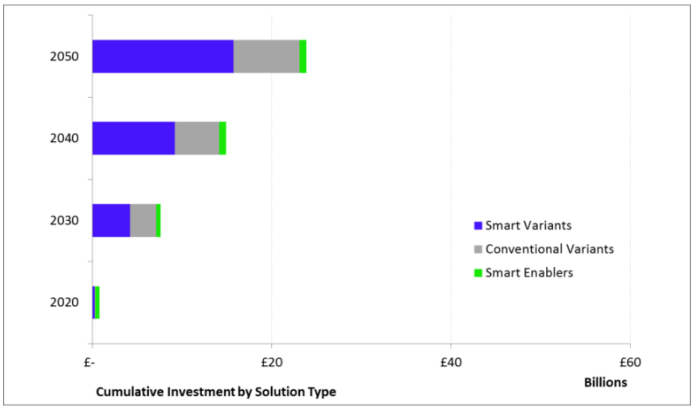


Figure 0.6 Overview of solutions selected (cumulative, undiscounted totex): Smart-Top-Down Investment strategy only (Scenario 1)

Table 0.1 Summary of investment in all solutions selected within the ED1 and ED2 periods for each investment strategy[3]

Cumulative Gross totex costs (£m)	Business-As-Usual		Smart Incremental		Smart Top-Down	
	End ED1	End ED2	End ED1	End ED2	End ED1	End ED2
	2022	2030	2022	2030	2022	2030
Active Network Management - Dynamic Network Reconfiguration	£ -	£ -	£ 103.2	£ 174.1	£ 103.2	£ 174.1
D-FACTS	£ -	£ -	£ 110.0	£ 391.6	£ 110.0	£ 449.0
DSR	£ -	£ -	£ 1.8	£ 231.1	£ 1.8	£ 231.1
Electrical Energy Storage	£ -	£ -	£ -	£ -	£ -	£ -
Embedded DC Networks	£ -	£ -	£ -	£ -	£ -	£ -
EAVC	£ -	£ -	£ 0.2	£ 1.4	£ 0.2	£ 1.4
Fault Current Limiters	£ -	£ -	£ 4.7	£ 63.2	£ 4.7	£ 63.2
Generator Constraint Management	£ -	£ -	£ -	£ -	£ -	£ -
Generator Providing Network Support e.g. Operating in PV Mode	£ -	£ -	£ -	£ -	£ -	£ -
Local smart EV charging infrastructure	£ -	£ -	£ 3.4	£ 155.4	£ 3.4	£ 155.4
New Types Of Circuit Infrastructure	£ -	£ -	£ -	£ -	£ -	£ -
Permanent Meshing of Networks	£ -	£ -	£ 5.6	£ 2,650.8	£ 5.6	£ 2,650.8
RTTR	£ -	£ -	£ 16.6	£ 145.6	£ 16.6	£ 435.1
Switched capacitors	£ -	£ -	£ -	£ -	£ -	£ -
Temporary Meshing	£ -	£ -	£ 3.6	£ 42.2	£ 3.6	£ 42.2
Split Feeder	£ 82.5	£ 6,535.1	£ 42.1	£ 800.4	£ 42.1	£ 885.7
New Split Feeder	£ -	£ 10.2	£ -	£ -	£ -	£ -
New Transformer	£ 450.0	£ 2,465.6	£ 64.7	£ 1,615.5	£ 64.7	£ 1,615.5
Minor Works	£ 186.0	£ 3,557.4	£ 79.0	£ 512.6	£ 79.0	£ 377.3
Major Works	£ 92.4	£ 232.8	£ -	£ -	£ -	£ -
Comms & Control Platforms between variant solutions	£ -	£ -	£ 3.3	£ 195.3	£ 5.0	£ 5.0
DNO to DSR aggregator enablers	£ -	£ -	£ 0.9	£ 103.9	£ 3.3	£ 3.3
Network Measurement Devices	£ -	£ -	£ 11.8	£ 390.9	£ 303.4	£ 303.4
DCC to DNO communications and platforms	£ -	£ -	£ -	£ -	£ 132.8	£ 132.8
Phase imbalance measurement	£ -	£ -	£ -	£ -	£ 43.2	£ 43.2
Weather / ambient temp data	£ -	£ -	£ 29.1	£ 917.2	£ 0.8	£ 0.8
Design tools	£ -	£ -	£ -	£ -	£ 0.5	£ 0.5
Protection and remote control	£ -	£ -	£ -	£ -	£ 31.5	£ 31.5
TOTAL (£m)	**£ 811**	**£ 12,801**	**£ 480**	**£ 8,391**	**£ 955**	**£ 7,602**

Key
Conventional Solution
Smart Solution
Smart Enabler

It is noted that the modelling in the report should be regarded as indicative-only for the selection of specific solutions. Solutions will move in their merit order as they mature and as network conditions develop. In practice, technology solutions should be adopted on their individual and local merits with individual business cases for technology investment remaining as key to decision-making and selection.

The model described in this report may be used to inform longer term technology strategies but will require careful sensitivity and tipping point analysis. The modelling has shown that incremental movement in the merit order of solutions as technologies mature is unlikely to have a significant effect on the headline conclusions.

Societal impacts could be limited with a smart grid investment strategy. The model does not consider the societal costs of disruption associated with the deployment of solutions directly in its output. It however helpful to understand the results of the model in non-financial terms, such as a comparison in the amount of overhead line or underground cable deployed, shown below.

[3] The years 2022 and 2030 are used in the table because the model works on a calendar year, rather than financial year basis, and these years most closely align with the regulatory periods under the RIIO framework

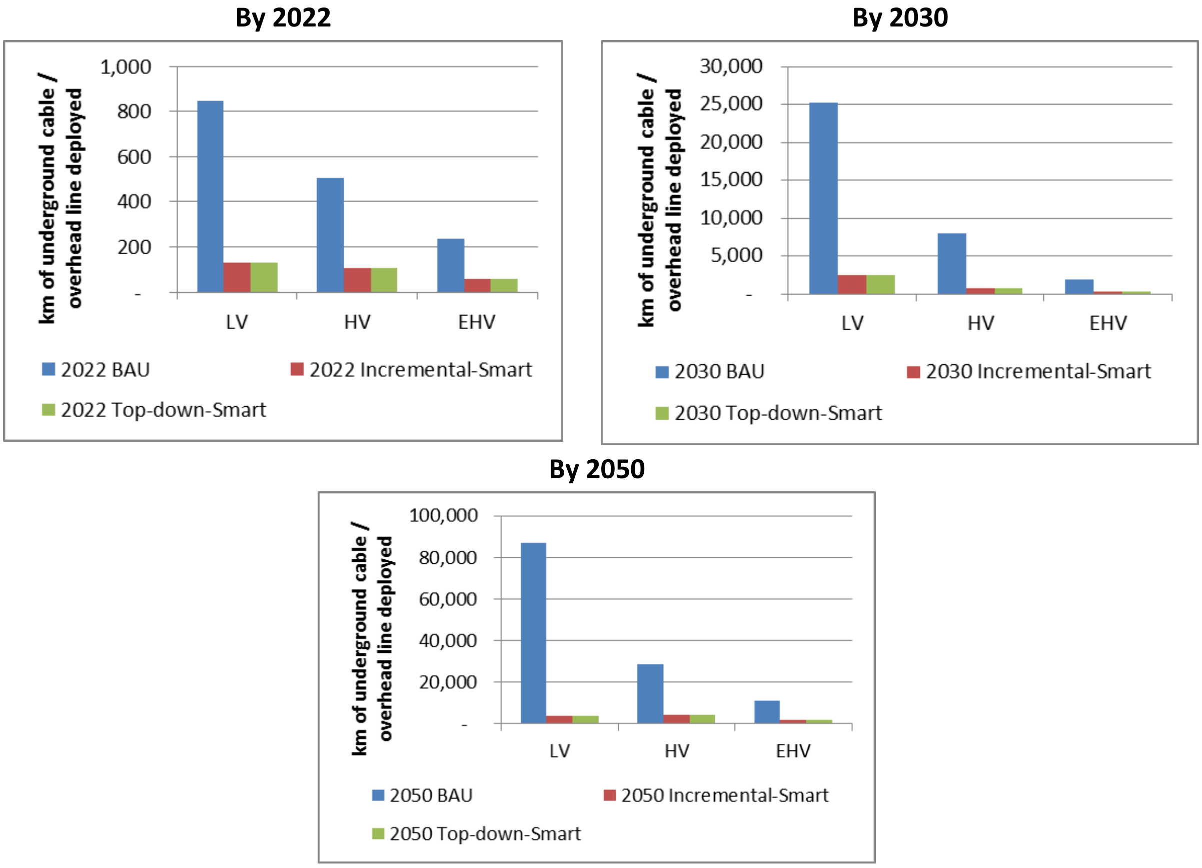


Figure 0.7 Summary showing the differences in the amount of underground cable and overhead line selected for deployment between the three investment strategies (all based on Scenario 1)

Differences between the three scenarios can clearly be seen, and are exacerbated as volumes of LCTs increase by 2030 and beyond. In the conventional (BAU) strategies, the options for investment are limited to new circuits or new transformers. It is natural that both are deployed, and at scale, as the network is put under more pressure with the increase in LCTs.

In the cases of both smart investment strategies, the model is selecting other solutions alongside conventional reinforcement. The result is a significant reduction in the amount of circuits that would need to be replaced, purely to accommodate uptake in LCTs[4].

Technology alone will not deliver the required outcomes: Commercial and Regulatory frameworks and consumer engagement will be key enablers

Solutions need to be developed with a range of stakeholders. A number of the solutions considered within the model involve the interaction of the DNO with other parties; including customers and generators. In order for these demand-side response or generator-side response solutions to become a reality, the existing regulatory framework and commercial arrangements that exist may need to be re-visited. The contracts that DNOs may have with customers who are willing to have a portion of their demand shifted to times of day when there is greater capacity within the

[4] Once again, this model treats the challenge posed by the uptake of LCT in isolation to other forms of network investment (e.g. load related or non-load related). It is recognised that some synergies may be borne of a more holistic strategy.

network will need to be established, including specific elements regarding the amount that the customer would receive for this inconvenience, the amount of time over which demand could be shifted, and the duration of the contract with the customer. All of these are at present unknown and more accurate information in these areas could be used to inform the model in future.

Further to this, it will be important that the industry as a whole is united regarding the way in which the availability and use of DSR solutions is communicated to customers.

Other solutions, such as generator side response and the use of EES devices, while not selected in any great numbers by the model at present, may also prove significant in the future as a much larger number of generators are able to offer this service and as the costs of EES solutions reduce. These will similarly require new commercial arrangements as it may well prove to be the case that DNOs are interfacing with several third parties who will be operating EES devices.

Enabling actions for the short term will accelerate advanced functionality in later years

Investment in ED1 in readiness for later years. The boundaries of investment (excluding any pre-emptive top-down investment) out to the end of the RIIO-ED2 period have been shown below.

Under the RIIO framework it is noted that Ofgem is looking to focus on long term value for money, rather than solely the 8 year price control period. Based on the input assumptions, the model is showing a bias towards the top-down smart investment strategy being optimal over the longer term. This being the case, the model implies that investment will need to be undertaken for a range of enabler technologies in the RIIO-ED1 period, in order to ensure it is available when needed (e.g. the second half of ED1 and into ED2).

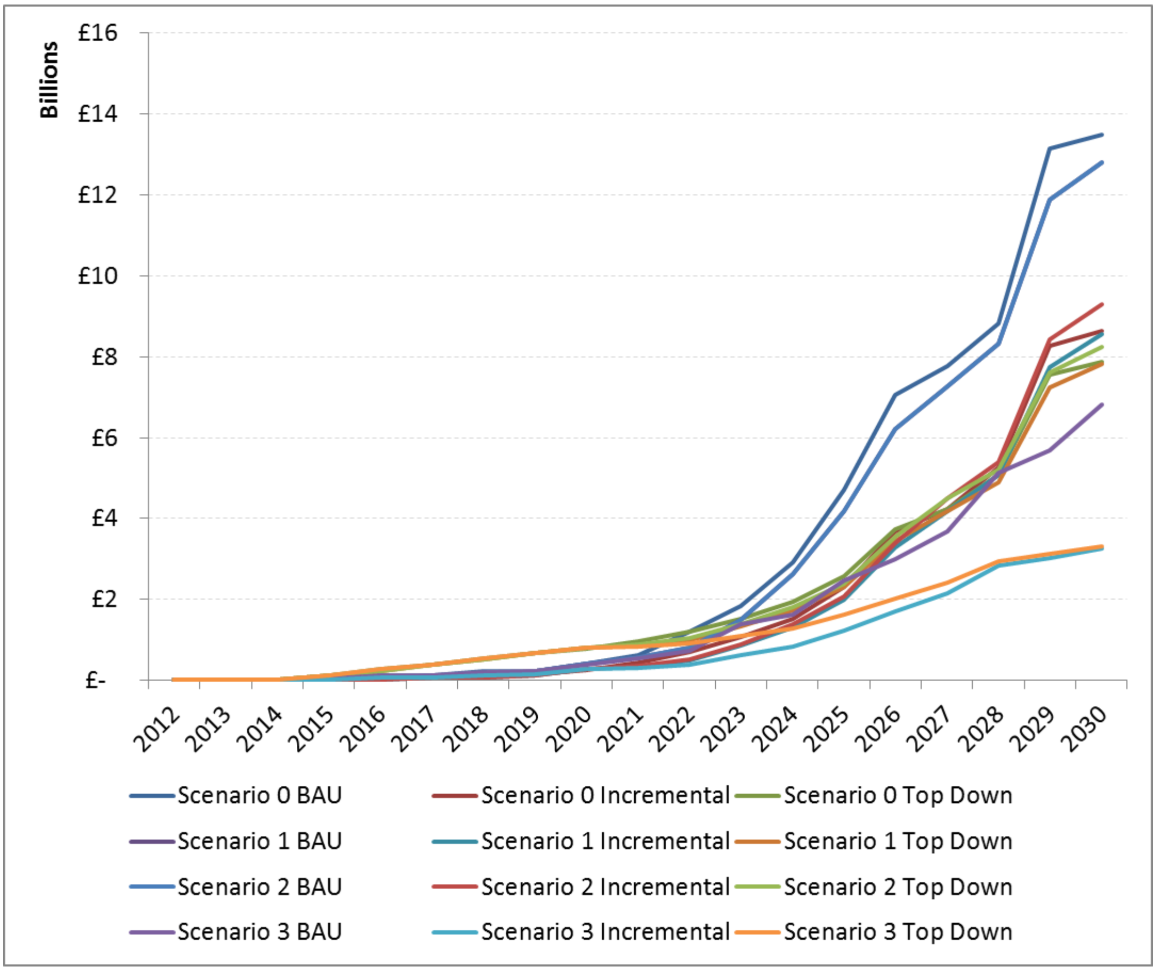


Figure 0.8 Totex investment (gross cumulative) of all scenarios until the end of RIIO-ED2 period associated with facilitating the Low Carbon Technology update

No-regrets investments for consideration in RIIO-ED1. The results from this analysis suggest a case for a top-down-smart strategy in place of an incremental-smart strategy. This indicates that investment in enabler technologies (monitoring devices, communications links, control systems) should be considered in the ED1 period for the long term interests of customers. It should be noted however, that while this has been based on best available data, this case will need to be reviewed. There is, for example, no information as yet regarding the costs or framework by which a DNO will interface with the national Smart Metering data system to obtain consumer demand and network node data.

RIIO-ED1 poses a transition period, where both incremental and top-down investment may have to be carried out side-by-side. For example, incremental deployments may be needed to provide necessary headroom in areas of networks where high clustering is taking place, at the same time as deploying enabler solutions for when larger penetrations of LCT appear.

Customers can expect attractive new services and products, including helpful energy automation to obtain the best deals and services

The importance of customer engagement. Engaging customers in DSR activities presents a significant opportunity and challenge for DNOs. At a domestic level, customers will expect to be rewarded for their involvement, and will also expect to be able to make use of the latest technology (in the form of smart appliances etc) to ensure they are getting the best deal available.

Commercial customers may well see the use of DSR as a significant opportunity to reduce energy costs within their business by changing operating practices (such as running certain processes or performing various tasks at "off peak" times). Unlike domestic customers, larger energy users may be in a position to negotiate with the DNO to ensure they obtain value for money.

There are still several outstanding questions regarding the level of access that DNOs will have to smart meter data and the level of control that they will therefore be able to exert on customers willing to engage in DSR. This report does not consider the range of options regarding the amount of data available or any costs associated with it, and once such information is available, it will be possible to update the model with these revised costs for the relevant enabling technologies.

Additional Observations – An iterative process

Evidence from innovation trials will improve the evidence base. Many of the performance and cost parameters for the solutions used in the model have been based on a strategic engineering view, based on emerging experience, rather than on evidence from proven solutions. This is inevitable given the stage of development in the sector, both here and internationally. The model (and this report), provide indicative results for solutions and the skeleton structure that can be built upon over time, as evidence from projects both in GB and internationally comes to light.

DNO licence-specific modelling is available. A subset of the national model has been created to demonstrate the way in which a DNO could populate its own model. This provides a sense check of the level of investment required in one (synthesised) licence area. This synthetic data can be to be replaced by each DNO for its individual licence area(s). Once this process has been completed for the fourteen licences across GB and the DNOs have tuned the modelling assumptions (such as reinforcement trigger points) to reflect their individual design policies and make-up of the network, it is unlikely that the sum of these fourteen models will correspond exactly to the overall GB network model. This would be expected of a disaggregation process and the report makes some observations about modelling quality control and consistency management.

A new tool is now available for evaluating network innovation. The early use of the model has shown a good degree of consistency and flexibility for examining a range of scenarios and different investment strategies. The parameterisation options not only enable licence-specific modelling but also flexibility for sensitivity analysis; this is critical to gaining confidence in the modelling and for understanding the drivers for future investment.

Contents

1 Introduction

This section outlines the background of the project, the scope and objective of the work undertaken, and provides an overview of the structure of the report.

Energy Networks Association appointed EA Technology, in conjunction with Element Energy, GL Noble Denton, Chiltern Power and Frontier Economics, to provide an assessment of required network developments in the low carbon economy, including detailed network modelling of smart grid options. The output is a modelling framework that not only assists in quantifying the Work Stream 3 (WS3) Phase 1 report on a national (Great Britain) basis, but can also be used at a Distribution Network Operator's (DNO) licence level to assess the network-related investment requirements associated with supporting the transition to 'low carbon'.

1.1 Context of the project

This work has been commissioned to feed into the work programme of the Smart Grids Forum (SGF)[5]. 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 Great Britain (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 network challenges, and to provide drive and direction for the development of smart grids.

As of May 2012, there are five work streams within the Smart Grids Forum, with further work streams to be added in the 2012/2013 financial year. The existing work streams cover:

- **WS1:** The development of scenarios for future demands on networks. This work was led by DECC, and established the assumptions and scenarios necessary for the network companies to produce business plans consistent with DECC's transition to a low carbon economy
- **WS2:** The development of a publicly available techno-economic model for assessing smart grid investments. Ofgem has led this work to develop an evaluation framework that can assess, at high level, alternative network development options. The Framework will help inform policy decisions related to smart grids
- **WS3:** Developing networks for low carbon. DNO-led work to assess the network impacts of the assumptions and scenarios from WS1
- **WS4:** Closing doors. Mitigation of the risk that short term smart meter and smart grid decisions may close off options; bringing stakeholders together to identify credible risks to the development of smart grids as a consequence of forthcoming policy decisions which might fail to take full account of the necessary enablers for smart grid development
- **WS5:** Development of future ways of working for the SGF. This looks at how the Forum can best pursue its objectives and communicate effectively with stakeholders

The SGF has chosen to include the provision of an evaluation framework for smart grid investment as part of its work; this forms the core of Work Stream 2. This reflects the current lack of

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

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.

This body of work under Work Stream 3 is a second phase to provide an assessment of required network developments in the low carbon economy, including further quantification and expansion of smart grid options developed in the Phase 1 report[6].

1.2 Objectives of this project

The objective of the project was to develop and populate a model that assesses the value of a smart grid response in distribution networks to a range of low carbon technologies.

This has been achieved by the production of datasets that:

- Are able to characterise the national targets / national levels of uptake of low carbon technologies (LCTs), distributed generation (DG) etc. on a regional or sub regional basis
- Describe a range of typical distribution network types, loading configurations and residential building and commercial property demands (now and forecast) that can provide a modelling framework for the majority of GB network topologies
- Quantify, in terms of costs and headroom released, the range of 'smart grid' mitigating solutions identified in the WS3 Phase 1 report – including the identification of relevant LCN Fund projects and their anticipated delivery timescales
- Combine these measures together in a manner that is consistent with the framework developed for Ofgem under WS2

1.3 Definition of a smart grid

There is no single internationally agreed definition of a smart grid. This report uses the Smart Grid Roadmaps[7] developed by the Electricity Networks Strategy Group (ENSG) as a 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 upon this definition, DECC identified that a smart grid is likely to have the following characteristics[8]:

- **Observable:** the ability to view a wide range of operational indicators in real-time, including where losses are occurring[9], 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. Including adjusting some electricity demand according to the supply available, as well as enabling the controlled use of large scale intermittent renewable generation

[6] The WS3 Phase 1 report is available here: http://www.ofgem.gov.uk/Networks/SGF/Publications/Documents1/Smart%20Grid%20Forum%20Workstream%203%20Report%20071011%20MASTER.pdf
[7] ENSG (2010) A Smart Grid Routemap.
[8] DECC (2009) Smarter Grids: the opportunity.
[9] We note that the prominence given to loss management in this definition has been questioned.

- **Automated:** the ability of the network to make certain demand response decisions. It will also respond to the consequences of power fluctuations or outages, 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

The decision to use this definition gives cognizance to the responses under Ofgem's consultation for WS2, as well as ensuring consistency between WS2 and WS3.

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. DNOs, both in Great Britain 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 focused 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, the mix of technologies that would be capable of providing this functionality had to be identified. Section 5 provides a detailed overview of the 'smart solutions' included in the model that will perform this task. While the list is extensive and is based on the best available information at time of writing, the model can be populated with additional smart solutions as and when better information becomes available.

1.3.1 Differentiation between 'smart grid' and 'smart meter'

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 is currently.

For the purpose of the WS2 model, it was assumed that smart meters are capable of facilitating dynamic[10] DSR from a certain date[11], without the need for any additional investment in smart grid technologies. Consistent with the default assumptions on smart meter functionality in the WS2 report, it is assumed in this report that smart meters can deliver static DSR signals to reduce system-wide costs until the mid-2020s, and dynamic DSR signals to reduce system-wide costs thereafter. Some specific aspects of the detailed functionality of smart meter communications capabilities had not yet been decided. 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. However, it is assumed that specific smart grid investments are required to deliver dynamic DSR signals to reduce local network costs; this presents an

[10] **"Dynamic" DSR**: time-of-use tariffs or other forms of DSR which can be used to shape demand within the day on a real-time or near real-time basis (for example in order to move demand in line with wind generation). By contrast, the term "static" DSR refers to patterns of DSR which are set in advance (such as Economy 7 tariffs) and cannot respond to changes in conditions in real time.

[11] 2023 was assumed as a default in the WS2 model, but this assumption can be changed by model users. A sensitivity where dynamic DSR was only facilitated by smart meters from 2028 was published in the WS2 report.

opportunity for the DNOs to work with the smart grid interface. As in WS2, this report therefore assumes that 'smart grid' and 'smart metering' are not synonymous with each other; but that smart metering is an enabling technology of the smart grid.

1.4 Extrapolation of the SGF-WS2 framework

The WS3 model builds on the framework developed under WS2, but adds significantly greater detail in terms of the number of networks and solutions to be considered within the network element of the model. The CBA wrapper element, which deals with the benefits accrued to the wider electricity sector and which looks at generation, transmission and nationally-driven DSR amongst other things, remains constant in its structure from WS2.

The key differences between the WS2 framework and the WS3 model are summarised in Tables 1.1 and 1.2 below.

Table 1.1 Comparison of 'CBA wrapper' in WS2 and WS3 models

CBA Wrapper	WS2	WS3
Processed scenarios	3 (Low, Medium 1, Medium 2)	4* (Low, Medium 1, Medium 2, High)
Investment strategies	3 (Incremental, Top-down, Counterfactual)	3 (Incremental, Top-down, Counterfactual)
Real options-based analysis[12]	Yes	No**

*The WS3 model calculates one scenario and three investment strategies at a time, to minimise computation time
**This functionality was removed from the WS3 model to increase the speed of computation

Table 1.2 Comparison of 'network element' of models in WS2 and WS3

Network Element	WS2	WS3
Network Topologies	3 (1x EHV, 1x HV, 3x LV)	100 most likely combinations
Clustering Groups	5	10
Daily load profiles	3 (summer mean, winter mean, winter peak)	3 (as per WS2 model)
Headroom spread	1 (average only)	3 (symmetrical*** : low/average/high)
Profiles associated with low carbon technology types and loads amenable to DSR	17	17
No. of solutions and variants	~20	~120

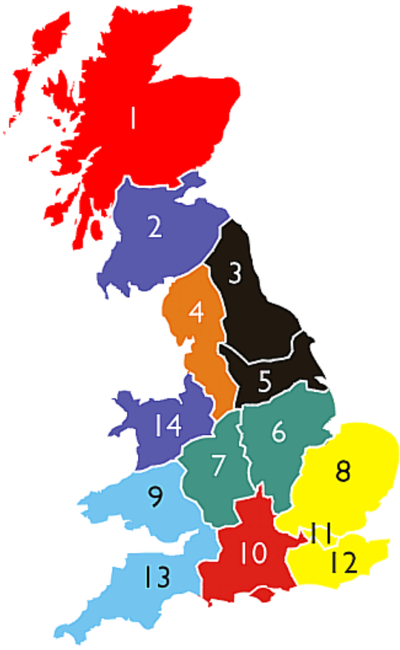
***A single static headroom has been applied for the GB results in this report

[12] The real options-based analysis presented in WS2 considered that the smart strategy undertaken in 2012 (top-down smart, incremental smart or conventional) could be adjusted in the mid-2020s, in response to updated information about the prevailing scenario. This analysis found that there was little option value associated with undertaking smart investments in the first period on average across GB. The use of the real options-based model alongside the more complex network modelling used in WS3 would lead to unacceptable model run times. Given this, and the fact that option values were not found to be important in the WS2 model, it was decided to omit the real options analysis from the WS3 work.

1.5 Production of two models

In order to translate the GB picture to a DNO licence area, two models have been produced; a national (GB) model, and a licence specific model. Functions of the two models are tabled below:

1. GB model – a single model to represent the GB case (including total number of feeders, and typical make-up)



2.Licence model – a second single model, that can be tailored to look like any of the 14 GB DNO licence areas

Figure 1.1 GB and DNO licence model comparison

Table 1.3 National and DNO Licence specific model functions

National model	Licence specific model*
Can provide an estimate of GB-wide generation costs	Does not provide an estimate of generation costs
Will model nationally-driven DSR, and the potential change seen to domestic demand profiles	Model unable to account for nationally-led DSR[13] and any automatic change to demand profiles
Generic load profiles	Customisable load profiles
No region specific results	Region specific results
Both a cross value-chain social and a networks only CBA	Networks only CBA
National 'tipping points' will be identified	Regional / licence specific tipping points only

*For the licence specific results in this report, a fabricated synthetic dataset has been developed to show how the model can operate. Any resemblance to a real GB DNO licence is purely coincidental.

[13] However, load profiles after the application of nationally-led DSR can be copied from the national model into the licence specific model.

1.6 Structure of this report

The report is structured as follows:

- **Section 2 Overview of methodology**
  This section presents the methodology that underpins the report, considers the need for flexibility in approach, and details the overall scope of the analysis, together with the key complexities encountered in the work.
- **Section 3 Characterisation of low carbon technologies uptake levels**
  This section assesses uncertainty through the scenarios, defines 'low carbon technologies' (LCTs), and gives an overview of the scenarios for each technology uptake. It also provides clustered forecast for LCTs.
- **Section 4 Development of updated network models**
  An overview of network models, feeder loads and profiles, and a matrix of 'typical' network topological types are provided in this section. Assumptions are reviewed, and new network models are considered, together with an economic model for smart grid solutions.
- **Section 5 Characterisation of conventional and smart interventions**
  This section gives an overview of representative solutions, variants and enablers; it describes how solution parameters have been captured, and converts the WS3 phase 1 report to a smart solution set, considers conventional solutions for WS3, whilst also considering other interactions.
- **Section 6 Modelling the wider electricity sector**
  In this section, we look at the way in which the model deals with the wider electricity sector. This incorporates the cost of generation across GB and how nationally-led DSR may be utilised to reduce this cost. The interface between this DSR and the interventions that may subsequently be applied by network operators at a local level is also discussed. We also describe the discount rate applied by default in the GB-wide model for NPV calculation of investment.
- **Section 7 A systems approach to innovation deployment on networks**
  Step changes as a result of innovation are addressed in this section; tipping points are explained and identified.
- **Section 8 Model results**
  This section presents the results for each scenario, and of some of the key outputs of the model, including a commentary on differences between the results of WS2 and this WS3 model.
- **Section 9 Report Conclusions and Recommendations**
  The conclusions of this study, implications for RIIO-ED1 and suggestions for further development and analysis are drawn out in this section.

Further detail on the model, analyses, scenarios and solutions, can be found in the appendices.

2 Overview of methodology

In this section, we provide an overview of our proposed framework for the assessment of required network developments in the low carbon economy. We discuss the need for flexibility in this work, the scope of the analysis, and then provide an overview of the main challenges, or complexities, faced in developing the framework and corresponding datasets, and how our analysis addresses these challenges.

2.1 Background

An electricity network has, conceptually, a simple role, which is to provide a route to transmit electrical energy from generator (the source) to where the power is consumed (the sink). Since the 1930s the electricity flow in GB has followed a simple, one-way process from large generation plant, to transmission networks, then distributed to customers via largely passive networks. The performance and investment needs of the distribution network under this regime are relatively predictable.

However, as GB moves to decarbonise, new generation sources (such as solar photovoltaics, onshore wind and biomass plants), and new demands (such as heat pumps and electric vehicles) will appear in new places on the network, changing the, once static and predicable, power flows. The speed, location and extent, to which this occurs, will significantly influence the shape and operation of the power system, with a consequential uncertainty around the scale of investment.

In such multi-dimensional problems, scenarios are helpful in identifying plausible combinations of generation sources and load demands. For this assessment, we use two sources of scenario:

- Distributed Generation (onshore wind, biomass, etc): National Grid
- PV, Heat Pumps, Electric Vehicles: DECC, via SGF-WS1

Different mixes of large-scale generation will place different challenges on the conventional network design and operation

There is a natural interplay between generation connected to the transmission network and that connected at distribution voltages. As more generation connects to the distribution network, a reduction in demand will be seen at transmission levels as local generation nets off local load. Conversely, the integration of significant amounts of inflexible and intermittent generation (such as nuclear or wind) on the transmission network may be facilitated by DSR, which itself affects loads on the distribution networks. It is important to consider the effects of generation at all network voltages, as this impacts both on the demand profiles and electrical performance of the network.

National Grid's 'Gone Green' scenario work maps out medium and low decarbonisation scenarios for installed capacity up to 2050. It may be seen from Figures 2.1 and 2.2 that the shape of the mix can look very different out to 2050, depending on outturn policy and market drivers.

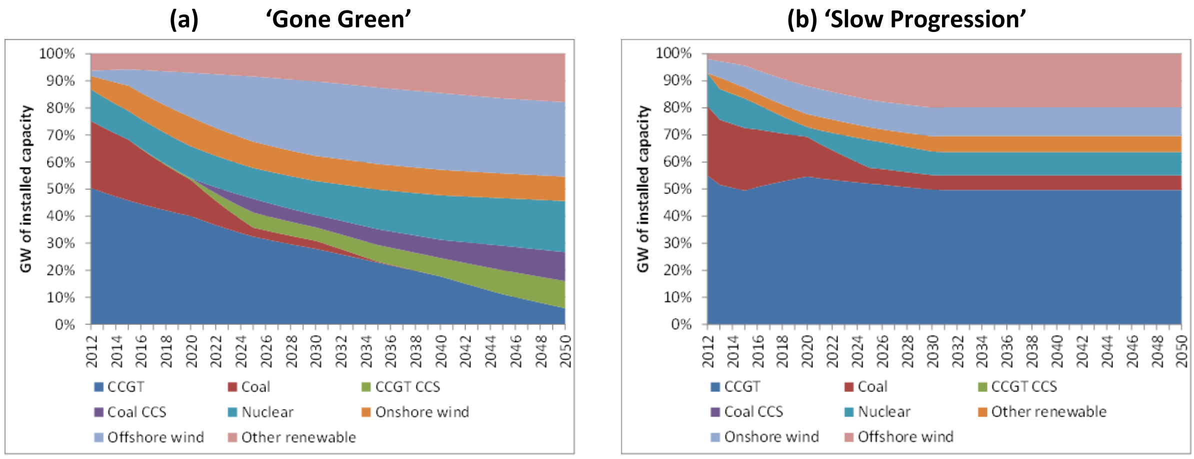


Figure 2.1 Redpoint analysis for the ENA, using two of National Grid's scenarios

The increase in intermittent generation may also lead to an increase in value from signalling to consumers the cost differences associated with the time that they use electricity. This is something that smart grid networks and technologies may facilitate.

The roll-out of LCTs is expected to be market-led in its response to policy drivers. This means that take-up is likely to be irregular with each LCT presenting a different challenge.

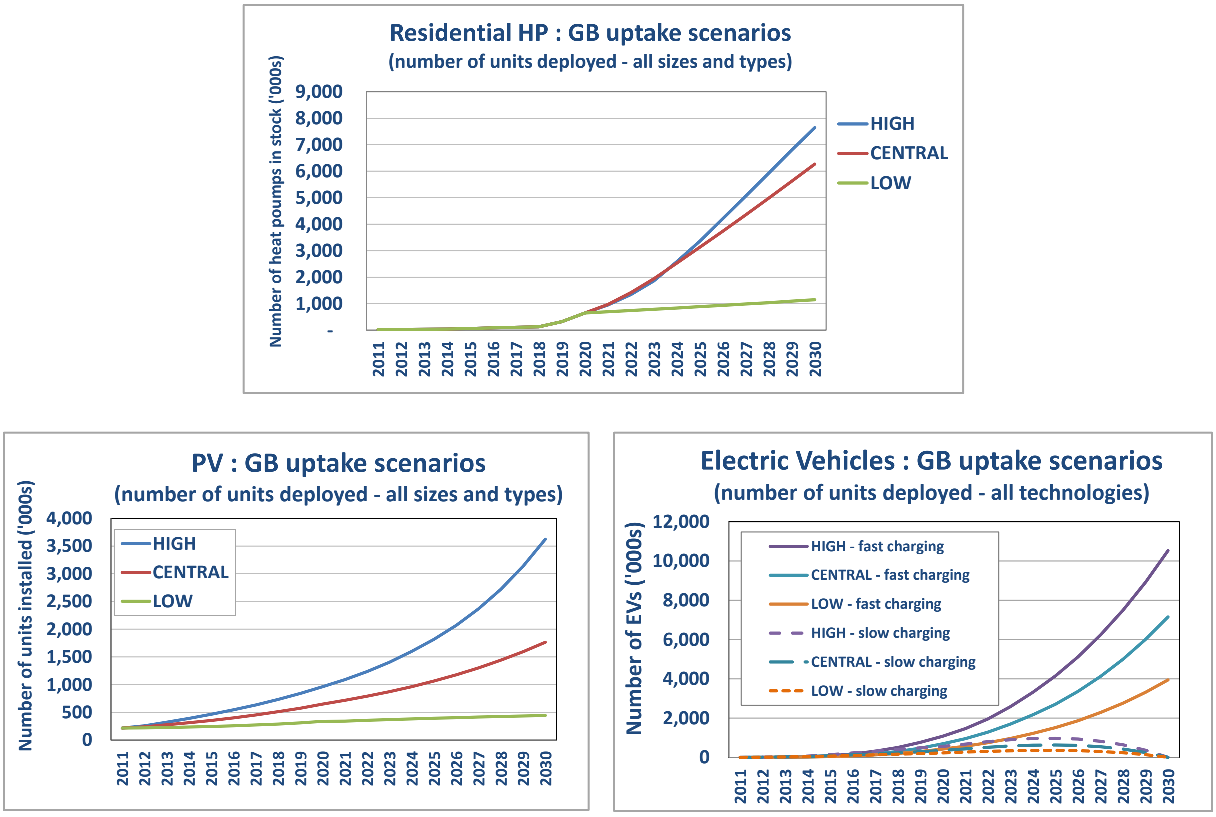


Figure 2.2 GB uptake scenarios for different forms of low carbon technology (Source: DECC, WS1)

Similarly, networks are not uniform; variances may be seen in city centre networks as opposed to a market town or rural network. This piece of work examines what the networks of the future will have to look like to accommodate this projected growth in LCTs in order to facilitate a move towards a low carbon economy for Great Britain. In an uncertain world, different mixes of embedded generation and LCT penetration will place different challenges on a network's conventional design and operation.

Local impact on LV networks is already being seen as a result of policy drivers; for example under the Government's Feed-in Tariff incentive for photovoltaics (PV). In response to Government and policy signals, carbon targets are being set, meaning that the role of heat pumps, PV and electric vehicles (EVs) are becoming increasingly important.

2.2 The need for flexibility

A considerable amount of uncertainty still exists regarding the demands that will be placed on the distribution network by various low carbon technologies (LCTs) in terms of the profiles associated with these LCTs, and the levels of penetration seen in different areas of the country. Furthermore, the various smart solutions that can be deployed on a network are, in many cases, not yet in wide scale use; hence the costs attributed to them are best estimates at this stage.

There is currently a large programme of trials on smart grid interventions being undertaken through the Low Carbon Networks (LCN) Fund. 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 associated with the cost of a solution, or level of benefits it releases, becomes available. Likewise, as more robust data is available on the subject of, for example, domestic charging patterns of electric vehicles, it is important that these profiles can be modified within the model to reflect this observed behaviour.

2.3 Overall scope of the analysis

Figure 2.3 indicates schematically the scope of the activity within this project and the structure of the inputs to and outputs from the created model.

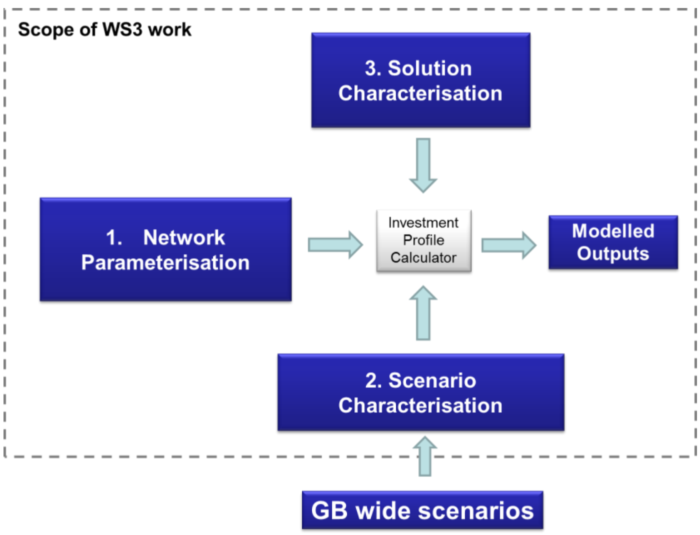


Figure 2.3 Scope of WS3 work

Block 1 represents the network parameterisation. This is necessary as the model must consider the entire GB distribution network at 33kV and below. Clearly to attempt to model such an extensive network on a circuit-by-circuit basis would be incredibly time consuming and such a 'nodal model' would not be able to be executed in a reasonable time. Instead, the approach taken consists of devising a number of 'representative' network elements that can then be replicated in the appropriate proportions to give an overall network that is a reasonable approximation to the GB distribution network.

In order to develop this parameter-based (or 'parametric') model, a number of standard 'feeders' have been defined. These feeders are then given parameters such that when summated, the overall GB-wide picture (or the situation for a specific licence area) demonstrates an appropriate number of feeders, with recognisable parameters in terms of their length, rating etc. A commentary on how such a parameterised network was devised is provided in Section 4.

In order to determine the levels of additional strain that will be placed on distribution networks through uptake of various LCTs, a set of scenarios must be defined, to clearly identify the projected increases in the various technologies (Block 2 in Figure 2.4). These scenarios are based on figures provided as outputs from WS1 (which is led by DECC). The figures are also consistent with those applied to the Evaluation Framework created in WS2 insofar as this was practical. Section 3 describes these uptake levels and scenarios and discusses how they are applied to the model in more detail.

The impact of the LCTs on networks must be quantified to allow the model to determine the level of investment required on the network. To ensure that this impact was captured in a consistent manner, the concept of 'headroom' is used. Headroom refers to the difference between the load experienced on a network or asset, and the rating of that network or asset. If the rating exceeds the load, then there is a positive amount of headroom and investment is not required. However, once load exceeds rating then the headroom figure is negative and investment to release additional headroom must be undertaken. Figure 2.4 demonstrates this.

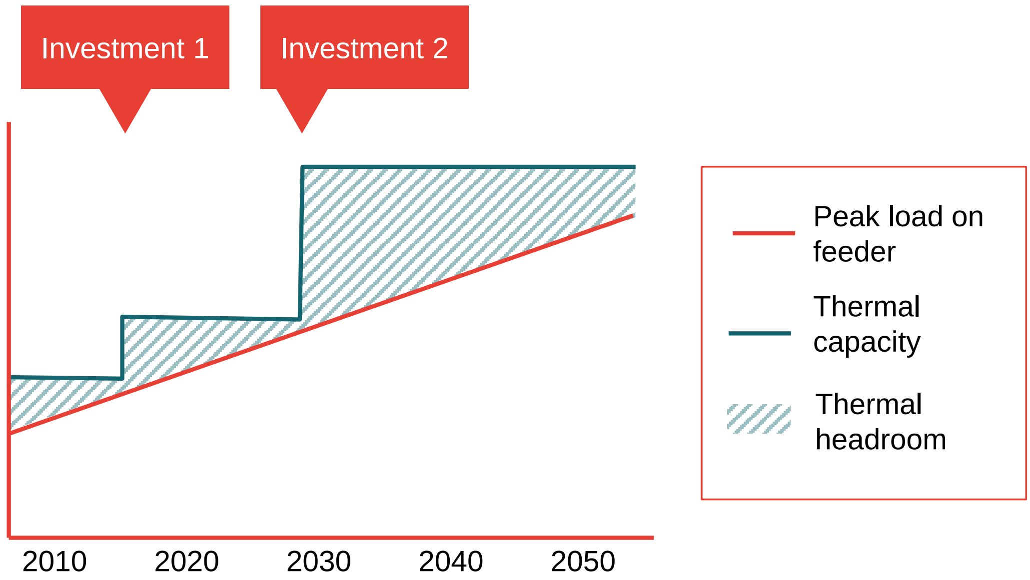


Figure 2.4 Illustration of network investments (Source: Frontier Economics)

The advantage to using headroom in this way is that it allows numerous parameters to be discussed on a common base. The example above was focusing on the load on the network (the thermal headroom), but it is equally applicable to look at the system voltage and fault level on a headroom basis. This allows the effect of technologies on several of these parameters to be captured simultaneously; i.e. if a particular LCT contributes to a reduction in both thermal and voltage headroom, this can be easily identified.

The next block (Block 3 in Figure 2.4) accounts for the necessary investment on the network. In the event of a breach of any type of headroom, a solution must be deployed to release additional headroom on that portion of the network. The most appropriate solution (be that a ‘smart’ intervention, or a ‘conventional’ solution; i.e. one readily available and widely used today) is selected and applied to the network, while the various headroom measures are recalculated. Section 5 describes the way in which these solutions are categorised and selected as appropriate.

Once the scenarios in terms of uptake levels have been applied to the parameterised network, and the most appropriate solutions have been applied, the model produces a number of outputs. These include the total expenditure over the period, the most common solutions applied, and the type of network requiring the most significant investment.

2.4 Key complexities

Developing the assessment framework under WS3 has involved a number of key challenges and complexities. Under the philosophy of flexibility in approach in this work stream, such issues have been captured in a series of discussion papers. Each discussion paper has been presented to the Steering Group of Network Operators, and the outcomes documented in a decision paper, subject to amendments, and agreed by all parties. The key complexities under this Framework’s development have included:

- Scenarios summary
- Feeder parameterisation and composition
- Building types
- Building and appliance efficiency
- Smart solutions
- Conventional network solutions
- Merit Order Stack

2.4.1 Scenarios summary

The technology uptake forecasts incorporated into the Work Stream 3 model have been modelled; the scenarios are consistent with those developed in the Work Stream 1 activity (unless otherwise stated) and have been cross-checked with DECC for consistency with the scenarios under-pinning policy development.

Technologies considered under the scenarios are:

- Heat pumps (residential, business and public)
- Electric vehicles

- Photovoltaics
- Distributed generation (taken from National Grid scenarios)

This is discussed further in Section 3.

2.4.2 Feeder parameterisation and composition

In order to represent the entire GB distribution system without employing a fully nodal model that would be unmanageably large, a series of standard networks needed to be defined. However, having defined these networks, it was also necessary to calculate the level of load currently experienced on these networks, so as to give a starting headroom position and hence accurately identify the point at which investment is required. This necessitated a detailed analysis of feeder composition; such that the loads associated with the representative building types could be summated to give a true representation of network loads.

This is discussed further in Section 4.

2.4.3 Building types

To enable representative LV feeder loads to be generated, it was necessary to model the point loads on the feeder in more detail. This involved considering a range of different building types in order to represent their different demand levels and patterns. The building types were chosen to provide sufficient variation to represent the loads on the generic feeder types whilst keeping the number of types small enough to be manageable. In order to assess the solution sets for the future scenarios defined in Phase 1, the model needed to be able to estimate LV feeder demand profiles at each year of the scenario. A sample of building types was included in the model.

This is discussed further in Appendix C: Customer Load Analysis.

2.4.4 Building and appliance efficiency

Given that the starting load position has been calculated via detailed analysis of feeder composition, based on building loads, some thought had to be given to how these building loads would vary in the future. To facilitate this, the loads are disaggregated by type within a building (heating, lighting, consumer electronics etc.) and the change in efficiency over time of these various loads is also modelled; representing the move to energy efficient lighting and the improvement in efficiency of white goods etc. By combining this with changes to insulation levels of buildings, a detailed picture can be built up showing how loads are likely to change (before the addition of LCTs) between 2012 and 2050.

Further detail on this can be found in Section 4 and Appendix C.

2.4.5 Smart solutions

EA Technology identified the core set of technologies to be modelled in WS3 using the solution sets from the Phase 1 report as a guide. The final smart solutions set can be seen in Appendix D, (Table 13.3). The technologies have been categorised into a core set of 20 representative solutions each with a number of associated variants.

A framework for capturing solutions has been developed as part of this analysis, it is envisaged that this will continue to evolve and develop as learning is generated from smartgrid projects both in GB and internationally.

2.4.6 Conventional network solutions

The smart grid will be built upon a blend of both ‘conventional’ and ‘smart’ solutions. Therefore, in parallel with the Task 3 exercise to quantify the solutions that underpin the solution sets of the WS3 Phase 1 report, it was necessary to ensure that the conventional solutions had been adequately captured.

Using the WS2 solutions as a starting point, the Network Operators funding WS3 were asked to review both the solutions and their deployment costs to ensure alignment with current custom and practice. The model under consideration included a range of conventional reinforcement options. Under business as usual 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 modelled solutions are described in more detail in Section 5.

2.4.7 Merit order stack

When considering the myriad solutions (both conventional and smart) that could be applied to a network, there needs to be a robust way to determine which solution is the most applicable to a given network in a given situation. To perform this complex task, a ‘cost function’ was defined that allows the relative merits of each solution in terms of its cost, the headroom it releases and any other second order benefits or costs associated with it, to be evaluated. All solutions can then be dynamically ranked for all network types over all years.

Full details on how this is incorporated, including the cost function, can be found in Section 5 and Appendix D.

3 Characterisation of low carbon technologies uptake levels

This section assesses uncertainty through the scenarios, defines 'low carbon technologies' (LCTs), and gives an overview of the scenarios for each technology uptake. It also provides clustered forecast for LCTs.

3.1 Definition of low carbon technologies

The definition of the low carbon technologies sector stems from the development of the environmental goods and services sector, covering technologies to provide solutions to problems in the air, noise, marine pollution, land and water contamination areas, as well as activities around environmental analysis and consultancy, waste management and recycling. With the recognition of the sector being a stimulus not only in terms of innovation, but as a result of UK and European policy drivers and as an economic stimulus for 'green' jobs, the 'low carbon technology' sector has expanded to cover hydro, wave and tidal power, geothermal, nuclear energy, carbon capture and storage[14]; this report focuses on the low carbon technologies of heat pumps (HP), photovoltaics (PV), electric vehicles (EV) and Distributed Generation (DG) in the form of onshore wind and biomass.

3.2 Overview of scenarios for technology uptake

Historically the rate of load growth on the distribution networks has been closely correlated to the rate of housing growth and economic activity. In the coming decades, the rate of load growth is expected to diverge significantly from these established trends due to both energy efficiency measures on demand and the anticipated uptake of low carbon technologies (LCTs). Of particular concern to distribution network operators is the expected electrification of heating and transport technologies; sectors of energy use that are currently dominated by other fuels. The increasing proliferation of distributed generation technologies, encouraged by financial incentives and increasingly stringent regulations on the energy performance of buildings, will also impose significant new stresses on the electricity distribution networks.

A key objective of the modelling is to provide an understanding of the range of potential impacts of the uptake of LCTs on distribution networks. This requires forecasts of the rate and extent to which these technologies will be taken up, how they will be used and where on the network they are likely to be connected. In the following we describe the forecasts for increasing connection of LCTs that have been used as inputs to the model and the analysis that has been performed to translate technology uptake to a model of load growth at a national and localised level.

3.2.1 DECC scenarios for technology uptake

The following low carbon technologies have been identified as those expected to have greatest impact on the low voltage networks:

- Photovoltaics (PV)
- Heat pumps

[14] BERR, Low Carbon and Environmental Goods and Services; an industry analysis, 2009.

- Electric vehicles (EVs)

Developing scenarios for the level of future uptake of technologies that are new or currently have relatively limited markets in the UK is challenging. A large amount of work has been done to develop such scenarios to inform the development of government policies aimed at supporting investment in LCTs and to help the government understand the contribution that these technologies can make toward meeting carbon reduction and renewable energy generation obligations.

As part of this work we have not attempted to develop new scenarios for the rate of uptake of LCTs. Instead, we have adopted a range of scenarios for the growth of the markets for each of these technologies that have been developed by government on the basis of the large amount of analytical work that has been done to-date. In particular the scenarios are consistent with scenarios described in DECC's Fourth Carbon Budget (CB4), also referred to as the Carbon Plan[15], which sets out a range of possible pathways toward meeting the UK's first four carbon budgets (up to 2027) and beyond, toward the 2050 objective of an 80% reduction of carbon emissions from 1990 levels.

In the case of each technology, DECC has provided three scenarios for the rate of uptake – low, mid and high. These scenarios reflect varying assumptions for the on-going levels of policy support, barriers to consumer uptake and assumptions regarding the rate of technology improvement and commercialisation.

These scenarios are described below.

3.2.2 Heat pumps

The heat pump uptake scenarios provide a split between the residential, business and public sectors, although in all scenarios it is uptake in the residential sector that is expected to dominate. Uptake follows the same trajectory in each of the three scenarios over the period to 2020, with relatively limited uptake forecast until the latter part of this decade, before the scenarios diverge post-2020.

The DECC low carbon technology scenarios forecast the uptake of heat pumps to 2030, but further assumptions were required to forecast uptake from 2030 to 2050. To extend the uptake forecasts to 2050, a constant percentage increase in the heat pump stock has been assumed in each scenario. In the case of the High and Mid uptake scenarios, it was not considered reasonable to assume a continuation of the pre-2030 growth rate as this would have led to extremely high levels of heat pump penetration in the housing stock. In the case of the High and Mid scenarios, an annual growth rate of 4% has been assumed. In the case of the low scenario a growth rate of 7% is assumed, which is consistent with the pre-2030 growth rate. A higher percentage growth rate in the low scenario is reasonable given the far less mature stage of the market.

The scenarios for heat pump uptake in the residential and non-domestic sectors are shown in the plots below. In each case, the total number of heat pumps in operation in the building stock is plotted.

[15] http://www.decc.gov.uk/en/content/cms/emissions/carbon_budgets/carbon_budgets.aspx#

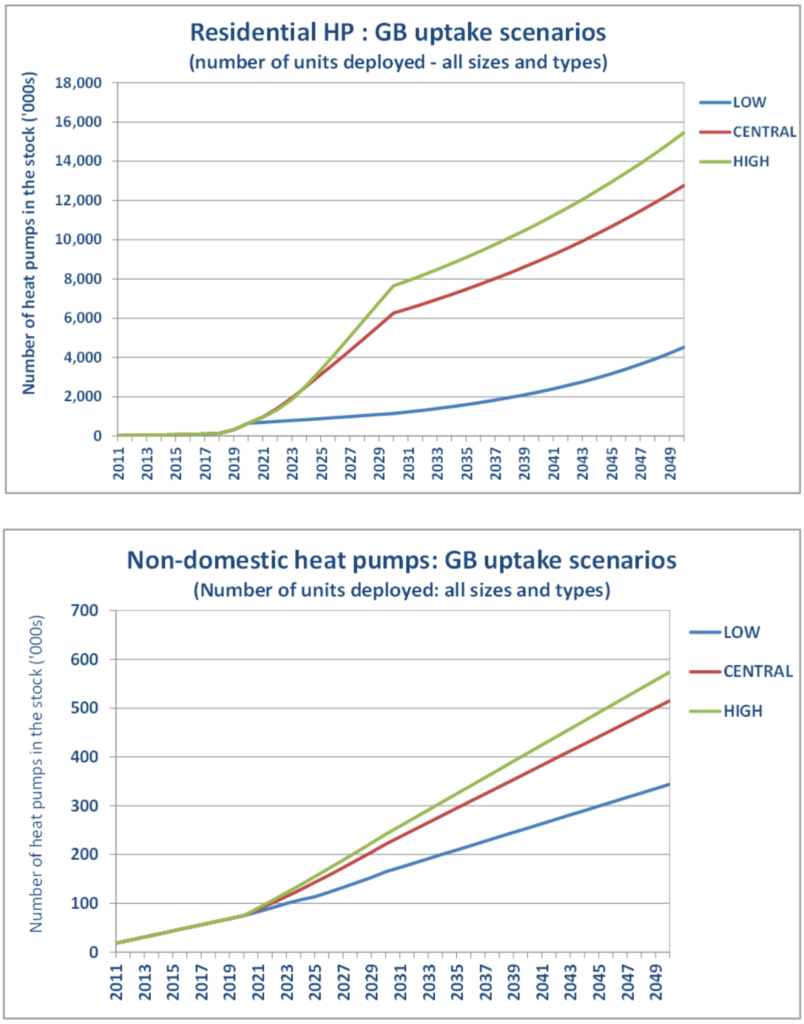


Figure 3.1 **GB scenarios for the uptake of heat pumps in both residential and non-domestic sectors (Source: DECC and Element Energy)**

Figures 3.2 and 3.3 show winter average heat pump demand profiles; the domestic profile is based on trial data, the commercial profile is from synthesised data.

(a) Domestic **(b) Commercial**

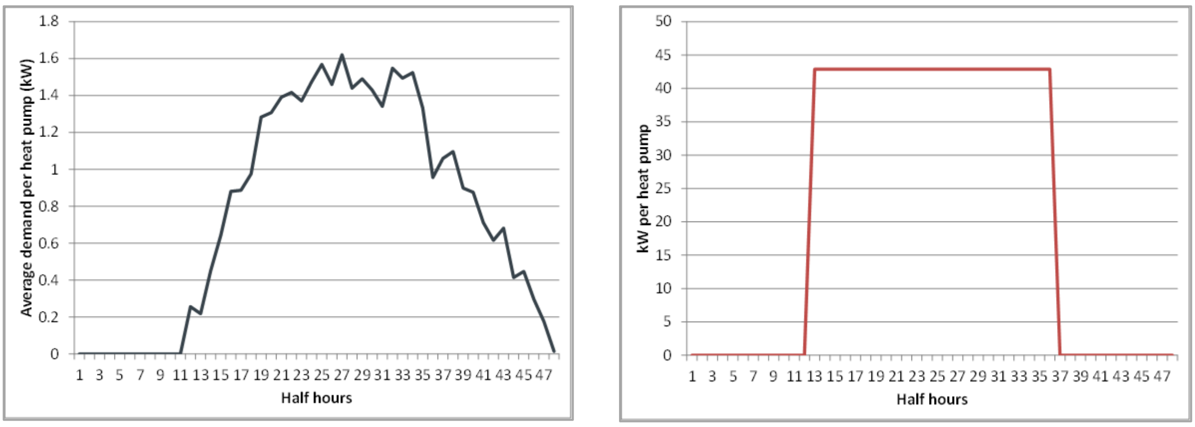


Figure 3.2 **Winter average heat pump demand**

3.2.3 Electric vehicles

The scenarios for the increasing penetration of electric vehicles have been developed by the Department for Transport (DfT) as part of its autumn 2011 strategy for delivery of the fourth Carbon Budget[16]. The scenarios are driven by targets for the average emissions of new cars and vans in 2030, which are set-out in various Fourth Carbon Budget scenarios, as shown below in Table 3.1.

Table 3.1 Average emissions targets for new cars and vans as set-out in various scenarios contained within the Fourth Carbon Budget

Carbon Budget Scenario	Scenario	Average new car emissions	Average new van emissions
CB4: Sc. 4	Low	70gCO_2/km	105gCO_2/km
CB4: Sc. 1	Medium	60gCO_2/km	90gCO_2/km
CB4: Sc. 2 & 3	High	50gCO_2/km	75gCO_2/km

Electric vehicle uptake scenarios have been developed for the period to 2030 with the aim of meeting these emissions targets for the average new vehicle emissions in 2030. These scenarios are shown in the plot below, as cumulative numbers of electric vehicles in service in each year.

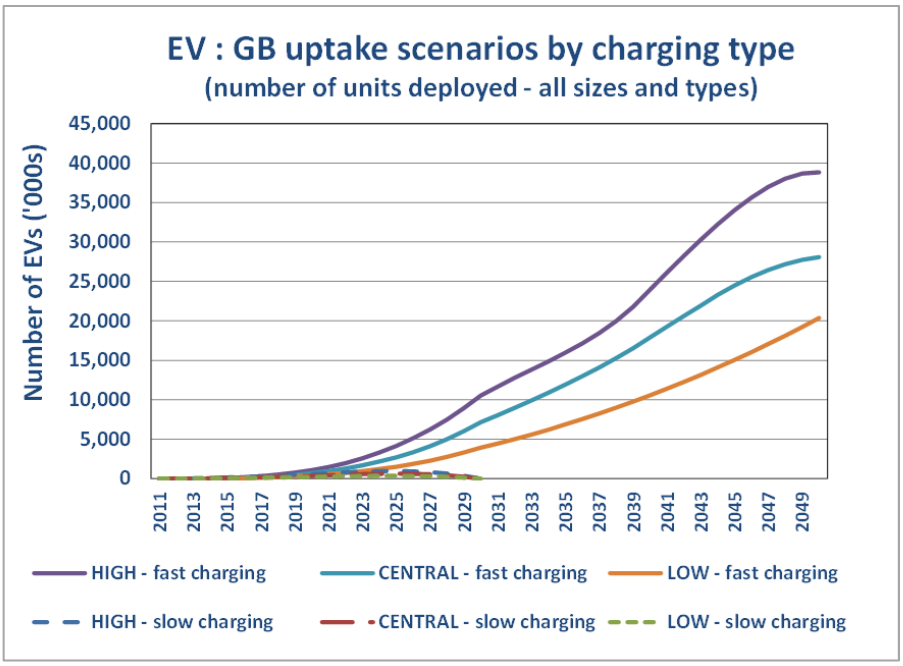


Figure 3.3 Scenarios for the cumulative uptake of electric vehicles (Source: DECC and Element Energy)

The number of EVs includes all vehicle technologies, different forms of ownership (e.g. fleet, company and private) and both cars and vans. A split between fast and slow charging is shown.

Based on trial data, taken from the TSB Ultra Low Carbon Vehicles Demonstrator Programme, Figure 3.4 shows the demand profile for EVs over the course of a day (from midnight to midnight). It is noted that at this time, the TSB study, whilst not fully published, provides the largest body of evidence of EV use in Great Britain. The trial incorporates:

- 8 consortia running projects

[16] http://www.theccc.org.uk/reports/fourth-carbon-budget

- Including 19 vehicle manufacturers
- 340 vehicles (electric, pure hybrid and fuel cell vehicles).
- 110,389 individual journeys (from December 2009 to June 2011)
- 677,209 miles travelled (1,089,862 km)
- 19,782 charging events
- 143.2 MWh of electricity consumed

The TSB trial results are all based on first generation EVs. It is anticipated that second generation vehicles are likely to contain larger batteries, that will consequently draw more power from the electricity distribution network – a sensitivity of this is presented in the result section.

Details on how Figure 3.4 has been derived are provided in Appendix B.

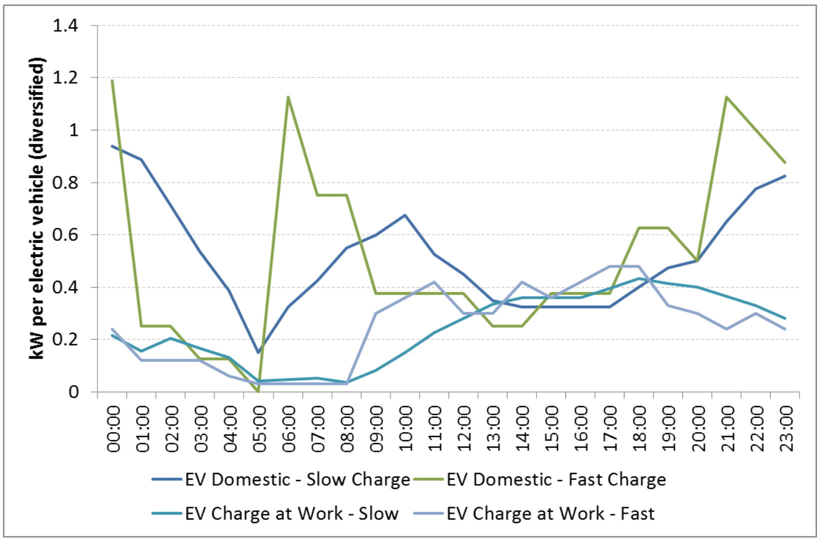


Figure 3.4 Diversified EV charging profiles (Source: EA Technology based on data from the TSB's, Ultra-Low Carbon Vehicles Demonstrator Programme, Initial Findings, 2011[17])

Further, the 'time of day' used for charging apparent from the TSB data does look counterintuitive, i.e. a peak around midnight, rather than early evening (as might be expected). This is clearly an area where improved data would be welcomed, as if there was a tendency towards winter weekday evening charging then the network impact would be significantly greater than modelled.

While DfT's approach is to remain technology neutral, enabling the market to select the most appropriate technologies to achieve CO_2 targets, it has been necessary to make some assumptions regarding the relative merits of different electric vehicle technologies and the importance of particular vehicle attributes, such as cost and range, to different kinds of consumers. These scenarios can therefore be disaggregated further into different vehicle technologies (plug-in hybrid, range extender and battery electric) with associated assumptions regarding usage characteristics (e.g. daily mileage), vehicle efficiency, charging characteristics and the location at which they are likely to be charged (i.e. home, work or at public charging points). All these characteristics are important for determining the size of the demand and charging profile that electric vehicles are likely to impose on distribution networks. Further details on the assumptions behind electric vehicle uptake are given in Appendix B.

[17] TSB, Ultra-Low Carbon Vehicles Demonstrator Programme, Initial Findings, 2011: http://www.innovateuk.org/_assets/pdf/press-releases/ulcv_reportaug11.pdf

3.2.4 Photovoltaics

The capacity of photovoltaics connected in the UK has increased dramatically over the last few years, fuelled by financial incentives (the Clean Energy Cashback scheme or Feed-in Tariff (FiT)) and significant drops in the price of PV modules. A recent revision to the FiT subsidy levels is expected to cool demand to some extent, nonetheless distribution networks are likely to see a large increase in PV connections over the coming decades.

The forecasts for PV uptake used in this work are based on the DECC 2050 scenarios. The High scenario assumes that by 2050 there will 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 (UKERC) in 2007[18], which estimates that the UK could realistically achieve 16 GWp of installed capacity by 2030. An interesting comparison and illustration of the pace of PV uptake may be seen with Germany, which has 20GW of PV installed on an 80GW system. In December 2011 alone, Germany installed 3GW of PV.

The Mid scenario 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. This is over 10 times the current number of installations (based on figures from November 2011).

The Low scenario takes account of the current levels of growth of the PV market, but then projects a low level of future growth. This assumption implies that there remain significant barriers to the installation of PV, largely financial, that are not overcome.

As for heat pumps, the DECC figures only extend to 2030. For the low and mid scenarios, a consistent growth rate was applied post-2030 to that observed in the decade leading up to 2030 (2.5% and 9% per annum respectively). However, for the high scenario, an approach similar to that adopted for heat pumps (annual growth of 6%) was used as a continued extrapolation at the same rate as the growth experienced in the period 2020 – 2030 would result in unfeasible levels of PV connecting.

These three uptake scenarios are shown (including both domestic and non-domestic scale installations) in the figure below in terms of the cumulative capacity connected (MWp).

[18] A road map for photovoltaics research in the UK, Professor David Infield, UKERC, August 2007.

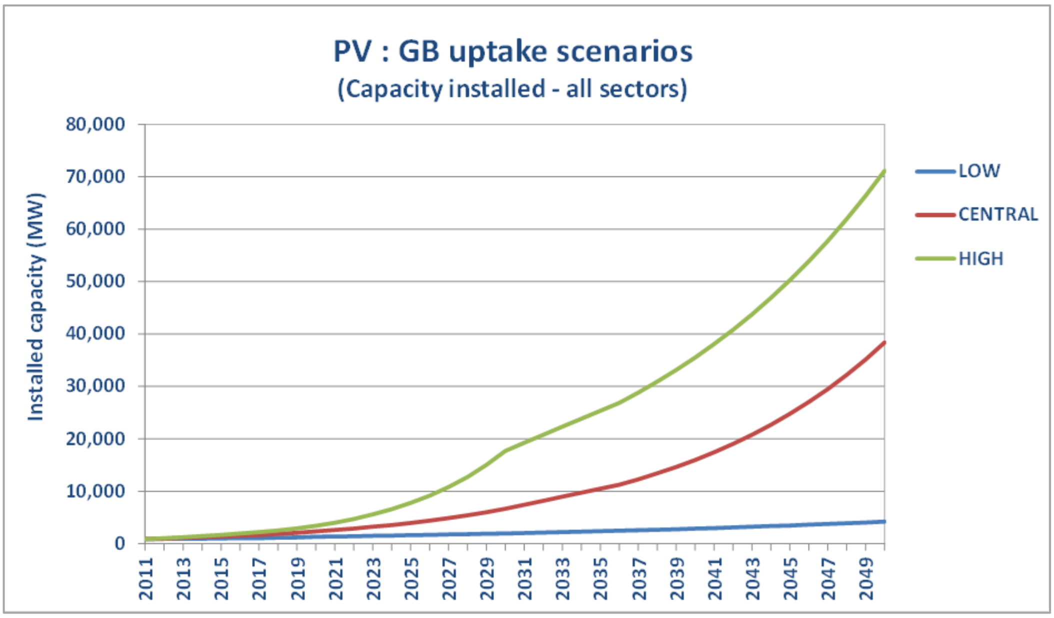


Figure 3.5 **Uptake scenarios for photovoltaics, in terms of cumulative generating capacity installed (Source: DECC and Element Energy)**

3.2.5 Scenario combinations used in the modelling

The WS2 activity considered two different combinations of the individual technology scenarios to develop over-arching technology scenarios as follows:

- ***Scenario 1:*** included 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[19]. (Note that the Work Stream 2 activity also included ***Scenario 2***, based on the same roll out of low carbon technologies as Scenario 1, differing only in the assumption on customer engagement with DSR, which was assumed to be lower for Scenario 2.)
- ***Scenario 3:*** was 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 in Scenarios 1 and 2 (i.e. low technology uptake scenarios), and the generation mix contains less inflexible and intermittent low-carbon plant.

The decision was taken that, for consistency with Work Stream 2, these two over-arching scenarios (together with the variant regarding low DSR availability) should be maintained. The modeling of an additional third scenario was also agreed, in which high technology uptake is assumed across all technologies, thereby providing an upper bound. In order to allow consistency across the scenario range, this scenario is labeled "**Scenario 0**" thus allowing the uptake levels of LCTs to decrease as the Scenario number increases.

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

It should also be noted that, again, consistent with WS2, the National Grid scenarios regarding generation have been applied. Three of our modelled scenarios (Scenarios 0, 1, 2) make use of National Grid's "Gone Green" scenario, with the "Slow Progression" scenario applied to Scenario 3.

The combinations of LCT uptake and generation scenarios in these four over-arching modelled scenarios are summarised in the table below.

Table 3.2 Summary of the LCT uptake and generation scenario combinations underpinning the over-arching future scenarios incorporated into the model

	Heat pumps	Electric Vehicles	Photovoltaics	Generation
Scenario 0	High	High	High	Gone Green
Scenario 1 & 2	High	Mid	Mid	Gone Green
Scenario 3	Low	Low	Low	Slow Progression

The datasets from WS1 (DECC) have been provided for reference in Appendix F.

An overview of the peak electricity demand extrapolated for the modelled period against Scenario 1 is shown below.

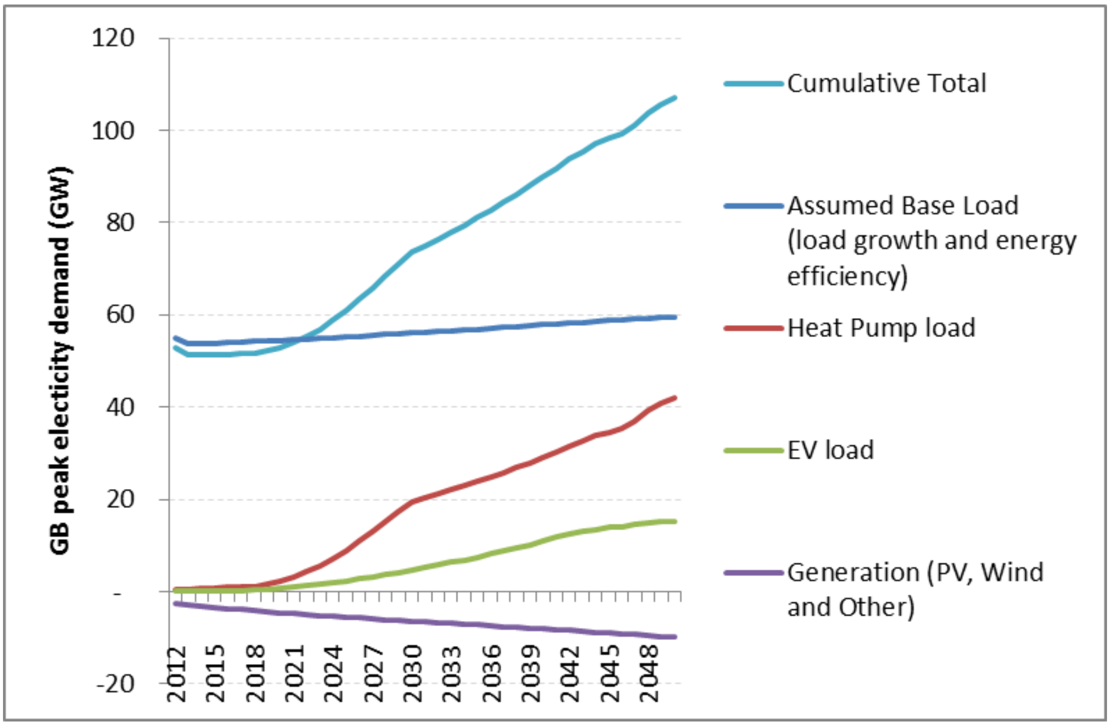


Figure 3.6 Peak electricity demand for Scenario 1 showing the contribution of EV and HP load, together with the demand reduction effects of PV. The base load factors in both load growth and demand reduction

3.2.6 Disaggregation of technology uptake

The LCT uptake scenarios provide ranges for the potential penetration of technologies at a GB-wide level. In order to understand how this will drive load growth and investment in the distribution networks, it is necessary to develop a view of how the technology uptake might be distributed geographically.

A two-stage approach has been taken to develop a geographical disaggregation of the GB-wide uptake scenarios. In the first step the country has been divided into a number of regions, such that any regional differences that might drive differences in the rate of uptake of technologies can be taken into account. The regional variations that can have an influence on propensity to take-up technologies include the composition of the building stock, the extent of urbanisation and the level of solar irradiation, among a range of other factors. Following the disaggregation of uptake to a regional level, a further analysis is undertaken to predict how the new load might be disaggregated across the LV networks within a region, for example to what extent the loads might be expected to occur within suburban residential networks, town centre networks or lower density rural networks. This requires the regional view on the uptake of technologies to be combined with the analysis of typical LV network loads, which is described in Appendix B.

These two-stages of the geographic disaggregation of the LCT uptake are described in more detail in the following.

3.2.7 Regionalisation of the model

The disaggregation of technologies to a regional level is based on sub-division of GB into five regions, as follows:

Region	Description
Region 1	Scotland
Region 2	North West North East Yorkshire and the Humber West Midlands East Midlands
Region 3	Wales[20]
Region 4	South West South East East of England
Region 5	London

Figure 3.7 Sub-division of GB into five regions for technology uptake and load modelling purposes (Source: Element Energy)

This sub-division of the nation, while broad, is of sufficient resolution to capture a number of important variations that can influence technology uptake, such as the differences in average levels of solar irradiation from north to south and the differences in average temperatures. The differences in the building stock between the regions have been analysed on the basis of House

[20] In order for the model to be applicable to DNOs, the boundaries of regions must coincide with the boundaries of DNO licence areas. As a result, the "Wales" region includes the portion of the SP-Manweb licence area within England.

Condition Survey data for England, Scotland and Wales. In the case of the non-domestic building stock, rateable value data (published by the Valuation Office Agency) has been used to derive regional statistics for the composition of the stock, in terms of floor space by premises type. Each region has been further sub-divided into areas that can be classified as Urban, Suburban and Rural. The distribution of the building stock and differing mix of building types between urban, suburban and rural areas is important to understand, as it allows appropriate mapping of load onto LV network types corresponding to areas of different rural / urban character. The designation of LV network types between urban, suburban and rural networks is discussed further in Appendix B.

The disaggregation of LCT uptake scenarios between these five regions has been based on the understanding of regional variations of the building stock and relevant environmental factors, as described above, combined with detailed models of consumer behaviour. These consumer behaviour models take a bottom-up approach to understanding the relative likelihood of different types of consumers to take-up different technologies, depending on a range of factors that influence their purchasing decisions. These factors include the economic proposition – capital costs and on-going costs – the suitability of the technology, for example the varying suitability of heat pumps to different house types and also consumer attitudes toward different technology choices, for example their view of the 'hassle' associated with a particular technology choice. Established consumer choice modelling techniques can then be used to predict the rate at which different types of consumers will take up the various options they are presented with. A generalised schematic of this kind of consumer choice model is shown in the figure below.

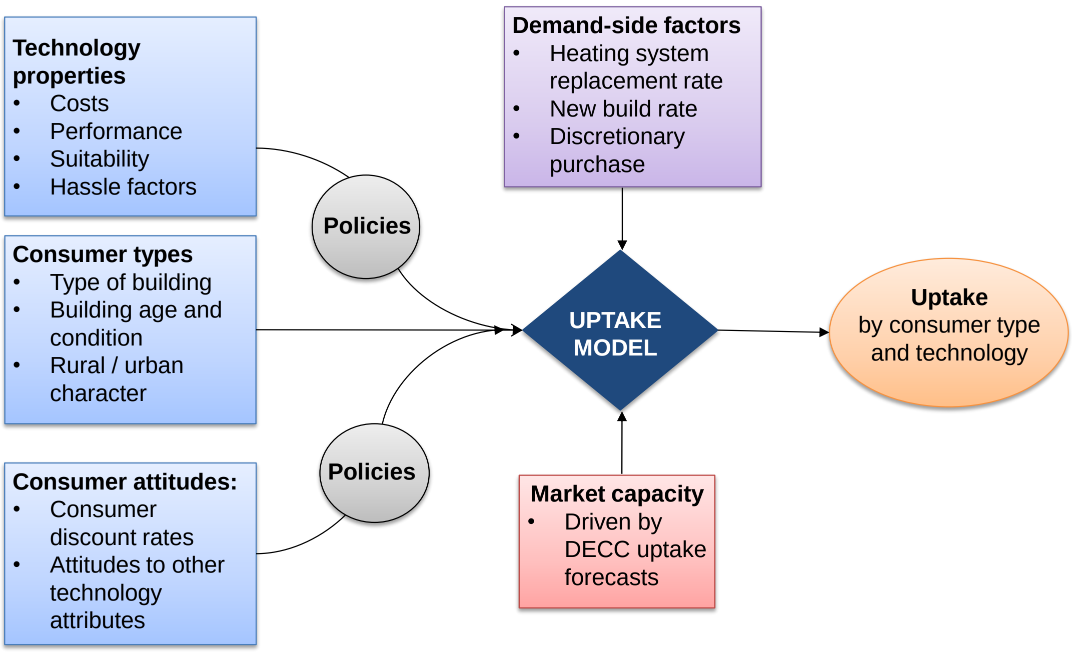


Figure 3.8 Schematic overview of a generalised consumer uptake model (Source: Element Energy)

The approach combines data on the attributes of technologies, the attitudes and investment behaviour of consumers together with demand and supply-side factors to forecast uptake by different consumer types.

A number of consumer behaviour models of this type have been developed by Element Energy to understand the impact of particular policies, such as the feed-in tariff and renewable heat incentive, on the uptake of low carbon technologies[21,22]. In this work, the overall levels of uptake are taken as inputs, based on the DECC scenarios described in the preceding sections. Consumer behaviour models have therefore been used to derive an understanding of the relative differences in the rate of uptake of technologies between the different consumer types, where the consumers are characterised by the different building types that are connected to LV networks[23] (see Section 4 and Appendix C for a discussion of the basic building types that make up the load on LV feeders). Given the rates of uptake of each technology by building type generated by this approach (for each technology and each GB-wide uptake scenario) and the analysis of the regional composition of the building stock derived from published data, it is possible to generate a set of regionally specific uptake curves for each technology and for each scenario.

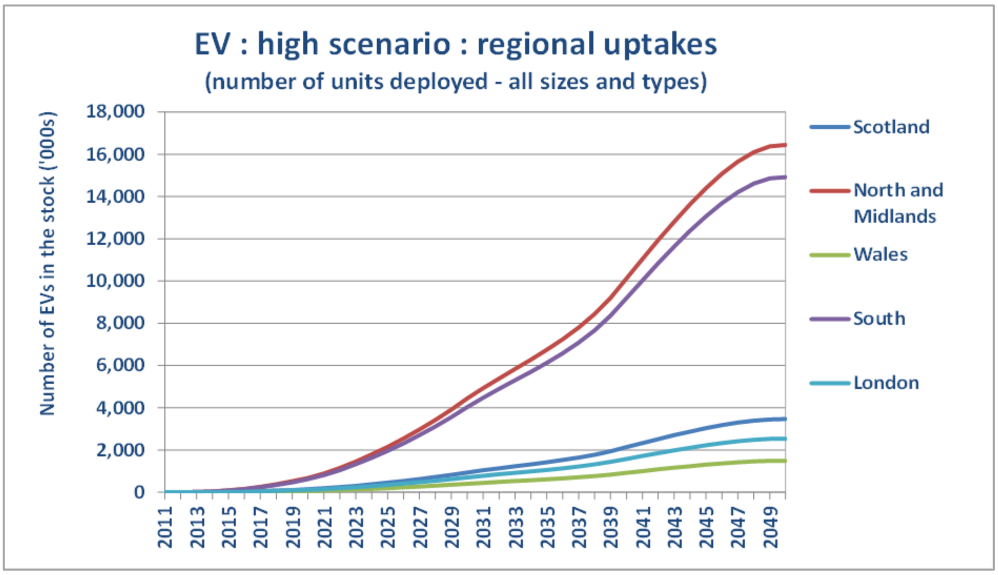


Figure 3.9 Regional disaggregation of electric vehicle uptake (High scenario) (Source: Element Energy)

The consumer behaviour modelling approach described above allows the impact of various policies on investment decisions to be represented. Where known, regionally specific policies can be implemented, for example the impact of congestion charging exemption for electric vehicles in London. There may be other regional factors that influence where technology uptake occurs in the future, for example local planning policies, which the modelling is not able to predict.

3.2.8 Uptake at LV network level

The second stage of the regional disaggregation is to consider how the connection of new technologies might be distributed across the LV networks, on the basis of the types of customers that are connected to those networks. In total, nineteen LV network types have been defined (including radial and meshed variants) that are associated within the model with different kinds of HV networks. These HV networks and therefore the LV networks connected to them are associated to areas of different rural / urban character, with corresponding assumptions regarding the density of customers connected. A highly detailed analysis has been undertaken to define, on average, the number and mix of customers on each of the LV network types (i.e. the number of domestic

[21] Design of feed-in tariffs for sub-5MW electricity in Great Britain, Element Energy, July 2009.
[22] Achieving deployment of renewable heat, Element Energy and NERA, 2011.
[23] In the case of electric vehicles the consumers are based on data generated from a large-scale survey of new car buyers, segmented on the basis of expressed attitudes and the rural, suburban or urban designation of their home addresses.

connections of different house types and number of non-domestic connections) for each of the five regions (this analysis is described in detail in Section 4 and Appendix B).

Based on the rates of uptake by building type for each technology and within each of the regions, coupled to the building mix on each LV network and statistics on the relative frequency of each network type within the overall LV network (regionally specific), it is possible to derive a rate of penetration of each technology into each LV network for each region. An example is shown below for the uptake of heat pumps in a selection of LV network types.

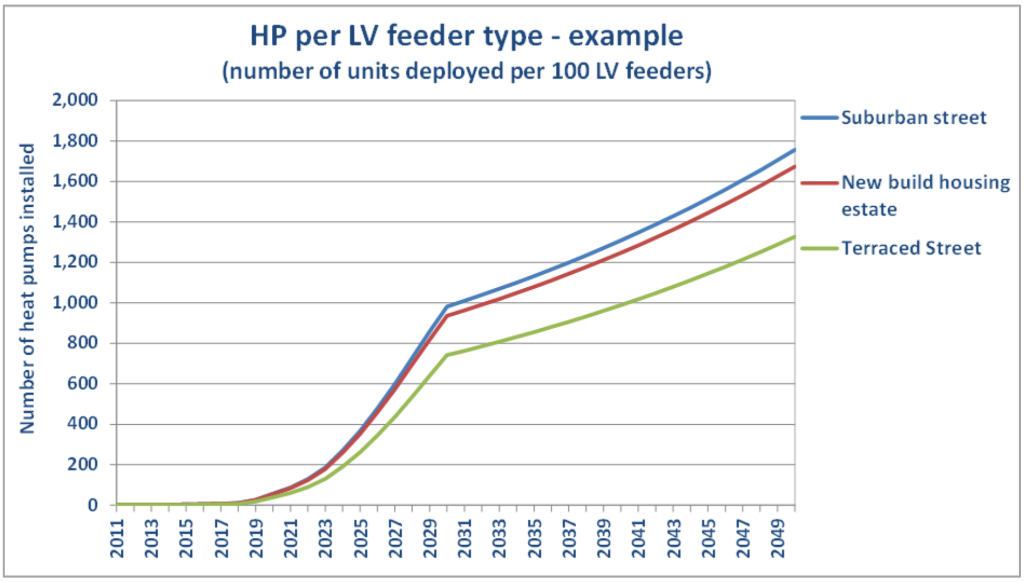


Figure 3.10 Example of the disaggregation of technology uptake to the level of individual LV network feeders (Source: Element Energy)

The rate of heat pump penetration into a selection of suburban residential feeders is shown (the number of heat pumps installed per 100 feeders is plotted); this provides the basis for a highly granular analysis of the impact of the over-arching rates of technology uptake on load on different parts of the LV network, for example the rate of load growth on rural networks compared to suburban residential or town centre networks and how this is likely to drive investment can be forecast.

3.3 Clustered forecasts for low carbon technologies

The preceding sections have described the approach taken to disaggregating national level uptake scenarios to the regional level and then to forecast within those regions, the different rates of connections expected to be seen on different types of LV network. These different rates of uptake are driven by a set of rational factors regarding regional differences, investment behaviour of consumers and suitability of technologies to the different building types found on different types of LV network.

In reality, it is likely that LCTs will cluster in certain areas due to less rational factors, leading to significant demand increases in these areas and hence significant network investment. Indeed, one relatively small cluster of LCTs could drive more investment than the deployment of ten times the number of technologies across a slightly broader network area. It is therefore important that the model understands the likely clustering levels and apportions LCT connection across networks in this manner.

A good example of this is the adoption of PV over recent years. The Feed-in Tariff (FiT) exists across the country, but the uptake of technology has been far from uniform. Figure 3.13 shows the normalised number of domestic PV installations by Local Authority. It is clear that certain areas are experiencing far more rapid take-up of the technology than others. This could be as a result of 'rational' or 'irrational' clustering. An example of rational clustering of PV would be in a geographic area where the conditions are best for maximum output from the generator (such as the south west of England, perhaps). An example of irrational clustering would be when several homeowners along a street decide to invest in PV because one of their neighbours has and they wish to be seen to be 'keeping up with the Jones''. While the approach described in preceding sections is an attempt to model the development of rational clustering, the model also needs to assess the extent to which irrational clusters could drive investment.

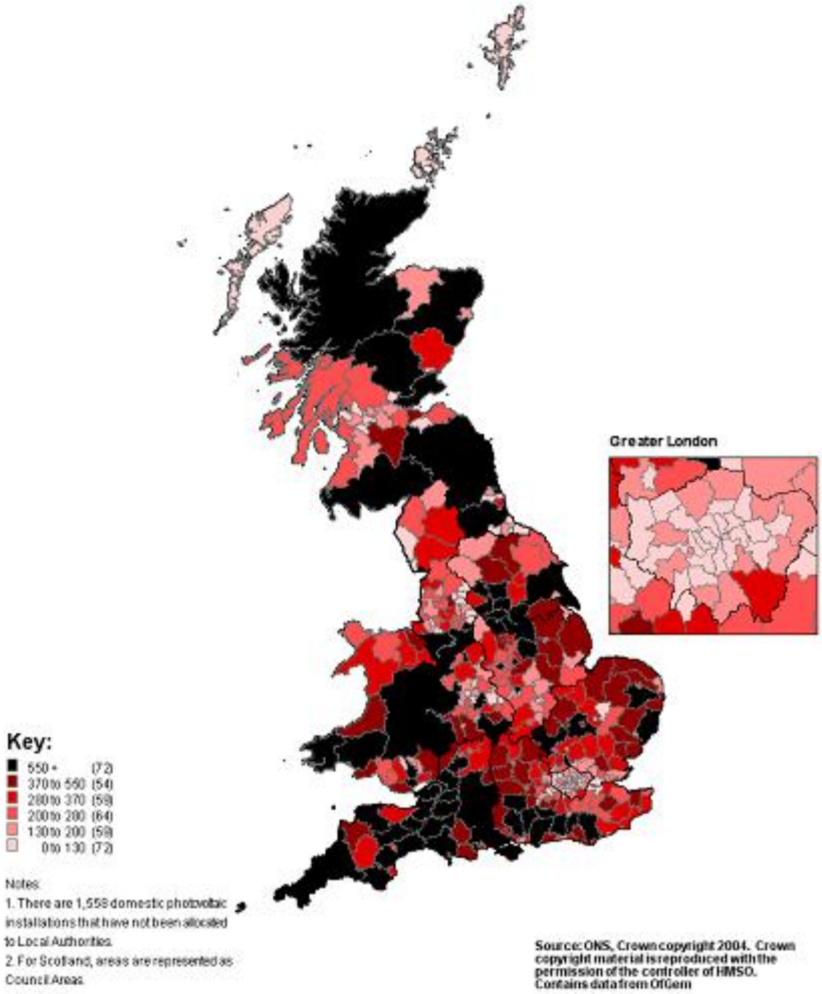


Figure 3.11 Number of domestic PV installations per 10,000 households by Local Authority, end of December 2011 (Source: Ofgem)

Analysis has revealed that as of the latest Ofgem FiT report, approximately 9% of all PV installations have occurred in less than 1% of the available LV network, as shown in Table 3.3 below.

Table 3.3 Spread of low carbon technology installations to networks

Percentage of network	Percentage of low carbon technology installations

1%	9%
4%	17%
25%	48%
30%	22%
40%	5%

In order to account for this, the model has ten ‘cluster groups’, ranging from highly clustered to weakly clustered. LCTs are apportioned within these groups according to the levels of clustering set within the model. As a starting assumption (and in the absence of any other data) the clustering of PV, electric vehicles and heat pumps are all set to mirror the clustering of PV observed through the FiT data.

This is, however, fully customisable per LCT and as and when more detailed information becomes available, the model can be updated with these revised figures. Figure 3.12 demonstrates the effect that clustering has on the uptake of LCTs in small portions of the network for a zero clustering, FiT clustering and high clustering scenario.

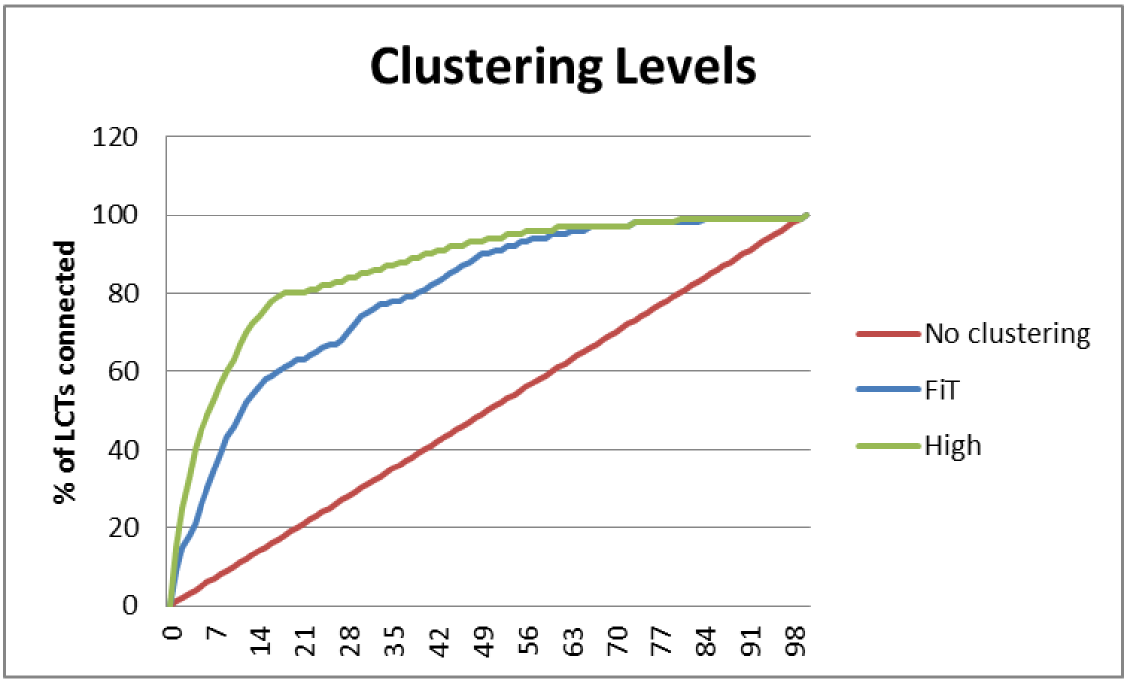


Figure 3.12 Clustering levels - % of LCTs connected

4 Development of updated representative networks

In this section, we provide an overview of the process by which the parameter-based model of the GB distribution system has been constructed. We discuss the parameters that have been quantified, the data sources used and the assumptions that were made. We also examine the way in which the starting load profiles were determined. These profiles give the base case for GB demand at distribution level and it is on these foundations that the impact of new technologies, and hence the need for interventions to release headroom, are based.

4.1 Overview of representative networks

When considered in isolation, one portion of network can vary considerably from another. However, upon closer inspection, networks exhibit certain traits that can be characterised by a number of parameters.

For example, an LV network in a city centre will be composed exclusively of underground cables; generally of large cross-sectional area, they are fairly short in length (as all of the demand is focused in a small area) and supplied by large ground mounted transformers. Whether the network operates in a radial or interconnected manner will determine the actual conductor size and the likely distance between substations. A rural network, by contrast, will often be overhead construction, with longer circuits to reach customers in a lower density area, supplied by small, pole mounted transformers.

Further to these characteristics, certain networks are likely to be of older build, such as those in town centres or suburban areas populated with an old building stock, such as 1930s semi-detached properties. Others will be of different design having been constructed much later (a 1990s housing estate, for example).

By looking at networks in this way, it is possible to characterise the very large number of feeders in existence across the country into a much smaller, and hence more manageable, number of feeders for modelling purposes. A list of these feeders is presented in the following three tables.

Table 4.1 EHV network feeders

Network	Geographical Area	Customer Density	Network Construction	Topology
EHV 1	Urban	High	Underground	Radial
EHV 2	Urban	High	Underground	Meshed
EHV 3	Suburban	Medium	Mixed	Radial
EHV 4	Suburban	Medium	Mixed	Meshed
EHV 5	Rural	Low	Overhead	Radial
EHV 6	Rural	Low	Mixed	Radial

Table 4.2 HV network feeders

Network	Geographical Area	Customer Density	Network Construction	Topology
HV 1	Urban	High	Underground	Radial
HV 2	Urban	High	Underground	Meshed
HV 3	Suburban	Medium	Underground	Radial
HV 4	Suburban	Medium	Underground	Meshed
HV 5	Suburban	Medium	Mixed	Radial
HV 6	Rural	Low	Overhead	Radial
HV 7	Rural	Low	Mixed	Radial

Table 4.3 LV network feeders

Network	Geographical Area	Customer Density	Topology
LV 1	Central Business District	High	**Radial**
LV 2	Dense urban (apartments etc.)	High	**Radial**
LV 3	Town centre	High	**Radial**
LV 4	Business park	Medium	**Radial**
LV 5	Retail park	Medium	**Radial**
LV 6	Suburban street (3 / 4 bed semi or detached houses)	Medium	**Radial**
LV 7	New build housing estate	Medium	**Radial**
LV 8	Terraced street	High	**Radial**
LV 9	Rural village (overhead construction)	Low	**Radial**
LV 10	Rural village (underground construction)	Low	**Radial**
LV 11	Rural farmsteads / small holdings	Very low	**Radial**

LV 12	Central Business District	High	**Meshed**
LV 13	Dense urban (apartments etc.)	High	**Meshed**
LV 14	Town centre	High	**Meshed**
LV 15	Business park	Medium	**Meshed**
LV 16	Retail park	Medium	**Meshed**
LV 17	Suburban street (3 / 4 bed semi or detached houses)	Medium	**Meshed**
LV 18	New build housing estate	Medium	**Meshed**
LV 19	Terraced street	High	**Meshed**

It should be noted that, to allow flexibility within the model, it is possible to have 8 EHV, 8 HV and 20 LV feeders. While the feeders have been chosen such that they represent the vast majority of the GB network, there will be some cases that are not identically mapped to one of the given types. Examples may include sub-sea 33kV cables, or feeders that supply direct transformation sites from 132kV to 11kV. The "spare" feeder types are provided to allow users of the model to populate additional characteristics relating to a feeder that may not be currently covered by the existing modelled feeders.

Once these standard feeders had been agreed upon, data was sought from all Network Operators to establish the representative LV, HV and EHV feeders to be constructed. Figure 4.1 demonstrates some of the analysis carried out in quantifying the average length of HV feeders in different network areas; having first established boundaries regarding the criteria for an "urban", "suburban" or "rural" area.

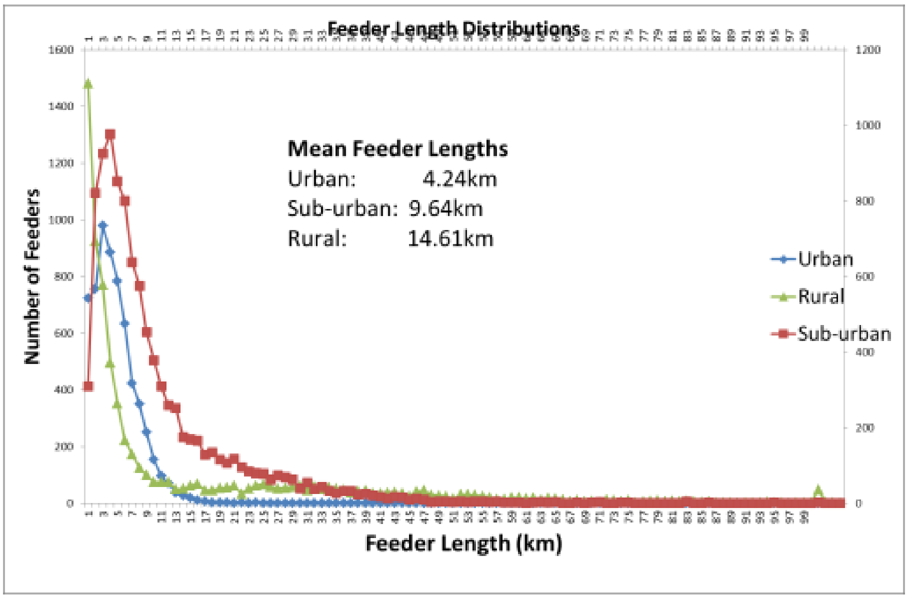


Figure 4.1 Quantifying the average length of HV feeders in different network areas

The lengths discussed above are 'total electrical lengths', but the parameter of interest within the model is the 'main feeding length'. In order to determine this length, analysis was undertaken to establish a 'branching' factor for different network types. This provides an averaged view of the likely proportion of a feeder that is in the 'main' length (particularly important when considering the voltage drop along a feeder). Table 4.4 shows how these branching factors were applied to the seven HV feeder types within the model.

Table 4.4 Application of branching factors to HV feeder types

Network	Geographical Area	Customer Density	Network Construction	Topology	Total length (km)	Branched factor	Main length (km)
HV 1	Urban	High	Underground	Radial	4.23	0.9	**3.8**
HV 2	Urban	High	Underground	Meshed	2.79	0.9	**2.5**
HV 3	Suburban	Medium	Underground	Radial	4.62	0.8	**3.7**
HV 4	Suburban	Medium	Underground	Meshed	2.70	0.8	**2.2**
HV 5	Suburban	Medium	Mixed	Radial	15.04	0.7	**10.5**
HV 6	Rural	Low	Overhead	Radial	40.60	0.46	**18.7**
HV 7	Rural	Low	Mixed	Radial	18.00	0.55	**9.9**

4.2 Feeder loads and feeder load profiles

With the parameters established, the next step was to address feeder loads and profiles. Whilst data regarding EHV and HV networks is fairly readily available, DNOs had to be approached directly to obtain data on their LV networks. The definition of standard LV feeder loads developed from this data analysis, where the standard feeder loads are the combinations of the basic house types and non-domestic building types associated with the 19 LV networks, is summarised in Figure 4.2 below.

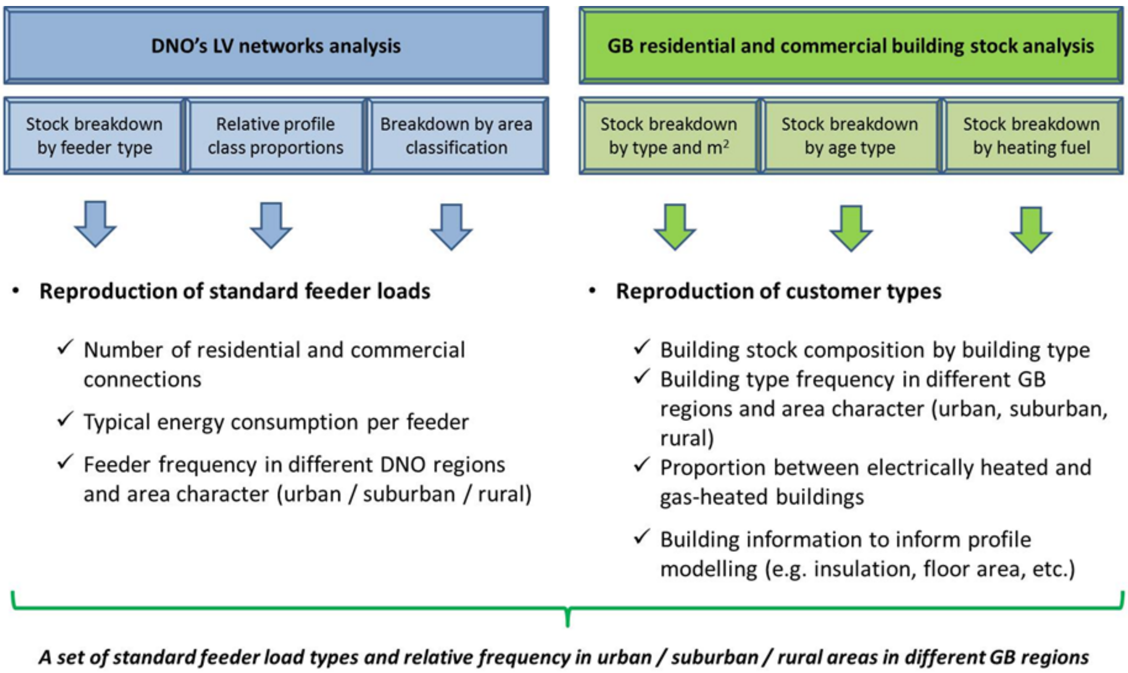


Figure 4.2 Definition of standard LV feeder loads (Source: Element Energy)

A set of LV feeder loads have been defined for each region and for areas of differing urban / rural character within each region. A distinction between existing feeders and new build feeders has also been made. As described in the schematic above, there are two main components to the analysis underpinning the definition of standard feeder loads. The first strand of the analysis involved assessment of a large quantity of data provided by the DNOs, detailing the connections to their LV feeders in terms of the number and mix of customer. The DNO data on the type of connection is in terms of profile class 1 to 8 or as a half-hourly connection, but gives no insight into the types of buildings connected, e.g. the mix of house types or non-domestic premises. The second strand of the analysis was then undertaken to develop an understanding of the composition of the building stock at a regional level, as a means of populating the standard feeder loads with a representative mix of building types. This second stage of the analysis was based on data on the housing stock contained with the English, Scottish and Welsh House Condition Surveys and data from the Valuation Office Agency on the non-domestic floor space by local authority area.

The standard feeder load types when combined in appropriate proportions allow the model to accurately represent the composition of the building stock in each of the regions and areas of different urban/rural character within those regions, for example the greater proportion of detached houses in rural and suburban conurbations, terraced homes in suburban areas and higher density of flats in urban conurbations. A comparison of the modelled housing stock breakdown with data provided by the House Condition Surveys and DNOs is shown in Figure 4.3, below.

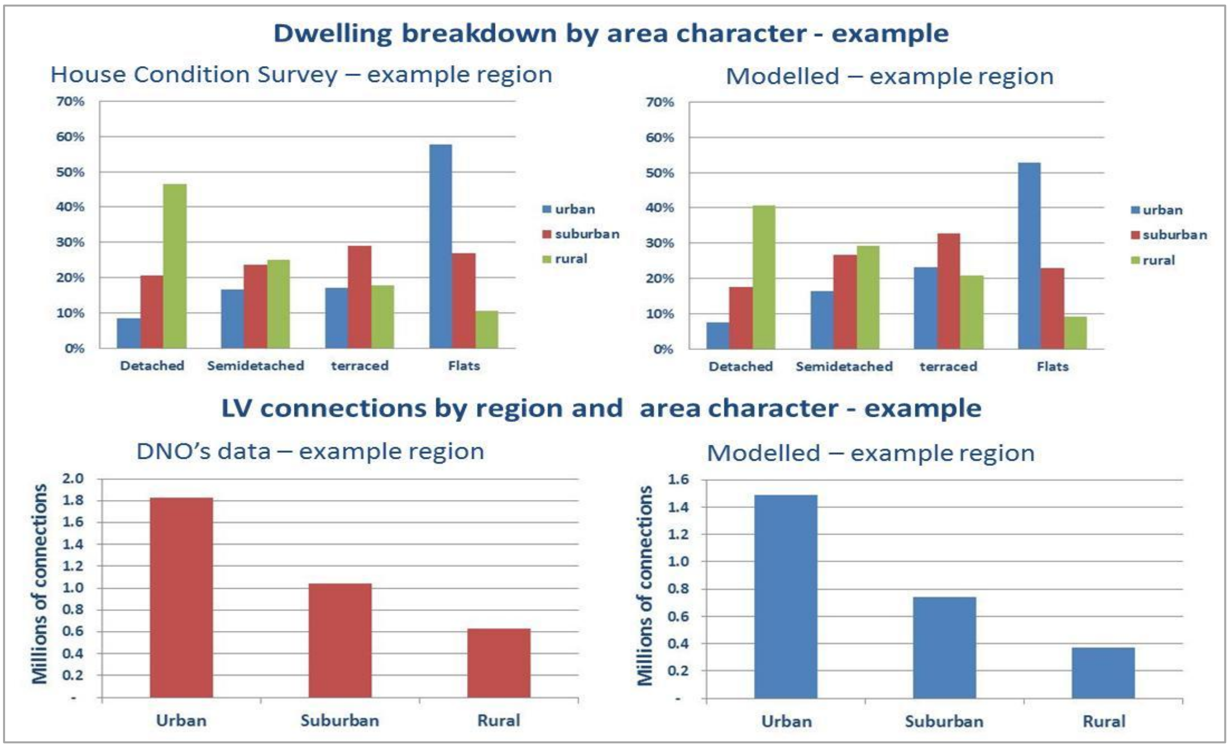


Figure 4.3 **Dwelling breakdown by area character – example (Source: Element Energy)**

4.3 Building loads

In order to accurately calculate the half hourly demand profiles for the 19 different LV feeder types within the WS3 model, it was necessary to develop a set of individual point loads for different building types. This led to profiles being generated for 17 domestic building types and 8 non-domestic types. Demand profiles at this high level of granularity are required for a number of reasons as follows:

- The demand profile varies significantly between building types, depending on factors such as size, age, construction, building use and occupancy
- Different buildings have different potential for uptake of LCTs
- Different potential for DSR in each building type due to the different appliance populations

Figure 4.4 is an overview of the process for estimating LV feeder demand profiles. The various individual profiles for each point load type (shown on the left) are aggregated based on the number of each point load type present on each feeder to generate the load profile on the right. The profiles were generated on an annual basis (2012 – 2050) for three representative days: winter peak, winter average and summer average (consistent with Work Stream 2).

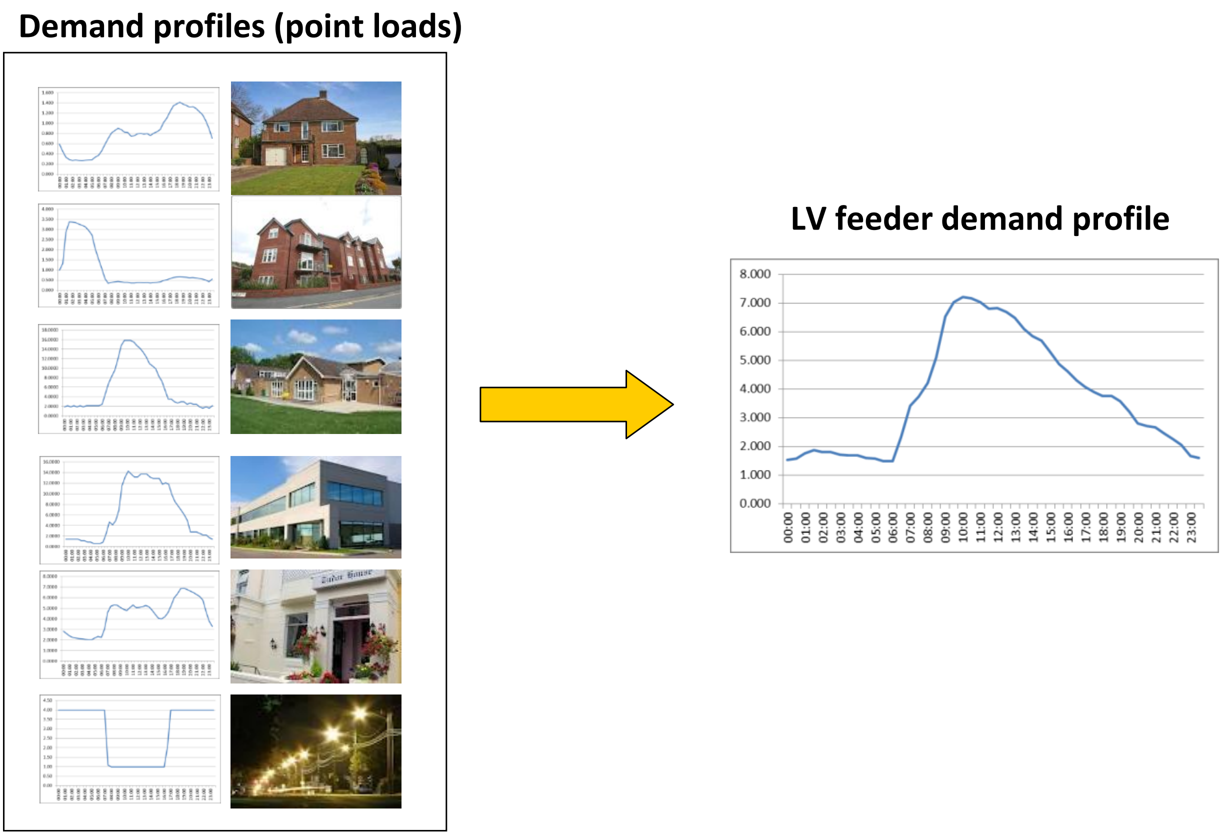


Figure 4.4 LV Feeder Loads (Source: GL Noble Denton)

The loads are disaggregated such that the proportion of load attributed to heating, lighting, cooking etc. is known. This is important as, over time, energy efficiency improvements mean certain loads are likely to significantly reduce. This disaggregation therefore allows the future demand of each building to be captured, but it also allows for the proportion of the load that will be amenable to DSR to be calculated. This is because some loads cannot be shifted (lighting, for example) while others, such as that associated with wet appliances, could be shifted with the roll-out of smart appliances.

Figure 4.5 demonstrates the average (i.e. fully diversified) load associated with a sample house during winter 2012, split by load type (excluding any electric heating).

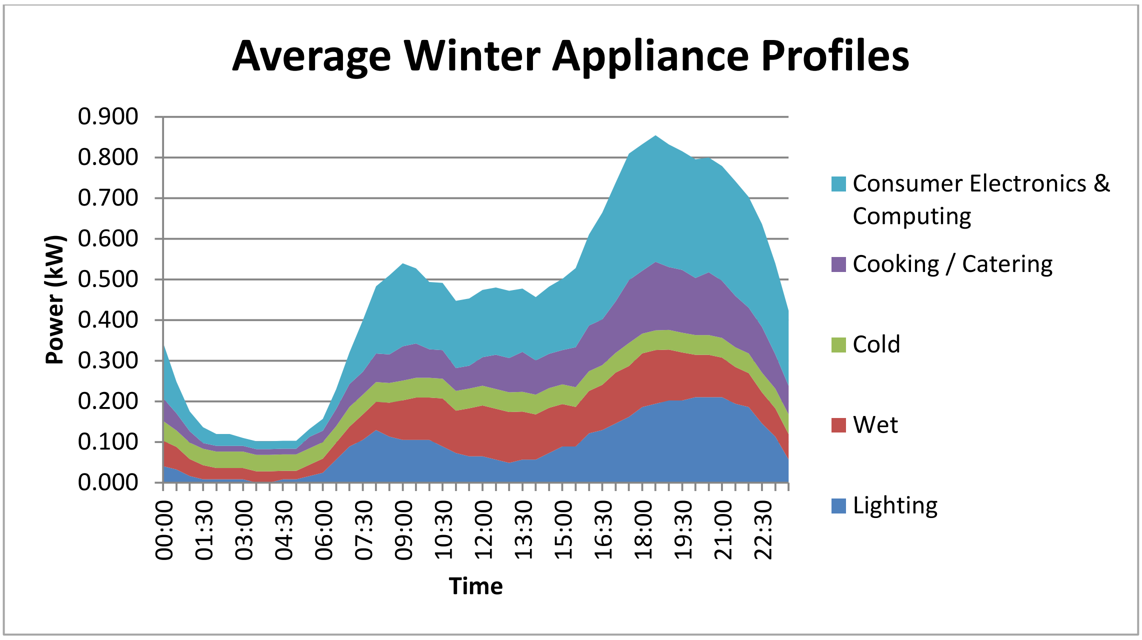


Figure 4.5 Domestic profile disaggregated by appliance (Source: GL Noble Denton)

4.3.1 Domestic space heating profiles

Fully diversified electricity demand profiles were generated for each building type for three different electric heating systems:

- Direct acting resistive heaters
- Storage heaters (Economy 7)
- Heat pumps

For the case of summer average, it is assumed that there is no heating demand. In order to generate average and peak winter heating demands, simulations were run at external temperatures of -5°C and +5°C, with an average room set temperature of 18°C. This range of external temperatures is assumed to cover the range of peak and average winter temperatures which occur in different regions of the UK. Heating profiles at specific temperatures in this range can be calculated by interpolating between the two set of profiles. In order to allow incorporation into the WS3 model the heating profiles were averaged across all domestic building types to produce average profiles.

There is some debate over how users will operate heat pumps. It has been suggested that they may run in a continuous manner and, indeed, this mode of operation would also help mitigate the peak demands in early morning and evening as many heating systems start up. Only very limited heat pump field trial data was available for this study, but this showed heat pumps operating in an intermittent manner. This presents a worse case for network operators as the heat pump will be running at a higher level of demand at times when demand is already higher than average and this behaviour was assumed within the model.

Some heat pumps are equipped with storage and these devices allow demand to be moved for short periods without compromising the heating of the building. The proportion of heat pumps present on the network that are equipped with this functionality is expressed as a percentage within the model and can change from year to year.

4.3.2 Domestic PV profiles

Three profiles (one for each of the representative days) were generated for a PV installation with 3.8kWp output. This corresponds to a large domestic installation and so is scaled down when applied to smaller properties due to restricted roof space. These profiles represent the generation expected from a single PV installation and so are not diversified. Given that an individual LV feeder will cover a limited geographical area, there will be little, if any diversification i.e. all panels will be experiencing similar levels of incident solar radiation.

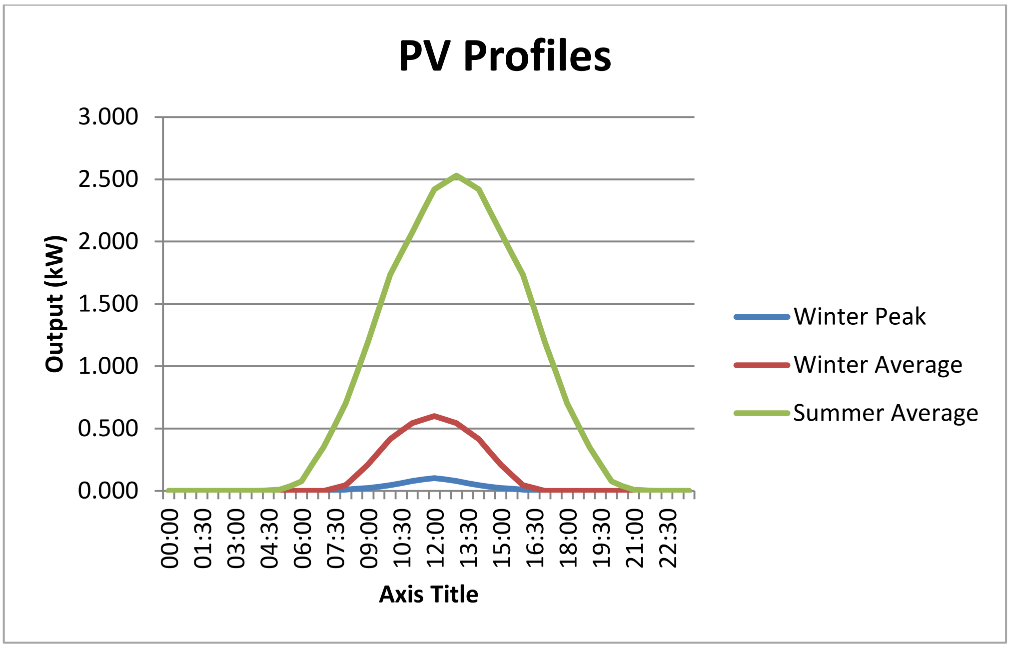


Figure 4.6 Domestic PV profiles (Source: GL Noble Denton)

These profiles were generated based on a sample of two years of radiation data.

4.3.3 Non-domestic buildings

Similar analysis was carried out for non-domestic buildings to establish the electricity consumption attributable to different elements of demand (lighting, heating, cooking etc.). The profiles generated were validated against Elexon profiles to ensure consistency, and were then fed into the overall feeder load models in the appropriate proportions to define the mix on the various feeders of domestic and commercial load.

4.4 Diversity

The individual demand profiles generated by GL Noble Denton represent fully diversified profiles (with the exception of the street lighting and PV profiles which should not be diversified). The diversity is a direct result of the fact that 3,000 simulations have been run for each building type. However, when combining profiles at the LV feeder level where there are a relatively small number of consumers, peak loads will be higher than the diversified profiles suggest because the diversity acts in the same way as a smoothing filter, representing the average load, but removing the peaks that may be observed. Figure 4.7 illustrates the smoothing effect of diversity by comparing the demand profile of one home to that of many homes that have been fully diversified.

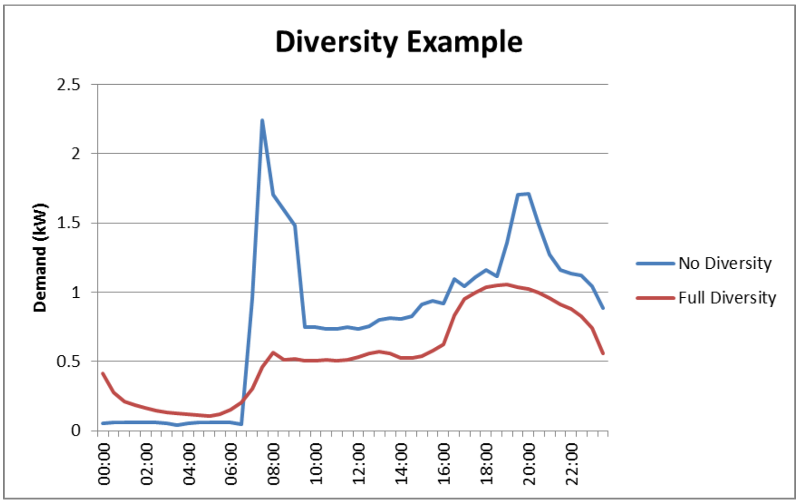


Figure 4.7 Example of Diversity: One house vs. many (Source: GL Noble Denton)

Therefore certain profiles within the model (those associated with LV feeders having a considerable amount of domestic load) have had their profiles scaled to account for this reduction in diversity. At higher voltages, and for commercial loads, this is less of an issue as diversity tends to be representative of the overall load. However when dealing with a relatively small number of properties along a feeder, the behaviour of the load associated with merely one or two of these properties can have a significant effect on peak demand. Such feeders have therefore had their loads scaled by a factor of 1.4 to account for this. This factor aligns with common DNO practice today.

4.5 Feeder Composition

The detailed LV network analysis resulted in the identification of a set of standard LV feeder loads - the basic building blocks from which a representation of the LV network can be constructed. In this manner, the current and future loads at LV can be modeled from the bottom-up.

The analysis produced a set of standard feeders fully characterised in terms of:

1. Number of connections on the feeder (by region and area character)
2. Type of buildings served by the feeder (by region and area character)
3. Estimated Annual energy Consumption (EAC)
4. Relative frequency of the different feeder types across different GB regions and area character (urban/suburban/rural)

When combined with the work to calculate the building load profiles, it was possible to model the typical combined load profile imposed on the different feeders in different regions of GB. Furthermore, through the detailed analysis of the DECC scenarios (defined under Work Stream 1), it became possible to disaggregate these national scenarios for the uptake of LCTs down to the individual representative feeder level and so forecast how technology uptake will drive load growth in each of the representative feeder types (an example is shown in Figure 4.8, below).

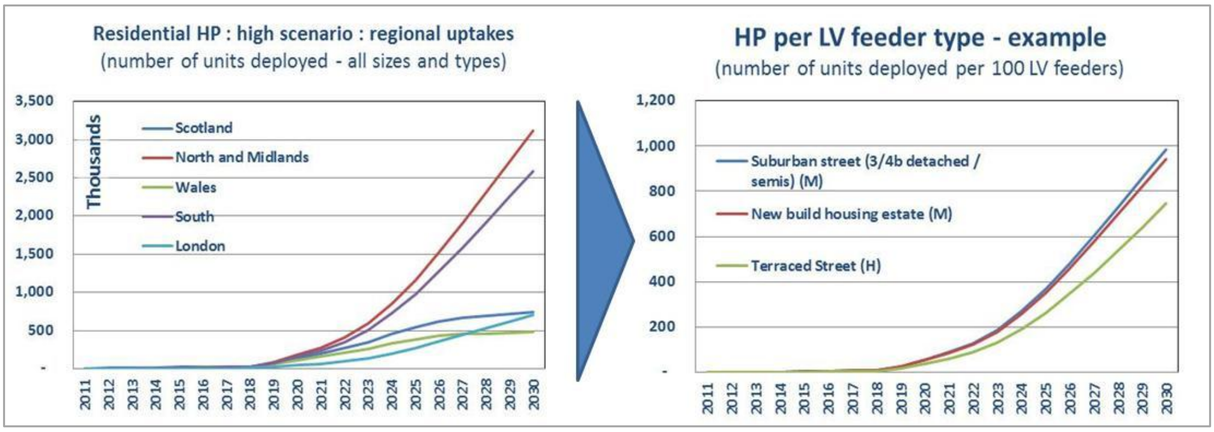


Figure 4.8 Residential HP regional uptakes to HP per LV feeder type – example (Source: Element Energy)

Finally, as the work undertaken to define standard feeder loads preserved information on the numbers of feeders and relative populations of the different feeder types within different GB regions and areas of different character (urban / suburban / rural) within each region, it was possible to reconstruct regional and national level uptake of LCTs from the bottom-up level of the individual LV feeder types.

4.6 Matrix of 'typical' network topology types

It is worth recapping here that under Work Stream 2, three LV, one HV, and one EHV networks were modelled. This resulted in three possible "network combinations" with the single EV feeding the single HV which, in turn, supplied one of the three LV feeders. Under WS3, six EHV, seven HV and 19 LV feeders are modelled, giving a total of 798 potential combinations. For each feeder we define length, rating, customers connected, and load. This is based on extensive analysis of DNO networks, together with bottom-up analysis building LV feeders from MPANs by location.

However, in practice not all of these combinations are feasible. For example, one could not envisage a situation where a rural overhead line at EHV feeds a dense urban environment at HV, which in turn feeds farmsteads and small holdings at LV. Through discussion with the steering group of Network Operators, the feasible combinations were identified, which reduced the possibilities from 798 to 100. Figure 4.8, below, shows an example of how the feeder types could be linked by looking at the likely feeders supplied at HV and LV, stemming from an initial supply from an EHV feeder type 3.

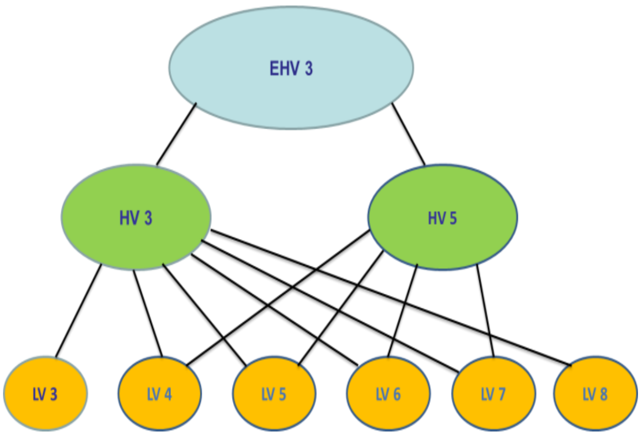


Figure 4.8 Network topology example

Within each of these matrices, the apportionment of feeder types is specified. For example, in the above case, it is necessary to specify what proportion of HV feeders supplied by EHV 3 can be categorised as HV 3 as opposed to HV 5. The relative numbers of each of the LV feeder types supplied from both HV 3 and HV 5 are then also defined.

This exercise has been carried out for the GB-wide model, with care taken to ensure that the total number of feeders at EHV, HV and LV aligns with the total number of feeders present in the GB electricity distribution system. The apportionment has, through necessity, been carried out with a series of assumptions as the granular data regarding precisely how many LV feeders of one specific type as against another are fed from a given HV feeder is not readily available. However, in order to ensure that the figures chosen are reasonable, a number of sensitivity tests have been run, together with a range of checks against available data relating, in particular, to EHV and HV feeders.

4.7 Review of assumptions

A number of assumptions have been taken with regard to defining the representative feeders. Some of these have been based on fairly detailed analysis of data, while others have been arrived at through discussion with the DNO group. Several have relied on experience and engineering judgement to allow the production of a representative GB-wide model.

Some of the key assumptions are captured in the table below while further detail regarding the methods used for characterising feeders at LV, HV and EHV can be found in Appendix B.

Table 4.5 Key assumption areas when defining feeders and loads

Subject	Assumption basis
Number of EHV feeders	DNO Long Term Development Statements (LTDS)
Number of HV feeders	Data from DNO IIS return
Number of LV feeders	Data from representative number of DNOs, scaled to GB level
EHV feeder length	Data from DNOs and LTDS
HV feeder length	Data from DNOs
LV feeder length	Knowledge and experience of EA Technology together with limited data from DNOs
Branching factor for feeders	Analysis of a number of feeders from several DNOs to determine average factors for different feeder types, backed up by knowledge and experience of EA Technology
EHV feeder rating	Data from limited number of DNOs together with LTDS
HV feeder rating	Knowledge and experience of EA Technology together with limited data from DNOs
LV feeder rating	Knowledge and experience of EA Technology together with limited data from DNOs
Matrix of representative networks	Discussion and agreement with DNO group
Number of EHV feeders that fall into each class	Knowledge and experience of EA Technology

Number of HV feeders that fall into each class	Analysis of DNO IIS data
Number of LV feeders that fall into each class	Comprehensive bottom-up analysis of LV data for several DNOs scaled to GB level
Proportion of HV feeders supplied by representative EHV feeders	Knowledge and experience of EA Technology with numbers reconciled against total GB feeder numbers
Proportion of LV feeders supplied by representative HV feeders	Knowledge and experience of EA Technology with numbers reconciled against total GB feeder numbers
Average number of HV feeders supplied by each EHV feeder	Knowledge and experience of EA Technology with numbers reconciled against total GB feeder numbers
Average number of distribution substations supplied by each HV feeder	Knowledge and experience of EA Technology and discussion with DNO group
Average number of LV feeders supplied from each distribution substation	Knowledge and experience of EA Technology with numbers reconciled against total GB feeder numbers
Definition of boundaries for urban/suburban and suburban/rural	Analysis of load density for feeders of different types coupled with the previous knowledge of EA Technology
The ratio of overall DG connected at EHV/HV/LV	Data from DUKES with engineering judgement regarding the maximum generator size that would be found at LV and HV
The apportionment of DG connections by feeder type	Engineering judgement (e.g. the majority of wind at HV is in rural areas as opposed to urban and suburban etc.)

5 Characterisation of conventional and smart interventions

In this section, we provide an overview of the solutions that have been applied in the model and of the methodology used to select different solutions in resolving network constraints.

5.1 Overview

By applying the low carbon scenarios to the parameterised networks, it is possible to understand how the thermal capacity, voltage and fault level headroom limits change over time. When headroom is reduced to a pre-set trigger point limit, the model seeks to deploy a solution that will resolve the problem. We consider two types of solution:

- **Smart**: New solutions, these can be technological and commercial, and operating on the network-side, generation-side or customer-side of the Value Chain. Where possible, solutions have been linked to projects in development through the Low Carbon Network (LCN) Fund or Innovation Funding Incentive (IFI) Regulatory mechanisms.
- **Conventional**: Those solutions that are widely used in the design, operation and management of networks today. The solutions outlined in this report have been agreed as typical amongst the GB network operators as part of this project.

It should be noted that under the "business as usual" investment strategy, only conventional solutions will be available, while under the two smart investment strategies, they will be available along with the smart solutions. This is in recognition that many of the smart solutions can defer investment, but in some instances, they may not be able to fully resolve capacity issues for the long-term.

5.2 Representative Solutions, Variants and Enablers

With the potential range of solutions available to networks, it has been necessary to agree upon a common language:

- **Representative Solutions**: The broad class of solution. Examples of Representative Solutions include: New feeders, Demand Side Response (DSR); Real Time Thermal Rating (RTTR); Electrical Energy Storage (EES)
- **Variant Solutions**: The more specific versions of a solution, accounting for differences in connection voltage, asset type, customer classes, etc. They have been drawn out as variants of the representative solution as they have different parameters, e.g. cost, headroom release, loss impact, etc. Variant examples include:
  - New feeders – Split LV feeder, Split HV feeder, etc.
  - DSR –DNO led commercial (via an independent aggregator) DSR, etc.
  - RTTR – HV overhead line RTTR, LV underground cable RTTR, HV/LV transformer RTTR, etc.
  - EES – HV large EES, LV street level EES, LV residential customer level EES, etc.

Each Variant Solution is treated as an integrated system, recognising that in order to deliver a working solution, several individual technologies or components may have to be combined together. An example of a conventional system would be Automatic Voltage Control – the purchase of an AVC relay would need to be accompanied by measurements and transformer tap-changers in order to realise voltage headroom benefits.

- **Enablers**: An enabler is a component part of a solution, but one that is not, in itself, able to provide headroom benefits. They are typically associated with monitoring, communications or control systems. Two costs are captured in the model for enablers to account for differences in deployment on a holistic basis (top-down) and on a needs basis only (incremental). Examples of enablers included in the model are:
  - DNO to DCC communications – the ability for a DNO to link into the GB smart metering data via the Data and Communications Company (three variants of this enabler are included to reflect differences in function: 1-way data for planning purposes (e.g. downloaded every three-months); 1-way data to provide information on loads at certain times of day and/or signal loss of supply (30mins latency); 2-way communications to enact domestic Demand Side Response;
  - Power quality monitoring – the deployment of high accuracy measurement devices across the network (for example HV or LV feeder level) to assess the potential impact certain loads and forms of generation are having on the network.

Table 5.1 Summary of the numbers of Variant Solutions and Enabler technologies factored into the model

Solution Category	Conventional Solutions	Smart Solutions	Total
Representative solutions	5	15	20
Variant solutions	28	67	96
Enablers	-	30	30
Total:	**28**	**97**	**126**

A summary of all Variant Solutions and Enablers is provided in Appendix D, with more in depth datasheets in the supporting Annex on Detailed Solution Data.

5.3 Converting the WS1 Phase 1 Report to a Smart Solution Set

5.3.1 Background

The WS3 report "Developing Networks for Low Carbon - The Building Blocks for Britain's Smart Grids"[24], was the first formal deliverables of the Smart Grids Forum when published in October 2011.

[24]The link to the first report of Workstream 3 of the Smart Grids Forum can be found at: http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=18&refer=Networks/SGF/Publications

This report contained a qualitative assessment of the types of solutions that might feature in the future smart grid. It described two versions of smart grid solutions:

- **Smart Grid 1.0:** largely incremental improvements to the existing networks, through relatively local technologies, commercial contracts and approaches; and
- **Smart Grid 2.0:** more refined, integrated and holistic solutions, forging together different parts of the energy value chain in a coordinated manner

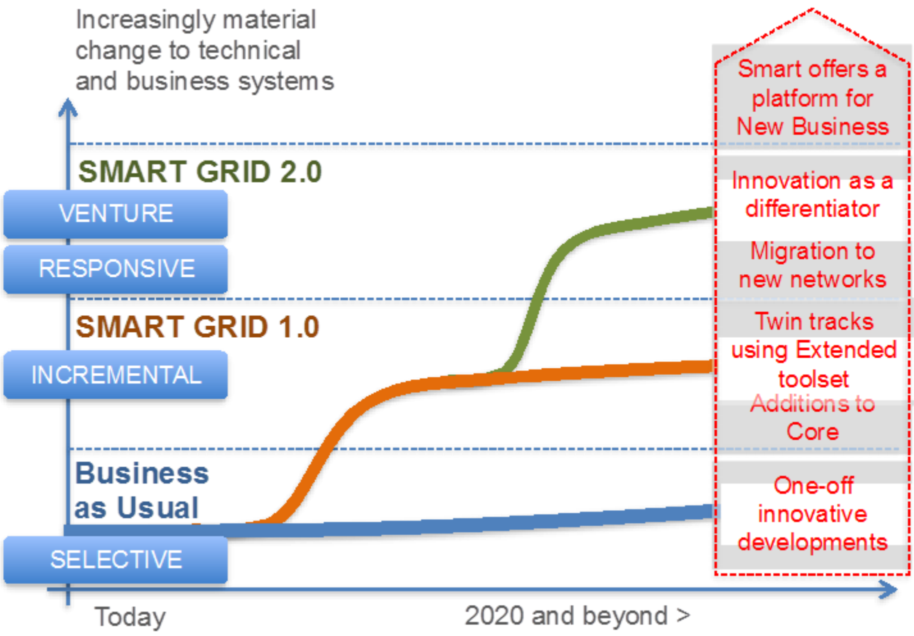


Figure 5.1 A Migration Path to Smarter Grids & New Business Models (Source: WS3 Phase 1 report)

A key output of the WS3 phase 1 report was the identification of potential solutions by the way of 12 'smart solution' groupings or sets, with an indication of the types of developments that might be required for both Smart Grid 1.0 and 2.0 (see Appendix D for a copy of this table):

1. Smart D – Networks 1 (supply and power quality)
2. Smart D – Networks 2 (active management)
3. Smart D – Networks 3 (intelligent assets)
4. Smart D – Networks 4 (security and resilience)
5. Smart T-Networks (enhancements)
6. Smart EV charging
7. Smart storage
8. Smart community energy
9. Smart buildings and connected communities
10. Smart ancillary services (local and national)
11. Advanced control centres
12. Enterprise-wide solution

In order to quantify the solutions contained within the above solution sets, it has been necessary to focus on some of the underlying technologies, commercial contracts or mechanisms that would be required to achieve the desired functionality. In mapping individual solutions to the 12 sets, there is a degree of cross-over, whereby one technology, for example electrical energy storage, could be applied to a range of solution sets (sets: 1, 2, 6, 7, 8, 9, 10 in this instance).

5.3.2 The Smart Solutions included in the model

The Smart Solutions included in the model are listed in Table 5.2. Further details, including the factors assigned to each solution, are provided in Appendix D and the accompanying Annex to this report.

Table 5.2 Overview of the Smart Solutions included in the Model

	Representative Solution	Description	Variants
1	Active Network Management - Dynamic Network Reconfiguration	The pro-active movement of network split (or open) points to align with the null loading points within the network.	• EHV • HV • LV
2	Distribution Flexible AC Transmission Systems (D-FACTS)	Series or shunt connected static power electronics as a means to enhance controllability and increase power transfer capability of a network	• STATCOM - EHV • STATCOM - HV • STATCOM - LV • Basic D-FACTS - EHV • Basic D-FACTS - HV • Basic D-FACTS - LV
3	Demand Side Response (DSR)	The signalling to demand side customers to move load at certain times of day. It is applicable to a broad range of customers, and giving benefits to different network voltages – hence the large number of variants.	• DNO to Central business District DSR • DNO to residential • DNO to aggregator led EHV connected commercial DSR • DNO to EHV connected commercial DSR • DNO to aggregator led HV commercial DSR • DNO to HV commercial DSR
4	Electrical Energy Storage	Electrical Energy Storage, e.g. large battery units, for voltage support and load shifting. Storage comes in all shapes and sizes, but the DNO is largely agnostic to the technology used. As the costs are currently expensive, several sizes of storage units have been included as variants.	• HV Central Business District (commercial building level) • EHV connected EES - large • EHV connected EES - medium • EHV connected EES - small • HV connected EES - large • HV connected EES - medium • HV connected EES - small • LV connected EES - large • LV connected EES - medium • LV connected EES - small
5	Embedded DC networks	The application of point-to-point DC circuits to feed specific loads (used in a similar manner to transmission 'HVDC', but for distribution voltages). A retrofit solution to existing circuits.	• EHV • HV • LV
6	Enhanced Automatic Voltage Control	A refinement to conventional automatic voltage control solutions (traditionally applied as far as the Primary busbars); with additional voltage control down the HV circuits and up to the customer cut-out in a dwelling.	• EAVC - HV/LV Transformer Voltage Control • EAVC - EHV circuit voltage regulators • EAVC - HV circuit voltage regulators • EAVC - LV circuit voltage regulators • EAVC - LV PoC voltage regulators
7	Fault Current Limiters	Devices to clamp fault current at time of fault, in order to maintain operation within the limits of switchgear.	• EHV Non-superconducting fault current limiters • EHV Superconducting fault current

			limiters • HV reactors - mid circuit • HV Non-superconducting fault current limiters • HV Superconducting fault current limiters
8	Generation Constraint Management	The signalling to generators to ramp down output at certain times of the year, or under certain loading / outage conditions.	• EHV connected • HV connected • LV connected
9	Generator Providing Network Support	Operation of a generator in PV (power and voltage) mode to support network voltage through producing or absorbing reactive power (VArs)	• EHV connected • HV connected • LV connected
10	Local intelligent EV charging control	An EV charging solution applied by the DNO to apportion capacity to several EVs on a feeder across a charging cycle.	• LV domestic connected
11	New Types Of Circuit Infrastructure	New types of overhead lines or underground cables. It is assumed that these circuit types will have a larger capacity than conventional circuits owing to improvements in current carrying capability.	• Novel EHV tower and insulator structures • Novel EHV underground cable • Novel HV tower and insulator structures • Novel HV underground cable
12	Permanent Meshing of Networks	Converting the operation of the network from a radial ring (with split points) to a solid mesh configuration.	• EHV • HV • LV urban • LV suburban
13	Real Time Thermal Rating	Increases to circuit or asset rating through the use of real-time ambient temperature changes and local weather conditions.	• RTTR for EHV Overhead Lines • RTTR for EHV Underground Cables • RTTR for EHV/HV transformers • RTTR for HV Overhead Lines • RTTR for HV Underground Cables • RTTR for HV/LV transformers • RTTR for LV Overhead Lines • RTTR for LV Underground Cables
14	Switched Capacitors	Mechanically switched devices as a form of reactive power compensation. They are used for voltage control and network stabilisation under heavy load conditions.	• EHV • HV • LV
15	Temporary Meshing (soft open point)	"Temporary meshing" refers to running the network solid, utilising latent capacity, and relying on the use of automation to restore the network following a fault	• EHV • HV • LV

It is extremely difficult (sitting in 2012) to predict the exact nature of solutions that will exist and be commonplace on the power system of the future. It is therefore recognised that the list of solutions will change over time, further improving the outputs of this model.

5.3.3 The Enablers to Solutions included in the model

The enablers in the model are listed in Table 5.3. Further details, including the factors assigned to each solution, are provided in the accompanying Appendix.

Table 5.3 Overview of the enablers included in the model

	Enabler	Description
1	Advanced control systems	System to intelligently control remote equipment. E.g. ENWL's C2C project using GE Power-on fusion
2	Communications to and from devices	Communications which support remote devices such as RTTR
3	Design tools	New design tools and software with enhanced capabilities. i.e. the inclusion of EES
4	DSR - Products to remotely control loads at consumer premises	Communications and device to enable DNO-initiated DSR
5	DSR - Products to remotely control EV charging	Devices to enable control of charging of EVs
6	EHV Circuit Monitoring	Monitoring of power flow and voltage on EHV circuits (used for RTTR, for example)
7	HV Circuit Monitoring (along feeder)	Monitoring of power flow and voltage on HV circuits (used for RTTR for example)
8	HV Circuit Monitoring (along feeder) w/ State Estimation	Simplified monitoring of power flow and voltage relying on state estimation
9	HV/LV Tx Monitoring	Monitoring of power flow and voltage at distribution transformers
10	Link boxes fitted with remote control	Communications and control to enable the remote switching of link boxes for temporary meshing solutions
11	LV Circuit Monitoring (along feeder)	Monitoring of power flow and voltage on LV circuits (used for RTTR for example)
12	LV Circuit monitoring (along feeder) w/ state estimation	Simplified monitoring of power flow and voltage relying on state estimation
13	LV feeder monitoring at distribution substation	Measurement devices and appropriate communications to allow the LV loads per circuit at the substation to be monitored
14	LV feeder monitoring at distribution substation w/ state estimation	Simplified version of measurement devices and appropriate communications to allow the LV loads per circuit at the substation to be monitored, based on state estimation
15	RMUs Fitted with Actuators	HV switchgear that is remotely controllable to allow dynamic network reconfiguration
16	Communications to DSR aggregator	Communications links to aggregators for aggregator-led DSR
17	Dynamic Network Protection, 11kV	Network protection to support solutions such as temporary meshing
18	Weather monitoring	Weather monitoring stations with localised communications for use in RTTR
19	Monitoring waveform quality (EHV/HV Tx)	Power quality measurement devices at primary transformers
20	Monitoring waveform quality (HV/LV Tx)	Power quality measurement devices at distribution transformers
21	Monitoring waveform quality (HV feeder)	Power quality measurement devices along an HV circuit
22	Monitoring waveform quality (LV Feeder)	Power quality measurement devices along an LV circuit
23	Smart Metering infrastructure - DCC to DNO 1 way	Communications necessary to allow one-way data flow with the DCC
24	Smart Metering infrastructure - DNO to DCC 2 way A+D	Communications necessary to allow two-way analogue and digital data flow with the DCC
25	Smart Metering infrastructure - DNO to DCC 2 way control	Communications necessary to allow two-way commands and control to be passed between the DNO and the DCC

26	Phase imbalance - LV distribution s/s	Monitoring devices to determine phase imbalance at distribution substations to establish the level of de-rating being caused through imbalance
27	Phase imbalance - LV circuit	Monitoring devices to determine phase imbalance along an LV feeder to establish the level of de-rating being caused through imbalance
28	Phase imbalance - smart meter phase identification	Using smart meters to identify the phase of connection of customers and therefore determine the phase imbalance along a feeder
29	Phase imbalance - LV connect customer, 3 phase	Monitoring device to determine the degree to which a three phase customer's load is balanced
30	Phase imbalance - HV circuit	Monitoring devices to determine phase imbalance along an HV feeder to establish the level of de-rating being caused through imbalance

5.4 Conventional solutions

The smart grid will be built upon a blend of both 'conventional' and 'smart' solutions. Therefore, in parallel with quantifying the smart solutions of the WS3 Phase 1 report, it is necessary to ensure the conventional solutions have been adequately captured. These are outlined in Table 5.4.

Table 5.4 Overview of the conventional solutions and variants included in the model

	Representative Solution	Description	Variants
1	Split Feeder	Transfer half of the load of the existing feeder onto a new feeder	• EHV • HV • LV
2	Replace transformer	New transformer, providing additional capacity and voltage support	• HV (EHV/HV) • LV (HV/LV)
3	New Split Feeder	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	• EHV • HV • LV
4	Minor Works	The construction of one complete new substation electrically adjacent to an area experiencing headroom constraints	• EHV • HV • LV
5	Major Works	The construction of new distribution transformers and circuits into an area where demand cannot be satisfied by simply 'tweaking' existing network infrastructure	• EHV • HV • LV

5.5 Capturing Solution Parameters

The selection of the most appropriate solution for a given network and constraint is a multi-dimensional problem. This is exacerbated as the volume of solutions increase substantially compared to the relatively few options used in conventional network design and operation. It has therefore been necessary to capture a range of parameters for each solution in order to understand:

- when a solution can be deployed
- its cost upon deployment
- its likely impact on the power system

These are described in the following sections.

5.5.1 When to deploy a certain solution – the use of Headroom

The model uses 'Headroom' as the key parameter in determining when investment should take place, and of how much additional capacity is released per solution. This is used as a 'common base', allowing a parallel comparison to be done for:

- **Thermal constraints**
  - ***Thermal Conductor:*** The percentage of thermal constraint on a circuit (overhead line or underground cable) released. A positive figure would represent an increase in the headroom on circuit capacity on the base-case (e.g. a dynamic line rating solution increasing a line rating from 100% to 130% is captured as 30%).
  - ***Thermal Transformer:*** Percentage of thermal constraint of transformer released. A positive figure would represent an increase on the current base-case (e.g. a dynamic transformer rating solution increasing an asset rating from 100% to 120% is captured as 20%). Where: LV = Distribution (HV/LV) Transformer; HV = Primary (EHV/HV) Transformer; EHV = Grid (SGT/EHV) Transformer.
- **Voltage constraints**
  - ***Voltage Headroom:*** Percentage of voltage headroom released. Voltage headroom starting position is based on the difference between the (line) voltage at the transformer infeed and the upper statutory limit.
    - LV – starting position = 1.5% headroom (difference between 433V and the upper statutory limit of 440V)
    - HV, e.g. 11kV – starting position = 6% headroom (as most Primary transformers have tap changers and can optimize voltages in line with Statutory limits)
    - EHV , e.g. 33kV or 132kV - starting position = 10% headroom (as most Grid transformers have tap changers and can optimize voltages in line with Statutory limits)

    An increase in headroom is therefore associated with a reduction in volts on the circuit or at the transformer infeed. A three-phase inline LV voltage regulator with an operating bandwidth of ±20V is captured as giving 5% voltage headroom.
  - ***Voltage Legroom:*** Percentage of voltage legroom released. Voltage legroom starting position is based on the difference between the (line) voltage at the end of a feeder and the lower statutory limit.
    - LV – starting position = 14.5% legroom (difference between the voltage at the busbars (433V) and the lower statutory limit of 376V)
    - HV, e.g. 11kV – starting position = 6% legroom (as most Primary transformers have tap changers and can optimize voltages in line with Statutory limits)
    - EHV , e.g. 33kV or 132kV - starting position = 10% legroom (as most Grid transformers have tap changers and can optimize voltages in line with Statutory limits)

    An increase in legroom is therefore associated with an increase in volts on the circuit or at the transformer infeed. A three-phase inline LV voltage regulator with an operating bandwidth of ±20V is captured as giving 5% voltage legroom.

- **Fault Level constraints:** Percentage of fault level released. As the fault levels differ by voltage level, fault level headroom is applied against the following bases:
    - **LV** – 25MVA: the design fault level for most LV distribution networks in GB
    - **HV** – 250MVA**:** the design fault level for most HV distribution networks in GB
    - **EHV** – 750MVA**:** the lower design fault level for EHV distribution networks in GB, noting that some networks now are designed to accommodate 1000MVA at 33kV.

  A positive figure would represent an increase in fault level headroom on the current base-case – e.g. the use of a Fault Current limiter at 11kV increasing the fault level capacity from 13.1kA (250MVA equivalent) to 16kA is captured as 20%.
- **Power Quality constraints:** Percentage change of power quality. A positive figure would represent an increase in power quality headroom on the current base-case. Initial figures have been approximated, although this functionality is not enacted in the model.

All of the headroom trigger points enacted in the model are assessed simultaneously. When a breach occurs (e.g. load headroom, voltage headroom, voltage legroom or fault level headroom in the default case) in a given year the model seeks to deploy a solution to fix that specific violation by way of an appropriate solution intervention.

In all instances, interventions (via an appropriate Variant Solution) can assist in changing headroom (Figure 5.2). The model considers two ways in which headroom can be released:

1. **Lifting static headroom**: A new asset, or assets, is introduced to physically lift the headroom, for example the insertion of a new electrical circuit or the use of dynamic or real-time thermal ratings, to effectively increase the power capacity of a circuit. This approach is used for load, voltage and fault level headroom constraints (Table 5.3).
2. **Spreading the load shape**: The use of demand-response to flatten the load curve, effectively moving load away from peak time to the shoulders. This approach is triggered by changes in load headroom, once enacted, it can help support voltage headroom, but this is a secondary function (Figure 5.4).

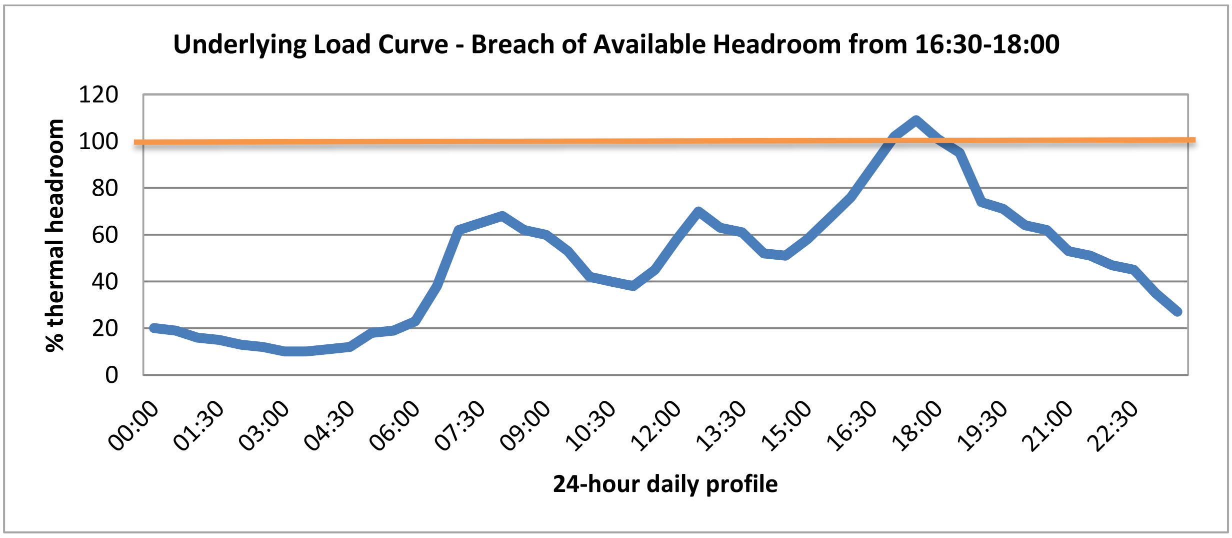


Figure 5.2 **24-hour daily profiles showing a breach of headroom**

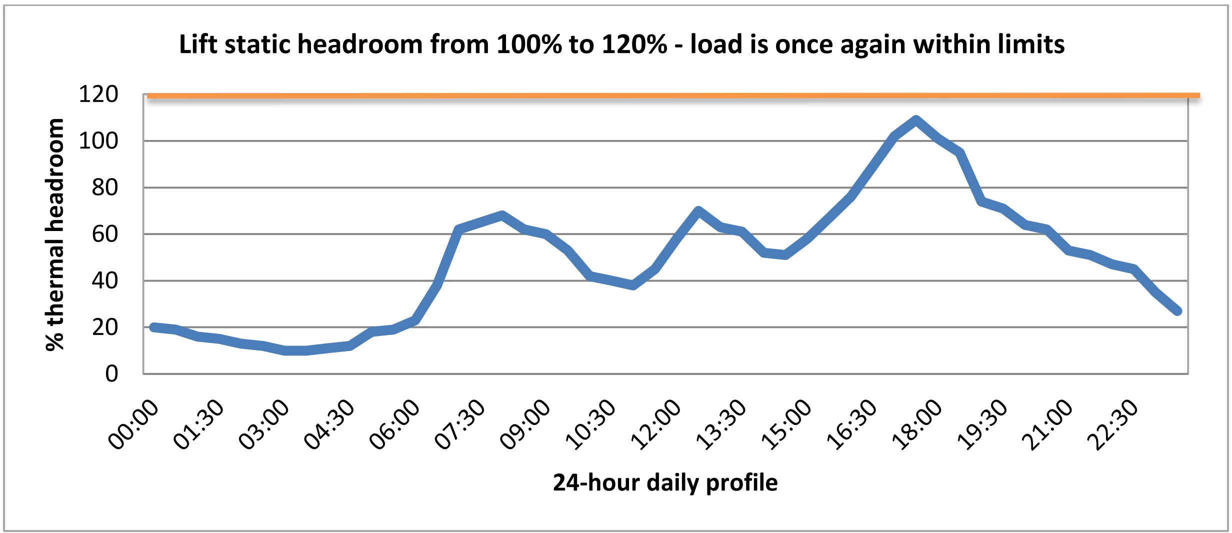


Figure 5.3 24-hour daily profiles showing the effects of lifting headroom

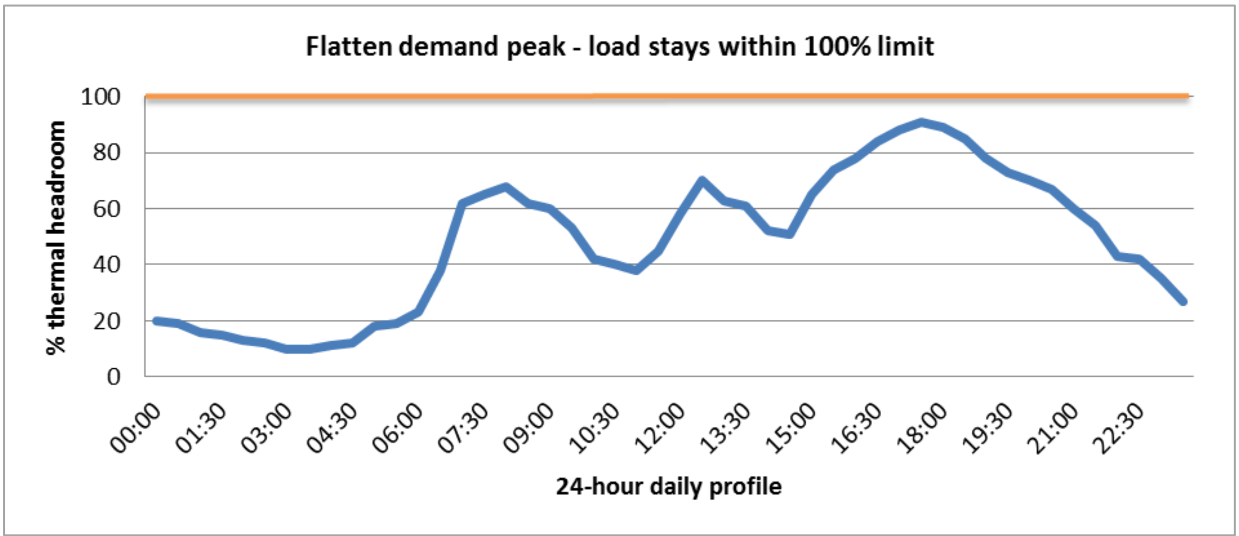


Figure 5.4 24-hour daily profiles showing the effects of flattening headroom

5.5.2 Capturing Solution Costs

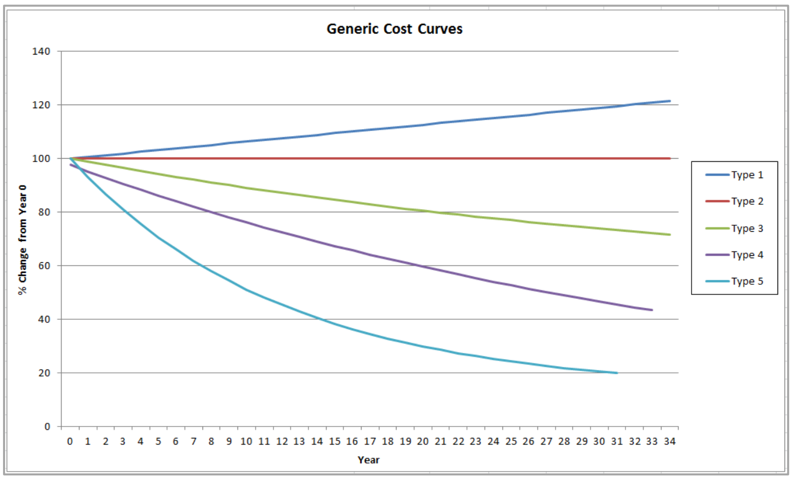
Solution costs fall into two categories:

- **Capital Expenditure:** An estimation of the cost of deploying the solution in a given year (including cost of the technology, land, civil work, connecting equipment, etc.). This cost does not include the costs of associated enablers, which are captured separately, and combined with the solution costs only where necessary.
- **Operational Expenditure**: An estimation of the annual operations and maintenance costs (e.g. communications channels, additional maintenance, etc.) that would be incurred for the on-going use of a solution. This figure is then converted into an NPV equivalent over the life of the solution and using a 3.5% discount rate.

The two costs are combined as total expenditure (Totex) to form the overall cost of deployment.

Cost Curves: Solution costs change over time. To account for this, five cost curves have been included to represent the generic changing costs of a spectrum of different types of technology over time. The technologies that have been chosen offer varied cost curves due to different factors such as volume, material cost price changes and learning curves.

The cost curves are applied to each solution in the model to allow the future costs of solutions to be approximated based on similar technologies. Each solution requires a Cost Curve to be allocated to it. Figure 5.5 shows all of the cost curves plotted together for ease of comparison.



- Type 1 – conventional solutions with a high aluminium, steel or copper content such as transformers, underground cables or overhead lines
- Type 2 – The default position – flat profile
- Type 3 – New solutions, but where volumes are expected to be low (e.g. EHV solutions)
- Type 4 - New solutions, but where volumes are expected to be moderate (e.g. HV or LV network solutions)
- Type 5 - New solutions, but where volumes are expected to be high (e.g. LV domestic solutions, such as EV charging units)

Figure 5.5 Generic cost curve types for use in the WS3 model

The curves are characterized by the equations given in Table 5.5.

Table 5.5 Equations for the five representative cost curves

Type	Equation
1	$0.6312x + 99.369$
2	x
3	$99.576e^{-0.01x}$
4	$99.915e^{-0.025x}$
5	$94.559e^{-0.053x}$

Further details on cost curves are provided in Appendix D.

5.5.3 Inclusion of factors to consider more than direct financial benefits

Several other factors are captured in the solution assessment in addition to solution headroom and cost described above. These provide more subtle measures to inform which solutions should be used and when, via the dynamic Merit Order (more detail in Section 5.6). These are:

- **Disruption factor**: This represents the value attributed to the avoidance of disruption caused to the public by the installation and operation of a solution.
- **Flexibility factor**: This represents the ability to re-deploy a solution during the life of the asset.
- **Cross network benefits factor**: This recognises that some solutions give positive benefits to higher or lower voltage levels (e.g. the use of DSR at LV, has the potential to change the demand profiles seen at HV and EHV, potentially reducing upstream headroom breaches).

Details of these factors, together with the weightings assigned in the model are provided for reference in Appendix D.

5.5.4 Capturing other incidentals affecting the power system

The transition to smart grids has the potential to affect different performance aspects of the power system. Electrical losses for example, will increase with the deployment of some solutions, such as electrical energy storage (as the conversion in and out of the battery is not lossless) or real time thermal rating (where resistive loss will increase with increased circuit loadings). These factors are captured on a per Variant Solution basis, considering the potential change for a given network voltage level:

- **Impact on Fixed Losses:** The estimated impact on fixed losses such as transformer iron loss, storage unit running losses. A positive figure would suggest an increase in losses; a negative figure would be a reduction in losses.
- **Impact on Variable Losses**: The estimated percentage impact on copper losses (e.g. I^2R losses) on a given circuit or asset. A negative figure would indicate an improvement (reduction) in losses; a positive figure would indicate an increase in losses. Some 'smart solutions' can have a detrimental impact on technical losses, for example the use of dynamic line rating (where the line rating is increased from 100% to 130%), could increase losses by as much as 69% (due to the squared relationship between current and line losses) if running at full rating continuously.
- **Impact on quality of supply**: Estimated percentage impact on a feeder CI/CMLs. A positive figure would indicate an improvement in Supply Quality, a negative figure would indicate a reduction in Supply Quality (on the base case).

5.5.5 Populating a common template

The supporting Annex on 'Detailed Solution Data' captures the parameters and assumptions used for each of the Variant Solutions (Conventional and Smart) and of the Enablers. It is noted that this is the first time, as far as the authors are aware, that this approach has been taken across such a wide range of solutions. The data shown in these templates has been entered into the model and forms the basis of the results shown in this report. As the model is fully parameter based, any of the assumptions can be changed, which will have an impact on the results.

As many of the solutions are new to the market, much of the assessment contained in this Annex is based on engineering judgement, rather than robust, repeatable evidence. It is therefore expected that the parameters contained within these sheets will be refined over time, improving the outputs of the model. This is particularly true as LCN Fund projects continue to progress and deliver results on individual solutions. Any solutions identified as currently undergoing trials via an LCN Fund project, have been highlighted in the template.

5.6 Selecting Solutions using a Variable 'Merit Order'

In the Evaluation Framework developed under Work Stream 2 of the Smart Grids Forum, solutions are 'selected' from a pre-defined merit order stack that is set manually. The increased number of solutions and variety of networks of the WS3 model makes it both cumbersome and unwieldy to continue with the manual process.

The generation of the merit order has therefore been automated with the development of a variable 'merit order stack'. This prioritises the way in which solutions, both smart and conventional, are applied to networks to solve headroom/legroom issues. Each solution is quantified in a tangible way in order to create a single comparative value. The merit of each solution is characterised by a 'cost function' of the following components:

- **Totex** – the sum of capital expenditure plus the NPV of annual operating expenditure over the life of the asset (described further in Table 13.10 of Appendix D)
- **Disruption** – the value placed on avoiding the disruption required to install and operate a solution. This is converted from a 1-5 scale into a £ value (described in Table 13.11 of Appendix D)
- **Cross Network Benefits** – the ability for a solution to deliver benefits to an adjacent network (e.g. a HV solution that also gives a benefit to LV network or EHV network). This is converted from a 1-5 scale into a £ value (described in Table 13.12 of Appendix D)
- **Flexibility** – the ability to relocate/reuse a solution when it has fulfilled its primary purpose. This takes into account the asset life expectancy and any ancillary benefits offered by the solution. This is converted from a 1-5 scale into multiplication factor (currently set from 0.8x for high flexibility solutions to 1.0x for low flexibility solutions – again, this is shown in Table 13.13 of Appendix D)
- **Life expectancy** – this considers the residual life of the asset at point n in time (where n is set to be the number of years forward in time for the model to resolve a problem, following a breach of headroom)

The components are combined such that:

$$\boldsymbol{Merit\ Order} = \boldsymbol{Flexibility}.\left(\frac{\boldsymbol{Life\ expectancy} - \boldsymbol{n}}{\boldsymbol{Life\ expectancy}}\right).[\boldsymbol{Totex}\ £ + \boldsymbol{Disruption}\ £ + \boldsymbol{Cross\ Networks}\ £]$$

Each solution therefore has its own Merit Order ‘cost function’. This is different from the cost of the solution (the totex), and is only used for the purposes of ranking solutions against each other.

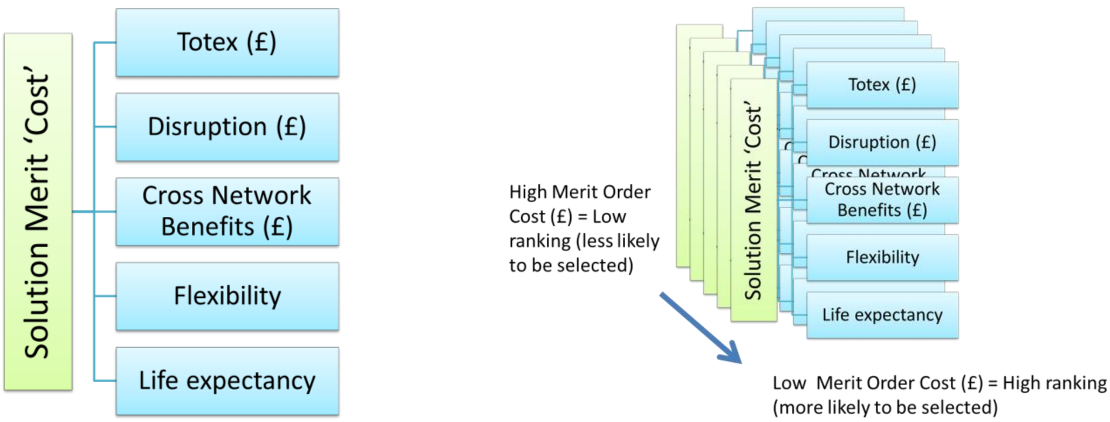


Figure 5.6 Overview of the Solution merit order ‘cost function’

The merit order stack is arranged such that the cheapest solutions, high merit, are at the top of the stack and the most expensive, low merit, are at the bottom of the stack. Each solution is flagged with the applicable network types for that solution.

Unranked solutions

Solution (inc variant)	
Dynamic Network Reconfiguration - HV	New
D-FACTS - HV	New
DSR - DNO to commercial customers	New
Permanent meshing - HV	New
Temporary meshing - HV	New
HV split feeder	Conventional
HV new split feeder	Conventional
Large 33/11kV transformer	Conventional

With cost function applied

Solution (inc variant)	
DSR - DNO to commercial customers	New
Dynamic Network Reconfiguration - HV	New
Temporary meshing - HV	New
Large 33/11kV transformer	Conventional
Permanent meshing - HV	New
D-FACTS - HV	New
HV split feeder	Conventional
HV new split feeder	Conventional

Figure 5.7. Example of some of the HV solutions, and how the merit order cost function has changed the ranking of solutions (for illustration only)

Figure 5.6 shows how the model uses the merit order stack. The model uses the stack firstly to select the cheapest single solution, as defined by its merit order cost, which can be applied to solve a headroom/legroom issue. Once the single cheapest solution has been found (if it has been possible to solve with a single solution), the model will proceed to find the cheapest combination of two solutions which solves the given issue. This will repeat for combination of up to three solutions in a given year. This approach is consistently applied for both smart and conventional solutions.

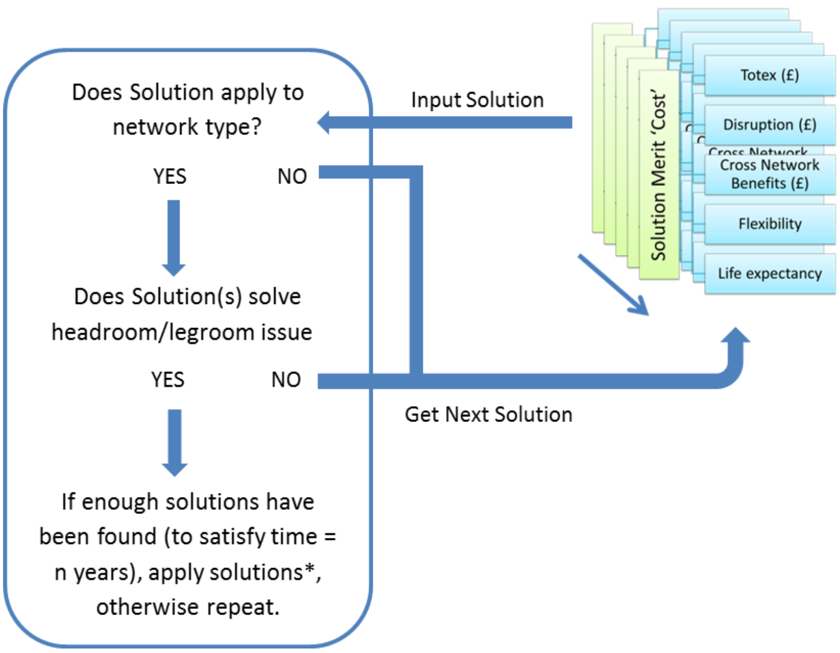


Figure 5.8 Flow chart showing how solutions are applied in the WS3 model from the Merit Order Stack

The model credits solutions that are deployed to solve one headroom constraint that have an impact on other headroom parameters (e.g. a solution that is deployed to resolve a voltage legroom violation may also increase load headroom).

It is noted that the merit order does not factor in any regulatory mechanisms (such as the equalised incentive, losses incentive, etc) that might bias decisions towards certain types of solution.

5.7 Considering other interactions

The WS3 model contains several features to compensate for different requirements and interactions between a large range of solutions.

5.7.1 Meeting future headroom requirements

The WS3 model includes an ability to ensure that headroom mitigation occurs for a number of years (n) ahead in time – i.e. avoiding multiple consecutive years of investment. The results contained within this report considers n = 5 years as a base case. Sensitivity runs have been included in the Results chapter (Section 8).

Furthermore, the model can be adjusted to offer x% of headroom after n years; i.e. the model can be set to calculate the optimal investment to give exactly enough headroom to last for 5 years, or could be set such that in 5 years' time there is, say, 10% of headroom still available. As a default, it is set to ensure 1% of headroom after 5 years.

5.7.2 Solution Life expectancy

Many of the smart solutions have a shorter life expectancy to the typical 40-50 year asset lives seen for conventional solutions. It is necessary to capture these in order to fully capture the costs of a solution (i.e. a solution deployed in 2020 with a life-expectancy of 15 years would have to be replaced in 2035 – within the timescales of the model).

When a solution expires, it is replaced (year p – where p is the life expectancy of the solution), either by the same solution again (if no new headroom is required), or by a different solution if the headroom in year p (plus n) will not be met by the original solution.

The 'residual value' of the solution is a measure in the merit order that considers the useful life left in a solution. For DSR (as an example) the residual value of a five year contract is assumed to be £0 at the end of its life, whereas a transformer (or storage unit, D-FACTs unit, etc.), will have a number of 'useful years' left (it will not have depreciated to £0 after five years).

5.7.3 Relationship assessment

By looking at the relationships between the three headroom parameters (load, voltage and fault level) in parallel, we can account for combinational effects such as:

- Low carbon technology deployment – e.g. a PV cluster may support EV charge-at-work load, where the effects are coincidental; and
- Where the deployment of a solution to manage a voltage problem would also assist in solving a thermal constraint (albeit to a potentially lesser degree)

5.7.4 Which solutions where

Certain solutions are only applicable at certain voltages, and / or to particular network types. For example, some solutions cannot be applied together, e.g. permanent meshing and temporary meshing, or meshing and remote controllable open points. In order to accommodate this, all of the solutions are listed in a matrix, showing which solutions can be applied with one another, and which are exclusive.

5.7.5 Demand Side Response (DSR)

Residential DSR (and most electrical energy storage solutions[25]) are treated differently in the model. The model considers which loads can contribute to Residential DSR. This is done on a granular bottom-up basis, by considering the loads of domestic properties and commercial premises that can be altered, and when, across the 24 hour period, they could be moved. It then considers what proportion of this load is amenable to Residential DSR.

It should be noted that, within the model, demand can only be shifted ‘intra-day’, i.e. it is possible to shift demand from one portion of the day to another portion of the same day. It is not possible to shift demand to a different day.

There are four main cost considerations captured for Residential DSR solutions:

- Initial capex: The costs to enable the solution on a per feeder basis
- On-going opex: The annual costs for communications channels
- Inconvenience cost: The costs of how much the DNO may have to pay the customer[26]
- Cost to GB bulk generation of potentially having to generate at non-optimal time

Further detail on how the ‘DNO-led DSR’ interfaces with ‘nationally-driven DSR’ can be found in Section 6.1.2.

The model considers the costs and benefits of making use of DSR, taking into account the fact that various types of DSR will have different costs associated with them (e.g. the cost of employing an aggregator as against directly engaging with customers).

For HV and EHV connected customers, DSR is applied in a more simplistic manner. In this instance, a fixed amount of load is removed at the relevant time of day, therefore avoiding headroom breaches. Unlike the LV customer DSR, this load is not added back into the model, but is treated as demand reduction. This approach is relevant to the following solution variants:

- DNO to Central Business District DSR
- DNO to aggregator led commercial DSR (HV customer)
- DNO to aggregator led commercial DSR (EHV customer)
- DNO to commercial DSR (direct with HV customers)
- DNO to commercial DSR (direct with EHV customers)

[25] EES - HV Central Business District (commercial building level) is treated more simplistically in the model as providing a static increase in headroom.

[26] This represents a real resource cost and is not just a transfer, since customers may face actual costs when shifting their demand.

6 Modelling the wider electricity sector

In this section, we look at the way in which the model deals with the wider electricity sector. This incorporates the cost of generation and transmission across GB and how nationally-led DSR may be utilised to reduce these costs.[27] The interface between this DSR and the interventions that may subsequently be applied by network operators at a local level is also discussed. We also describe the discount rate applied by default in the GB-wide model for NPV calculation of investment.

6.1 Modelling at a national level

Although the majority of costs and benefits incorporated within the model accrue to the distribution networks, the actions of generators and suppliers are still important. This is for two reasons.

- First, consistent with the model developed for WS2, it is assumed that DSR may be carried out at a national level to reduce costs of generation. This is significant for DNOs since:
  - any such DSR will change the profiles of load that networks face; and
  - DSR carried out at the national level may limit the scope for any additional DSR carried out at the local level by DNOs.
- Second, the GB-wide social CBA considers the costs of generation, which may vary if action by DNOs (notably the use of DSR or storage) affects load at the national level.

The model therefore simulates DSR carried out at the national level and estimates the national costs of generation. The following sections describe these components of the model.[28]

6.1.1 Integration of generation and national 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

[27] While nationally-led DSR could also be used to reduce the costs of reinforcing the transmission network, in order to maintain tractability the model does not explicitly deploy DSR for this purpose. However, the model does provide a basic estimate of possible savings in transmission reinforcement due to national DSR, described further on in this section.

[28] The areas of the model described here function identically to the generation modules of the WS2 model. Further information on that model can be found in Frontier Economics and EA Technology, *A framework for the evaluation of smart grids*, 2011 (http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=44&refer=Networks/SGF/Publications).

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.

Further details on the modelling of DSR are presented in the Annex.

Figure 6.1 illustrates how the model functions when performing a GB-wide CBA. The initial load profiles (before any DSR is applied) are first modified to take into account the effect of any DSR carried out to reduce national generation costs. These profiles are inputted into the simulation of the distribution network, which determines the costs of any required reinforcement. Finally, the resulting load profiles (after any additional DSR carried out at the local level) are passed through a simple simulation of GB-wide generation, in order to estimate the costs of generation.

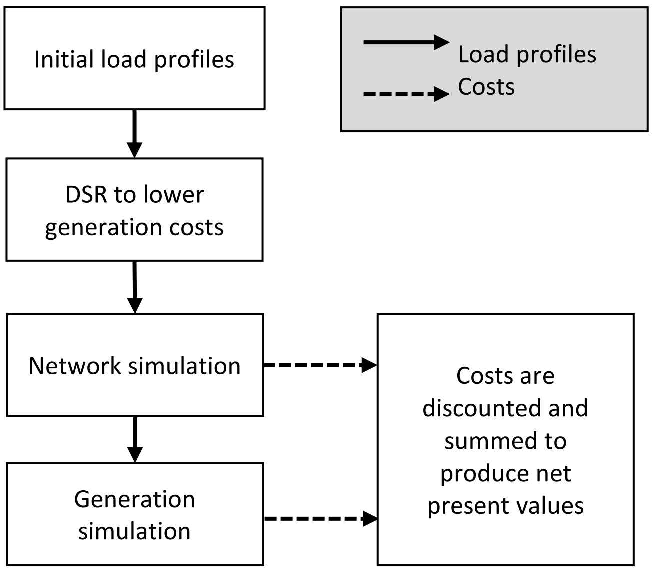


Figure 6.1 Model flow for GB-wide social CBA (Source: Frontier Economics)

When the GB-wide model is run to look at only those costs accruing to DNOs, there is no need to calculate the costs of generation. The model therefore misses this stage, as illustrated in Figure 6.2:

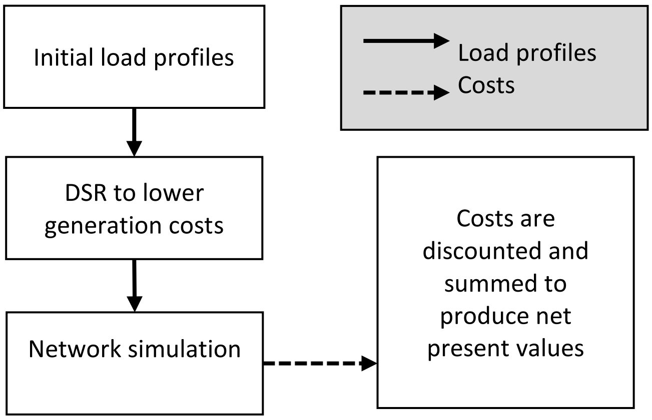


Figure 6.2 Model flow for GB-wide DNO CBA (Source: Frontier Economics)

The licence area specific model does not need to determine generation costs, since it only considers those costs accruing to a DNO. However, it is still necessary in this model to take account of the effects of any DSR carried out by suppliers at the national level. This is not carried out within the licence area model itself, since this will contain region-specific penetrations of load types (such as electric vehicles), rather than the GB-wide penetrations required to model national-level DSR. Instead, users are able to copy over the load profiles generated by the GB-wide model into the licence area model.

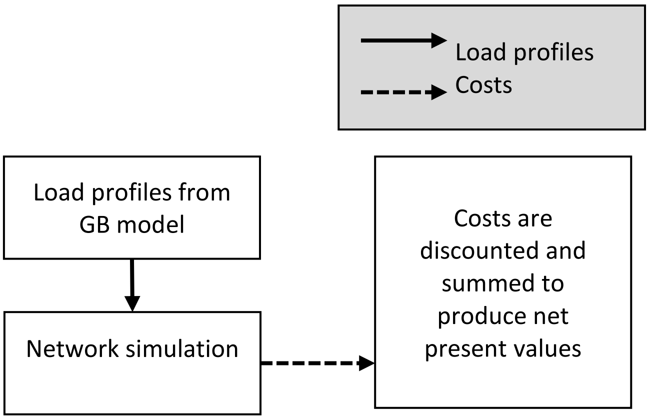


Figure 6.3 Model flow for licence area DNO CBA (Source: Frontier Economics)

6.1.2 Nationally-driven DSR to reduce costs of generation

Smart meters are being rolled out to all domestic users by 2019, irrespective of whether any additional investment in smart grids takes place.[29] As described in Section 1.3.1 – differentiation between 'smart grid' and 'smart meter', smart meters are a component of the wider smart grid and may, by themselves, facilitate DSR by suppliers aimed at lowering the national costs of generation.

The 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. The analysis therefore seeks

[29] 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.

to identify and measure the additional functionality that smart grids would provide, over and above the functionality provided by the planned smart meter rollout. As such, it is assumed that national-level DSR can occur regardless of the network investment strategy (BAU, top-down or incremental) adopted. This national level DSR entails a response to system-wide generation costs, for example a real time response to changing levels of wind output.

To simulate such DSR, the model considers the load shifting that may be possible for each type of load (such as electric vehicles, or heat pumps). Each type of load is associated with a set of parameters that describe how amenable it is to DSR:

- what proportion of load may be moved
- which half-hour periods in the day load may be moved between
- the extent of any energy loss associated with the action (i.e. if for any kW shifted away from one period, more than 1 kW will need to be added in another period)[30]
- the level of customer costs associated with carrying out DSR (such as the inconvenience of shifting load)

For many of the load types within the model (such as the baseline residential load) it is assumed that no DSR is possible.

The model considers each load type in turn, starting from the least flexible. For each representative day, it moves load from periods of high national demand to period of low national demand. As it does so, it calculates generation costs (described below). Load is only shifted if the associated reduction in generation costs exceeds the customer costs associated with DSR.

Locally-driven DSR is additionally modelled as a smart solution applied to individual feeders, which can further shift load to reduce the need for local network reinforcement. The model ensures that any such additional DSR is consistent with the DSR carried out at the national level in the following ways:

1. The starting point for any DSR carried out at the local level is the profile of load that results from national-level DSR.
2. The same parameters that constrain load shifting at the national level are used when considering localised DSR. This ensures that if, for example, the maximum possible heat pump load has already been moved to reduce the costs of generation, it is not possible to move additional heat pump load to reduce the need for local reinforcement.
3. The model calculates the average reduction in generation costs from each kW of load shifted at the national level. The algorithm that determines whether to shift load further at the local level balances this average cost of reversing any national DSR against the gains at the local level. This reduces the possibility that the gains from locally-driven DSR could be outweighed by resulting increases in the costs of supply[31].

[30] This parameter can also be used to simulate load shedding, where there is a net reduction in load over the day.
[31] The model does not seek to fully optimise the deployment of DSR for different purposes to minimise social costs, since this would add considerable extra complexity without significantly impacting the results (which are almost entirely driven by non-DSR smart solutions).

6.1.3 Generation and transmission costs

For the GB-wide social CBA, the model estimates the total cost of generating sufficient electricity to meet demand. To do this, the model incorporates data on the capacity[32] and costs (opex, carbon emission costs, and capex)[33] of a representative collection of generation technologies. The model calculates the costs of dispatching sufficient generation to meet demand net of embedded generation.

Representative half-hourly profiles of varying wind output are used to take the intermittency of wind generation into account.[34] Wind generation is subtracted from total demand before generation costs are calculated.

Consistent with WS2, the model also produces a simple estimate of transmission network reinforcement costs. This is based upon historic levels of transmission network investment associated with growth in GB-wide demand: the model does not consider inter-regional power flows.

6.2 Discounting

Discounting is applied in the WS3 model so that costs and benefits that occur in different time periods can be compared. Application of a discount rate is required to take into account the general preference to receive goods and services sooner rather than later.

6.2.1 Social discount rate

The social discount rate is applied to reflect the 'social time preference': society's preference to receive things now rather than later.

The WS3 model allows a social cost benefit analysis to be undertaken at the GB level. The social cost benefit analysis assesses the costs and benefits of options from the perspective of society as a whole, rather than from the perspective of any particular individual or organisation within society. When using the model to undertake a social cost benefit analysis, a social discount rate should be used.

The social discount rate used in the model is 3.5% (in real terms), in compliance with Green Book guidance[35]. This is also consistent with the discount rate used in the SGF WS2 model. All of the costs

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[32] Generation capacity is based upon National Grid's *Gone Green* scenario for all scenarios apart from low decarbonisation, which is based upon National Grid's *Slow Progression* scenario. The total capacity of generation is scaled to meet modelled demand, holding the mix of generation types constant.

[33] As in the WS2 model, costs have been taken from PB, for DECC (2011), Electricity Generation Cost Model – 2011 Update Revision 1 (http://www.decc.gov.uk/assets/decc/11/about-us/economics-social-research/2127-electricity-generation-cost-model-2011.pdf) and Arup, for DECC (2011), Review of the generation costs and deployment potential of renewable electricity technologies in the UK (http://www.decc.gov.uk/assets/decc/11/consultation/ro-banding/3237-cons-ro-banding-arup-report.pdf). Carbon and fossil fuel price projections were taken from the Inter-departmental Analysts' Group policy appraisal guidance (http://www.decc.gov.uk/media/viewfile.ashx?filetype=4&filepath=Statistics/analysis_group/81-iag-toolkit-tables-1-29.xls&minwidth=true).

[34] These profiles are based upon historic wind generation data from Elexon.

[35] HM Treasury (2003) Green Book, http://www.hm-treasury.gov.uk/d/green_book_complete.pdf. For periods between 31 and 75 years into the future, the Green Book recommends a lower discount rate of 3.0% is used. The model does not consider this, since it would increase its complexity without significantly affecting the results.

estimated by the model (including both the costs of network investment and generation) are discounted at this rate to produce the results of the social CBA.

The social discount rate is also used when capitalising the opex associated with investments on the distribution networks. In order to maintain the tractability of the model, the value of 3.5% has been hard-coded in to the opex values for this capitalisation. This will lead to a slight inconsistency if a different discount rate is chosen by users for the main CBA. For example, if a higher discount rate is subsequently chosen for the social CBA, opex will be marginally overstated (since the 3.5% discount rate will still be used for the capitalisation). The social discount rate is also used to capitalise opex in the cost function used to generate the merit order in the priority solution stack. This is because the merit order in the priority solution stack is based on the assumption that DNOs should choose the investments that are optimal from society's point of view.

6.2.2 Rationale for annualising capital costs

Capital costs are annualised in the WS3 model when comparing overall strategies in the social CBA. Annualising converts one-off capital costs into annual equivalent payments, taking account of the discount rate.

Capital costs are annualised to ensure that the fact that the analysis is cut off at 2050 does not skew the results. Without annualising, if an investment with a lifetime of 40 years occurs in 2049 in the model, its full costs will be counted in the cost-benefit analysis, but only one year of the benefits associated with the investment will be counted. Annualising ensures that only one year's worth of costs is compared with one year's worth of benefits.

It is important to annualise costs and benefits if the overall costs and benefits of strategies are to be compared on a like-for-like basis. However, it may be useful to look at costs without annualisation, for example:

- to understand the likely profile of capital expenditure that is associated with each strategy, annual costs without annualisation or discounting should be viewed; and
- to understand the net present value of costs that will be incurred before 2050, the discounted net present value of unannualised costs should be viewed.

However to decide on the strategy with the highest net benefit from society's point of view, annualised costs should be used.

7 A systems approach to innovation deployment on networks

In this section we discuss how the model can be used to assist in the development of a systems approach to smart grid deployment through the identification of solution 'tipping points'. In doing so, it may be possible to drive further synergies across the value chain.

To provide a context for innovation on power networks, the diagram below illustrates in a generalised style, representative innovation stages for network companies. This would apply around the world and there is evidence to suggest that British companies are further advanced than many of their peers[36].

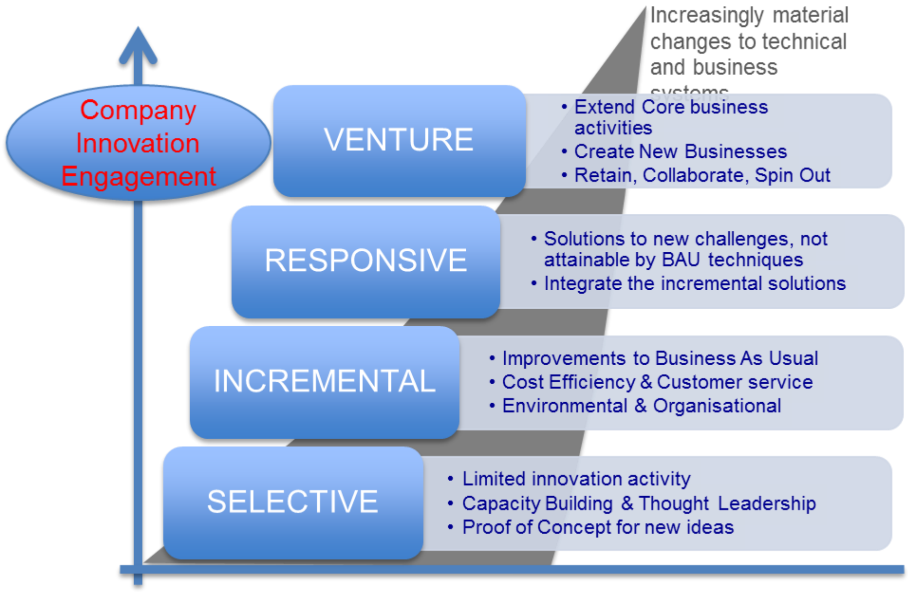

Figure 7.1 Choices of company innovation engagement (Source: WS3 Phase 1 Report)

The representation of network company engagement in Figure 7.1 shows the drivers for each stage, the increasing technical and business complexity that arises, and the potential for new commercial opportunities that become available, if companies choose to pursue them.

Using the descriptions on the diagram, GB network companies have in recent years progressed from 'Selective' to 'Incremental' and are in some cases now moving into 'Responsive'. An interesting feature of these developments is that, while they benefit from regulatory innovation incentives, they are not simply 'grant funded' and have the commercial engagement of companies, within the liberalised market framework of GB.

Any solution starts as a cost until benefits start to be derived; there is then a trend towards decline, at which point (or in the run up to this point), a new product or solution, ideally, needs to be developed and commercialised. The ability to predict this decline and thus the need for innovation, offers a smooth transition to survival. In essence, this is known as the 'step change dilemma'.

[36] www.ofgem.gov.uk/Networks/Techn/NetwrkSupp/Innovat/ifi/Pages/ifi.aaspx
www.ofgem.gov.uk/networks/elecdist/lcnf/pages/lcnf.aspx

7.1 The Step Change Dilemma

All technologies, solutions, developments, even businesses, experience the features shown in the figure below. A cost is incurred in the early years with the solution acting as a drain on the business, until it starts to generate a return, until it reaches sometime in the future where it begins to decline. The key to avoiding catastrophic decline is to invest in successor solutions, before the initial peak wains. This is a challenge, as it can be incredibly difficult when riding the initial wave to accurately predict the top of the curve.

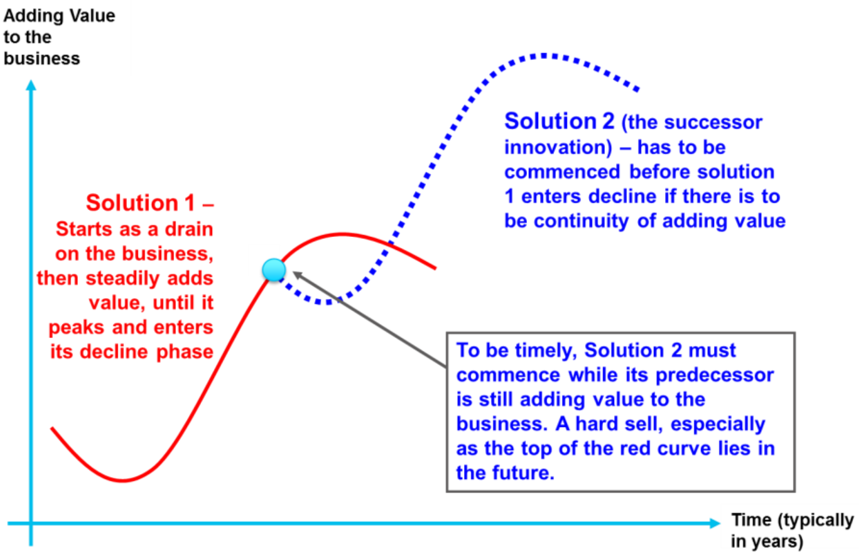

Figure 7.2 Overview of the step change dilemma

There are many examples of step changes both within and outwith the electricity sector, including: Power networks moving from DC to AC; Interconnection of LV networks; A-Roads overlaid by Motorways; Natural gas replacing town gas; Railway electrification; Digital TV switchover.

The characteristics of step change can include:

- The New is a fundamental shift in design philosophy
- The benefits may not be 'guaranteed' or evidenced immediately
- New may have to replace old, or may work in tandem with it
- There are new skills, technologies, uncertainties and risks
- The New changes 'the way things are done'
- It creates new headroom - and opportunities for further change

7.2 Step changes as a result of innovation

It became clear under Work Stream 3 Phase 1, that two broad areas of innovative network solutions could be identified. Firstly, those developments that are generally achievable now with the necessary development and integration, and secondly, those that require further research and more fundamental, focused action. The diagram below illustrates this, and the step changes needed to achieve innovation.

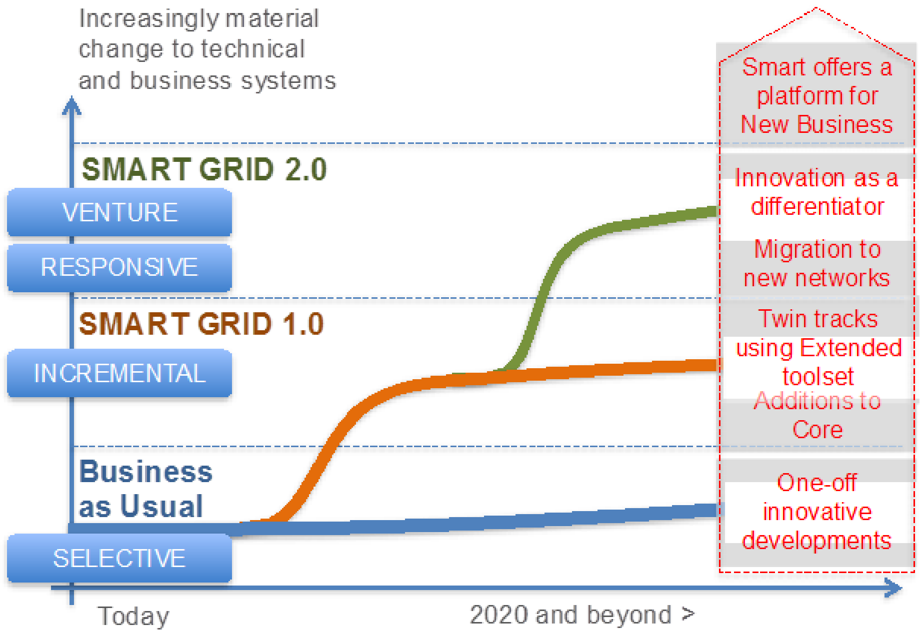

Figure 7.3 Step changes to innovation (Source: WS3 Phase 1 Report)

The WS3 Phase 1 report identified a twin development approach to innovation, illustrated in Figure 7.3; ‘elemental’ development creates the building blocks necessary for planning and delivery, and ‘strategic’ development brings together the component parts into a coherent whole. Integration of these delivers the full benefits and sends clear signals to markets and stakeholders. From this, it is suggested that a strategic / systems approach is needed at company, system operator and national levels.

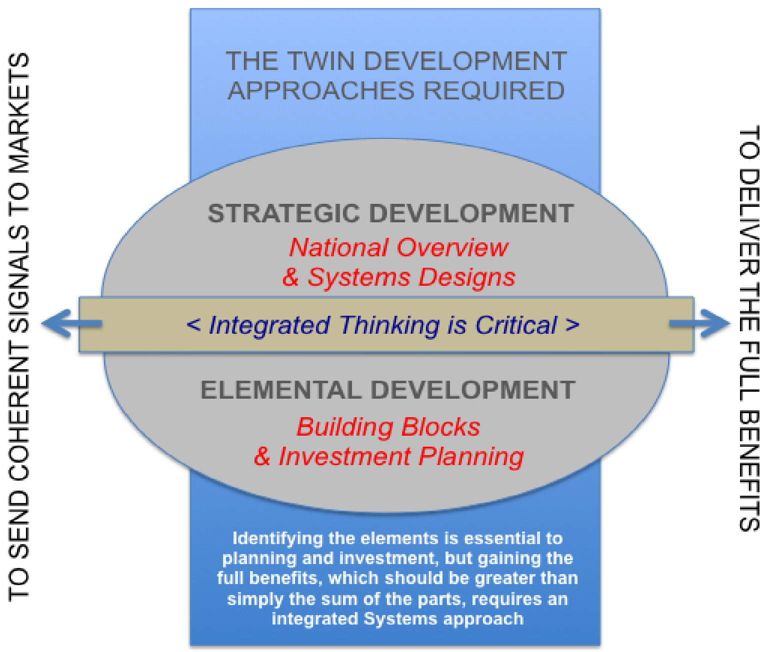

Figure 7.4 The twin development approach to innovation (Source: WS3 Phase 1 Report)

7.2.1 Incremental project delivery

Large single projects, such as the construction of a new power station, high-speed rail link, etc usually adopt a systems approach from the start. However, incremental projects may not. Examples of incremental networks projects are: asset condition monitoring, overhead line real time ratings, power electronics FACTS devices, distributed storage. The risk with incremental solutions is that, they can be treated as many mini deployments in isolation; potentially falling short of delivering the macro benefits that a more holistic approach might have provided.

The management of incremental projects therefore requires special attention. An integrating framework, a systems approach, should be part of the project thinking from the start. Following successful proof of concept it is important to formalise this, as overlooking it is likely to have an adverse and cumulative business impact. It is vital to know when this threshold may be reached. Key questions to be answered are around the expected deployment tipping point for each technology (see Section 7.2), and the point at which a Framework will add value and off-set cumulative technical and business risks, whilst also addressing supply chain and stakeholder issues.

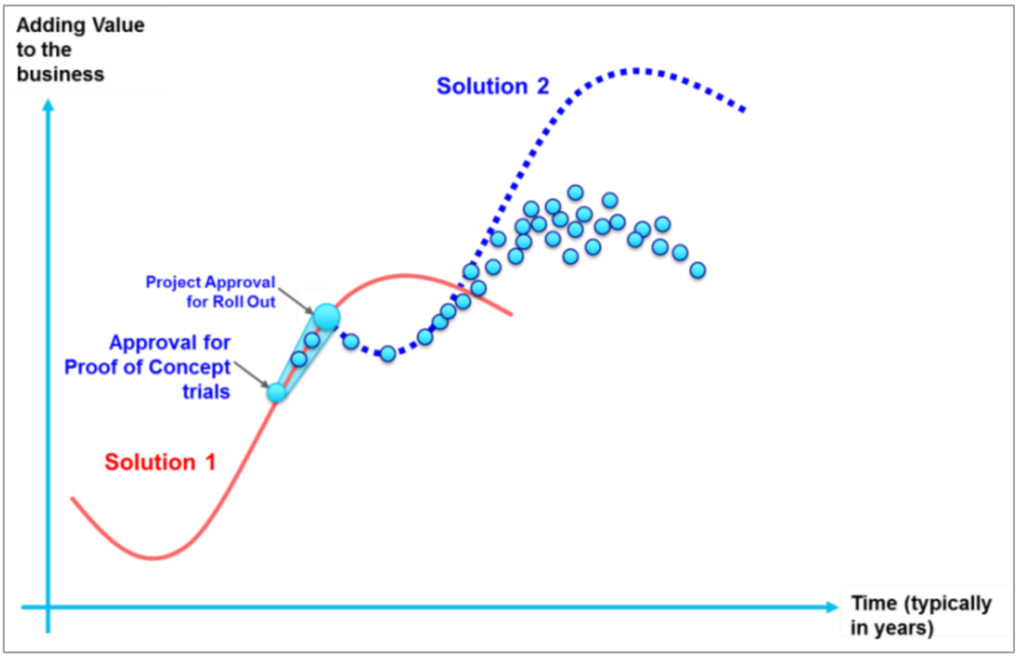

Figure 7.5 Incremental project delivery (Source: Chiltern Power)

7.2.2 An integrating framework

Use of an integrated framework for incremental project delivery ensures a whole system perspective, being of an open and standardised, i.e. functional design. The fully integrated plan will allow for new equipment working with old, have expansion capability, and be data compatible with asset, operational and business systems. The overarching benefit of an integrated framework is that it enables innovative solutions to become 'part of the planner's toolkit', in effect, the new business as usual.

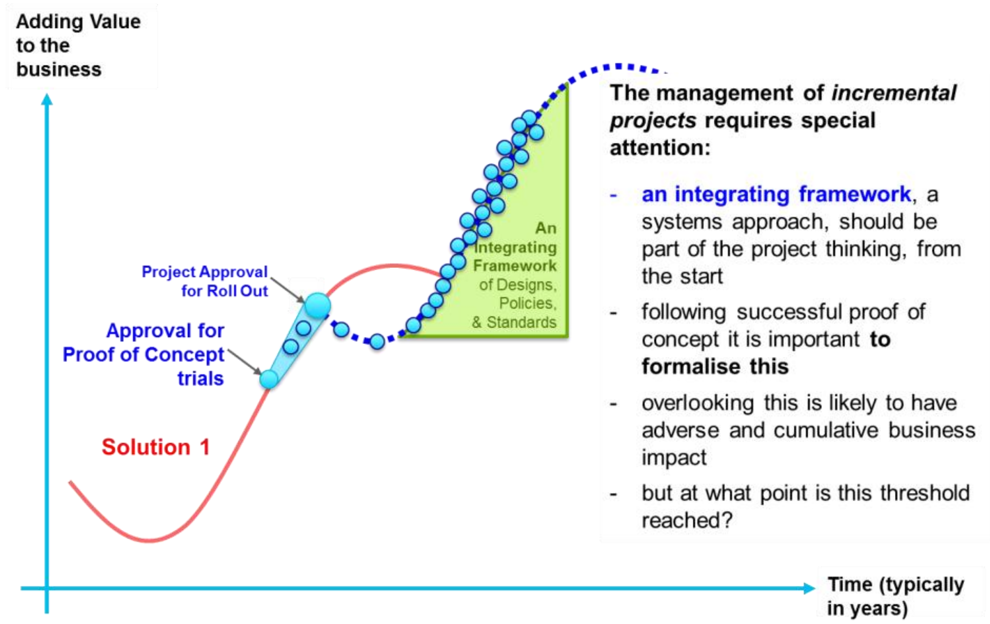

Figure 7.6 The use of an integrating framework to factor in a systems approach (Source: Chiltern Power)

Benefits of an integrated framework may be categorised under benefits for business, the customer, and in terms of operation.

The framework offers benefits to business as it is simpler and faster to deploy, enables multi-vendor procurement and data access for the business. Cost efficiencies may be realised in that spare holdings can be standardised, and training requirements are common throughout. The framework can act as a catalyst for regulatory changes, and exist as a platform for new opportunities.

Customer benefits may be realised through faster access to new services, lower overall costs, and the customer will be at less risk of rework and upgrades. Quality of supply impacts are re-risked, whilst there is a consistent third party interface.

Local, regional and national integration offers operational benefits, leading to a stable and predictable operational performance.

7.3 Identification of tipping points

A systems approach is needed for a particular technology type when either scale hits its 'trigger' or 'tipping' point limit; this is a function of the 'impact' for that technology and the number of applications of it within a DNO licence area. This is illustrated in Figure 7.5.

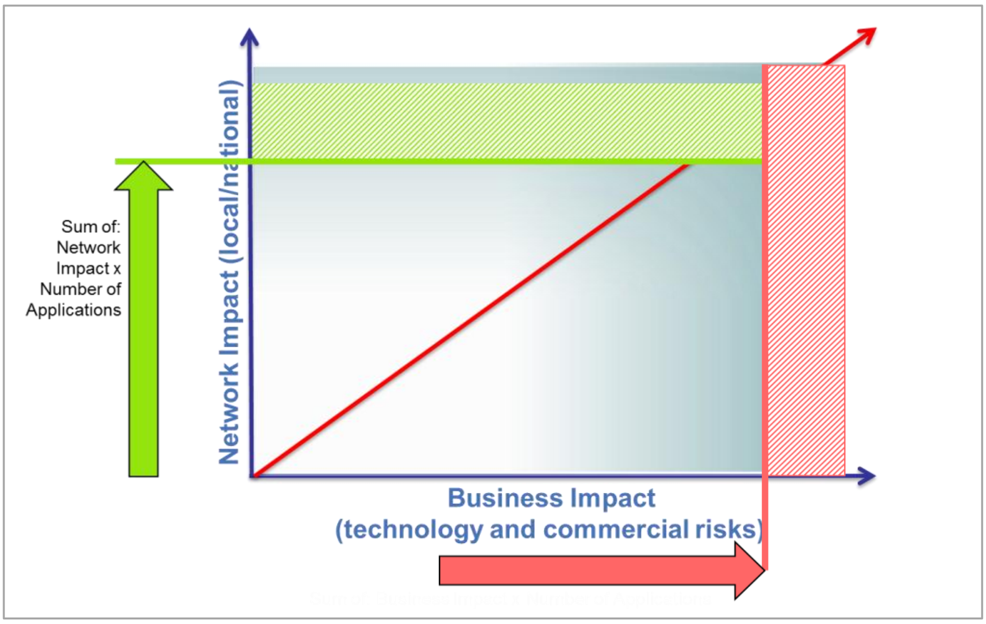

Figure 7.7 Identification of impact and trigger points (Source: Chiltern Power)

Capturing step change and integrating frameworks are important in the context of smart grid solutions for GB. The WS3 model can be used to identify tipping points, which occur when, for a particular solution, there are sufficient numbers of the devices in service for a pre-set threshold to be crossed.

Two thresholds have been identified:

1. Concern for the number of devices, likely to have network impact on local or national security of supply or dynamic stability; or
2. Concern for the total financial materiality of the installed solutions, considering write-off risks, or the case for stronger procurement and operating cost optimisation.

The model will indicate when 'tipping points' are reached; this looks at when volume becomes sufficiently high that some form of standardisation becomes necessary.

Table 7.1 Illustration of tipping points reached for four smart solutions

	Tipping Point	Year Reached
Active Network Management - Dynamic Network Reconfiguration_LV	50000	2026
Enhanced Automatic voltage Control (EAVC)_LV PoC voltage regulators	50000	2037
Permanent Meshing of Networks_Meshing LV Urban Networks	50000	2040
RTTR_RTTR for LV UG cables: coupled with demand forecast: particularly for long time constant assets	50000	2028

When one of the above thresholds is exceeded the model produces a 'flag' in that year. This can be used to inform a network company's business strategy and/or alert other stakeholders. To disassemble the problem, it is helpful to consider the extent of Network Impact and the extent of Business Risk for each type of network innovative solution. The WS3 model can be run for the whole GB system, or by a network company for its own system.

At the tipping point a steeper ‘cost learning curve’ could be applied in the model. The model would flag when the application of any particular smart solution (e.g. 11kV fault Limiters, or 33kV FACTS devices) reaches a tipping point.

7.4 Key points of the integrated framework approach

Incremental innovation projects require special attention; to gain the full benefits of these investments, an integrating framework is needed. The ‘tipping point’ indicates when this framework should be in place, and the WS3 Phase 2 model flags likely tipping points for further attention. Whilst this is novel work, the results are highly informative, and innovation strategies for network company RIIO business plans will benefit from this analysis, albeit there may be implications for wider stakeholders. Further work is needed to develop the understanding of the impact of these issues, for example on Low Carbon Networks Fund/RIIO-ED1 competition and incentivisation, on the supply chain, and on the wider societal impacts that can be anticipated.

8 Model results

In this section, we discuss the results from both the GB-wide model and synthetic data used in the DNO licence area model. The results are expressed in terms of investment level required for each of the investment strategies, under our modelled scenarios, and considering a number of sensitivities.

We also analyse the solutions that are selected most frequently by the model and discuss the need that this may present for standardisation within a DNO or indeed across the industry with regard to these solutions when they reach their defined "tipping point".

The section includes an analysis of the key differences in results from the WS2 model, and indications of why this difference has occurred.

A reminder of the scenarios modelled is shown in Table 8.1 below:

Table 8.1: Overview of the modelled scenarios

Scenario 0	Scenario 1	Scenario 2	Scenario 3
High domestic decarbonisation	**Domestic decarbonisation to meet carbon budgets**	**Domestic decarbonisation to meet carbon budgets, with less DSR**	**Less domestic decarbonisation (purchase of credits)**
▪ High transport electrification (WS1) ▪ High heat electrification (WS1) ▪ "Gone Green" generation mix (National Grid) ▪ Medium levels of customer engagement with DSR	▪ Medium transport electrification (WS1) ▪ High heat electrification (WS1) ▪ "Gone Green" generation mix (National Grid) ▪ Medium levels of customer engagement with DSR	▪ Medium transport electrification (WS1) ▪ High heat electrification (WS1) ▪ "Gone Green" generation mix (National Grid) ▪ Low levels of customer engagement with DSR	▪ Low transport electrification (WS1) ▪ Low heat electrification (WS1) ▪ "Slow Progression" generation mix (National Grid) ▪ Medium levels of customer engagement with DSR
New for WS3	**As used in the WS2 model**		

Aligned with UK Government guidelines for appraisal[37] and the approach taken for the WS2 report, all results apply an optimism bias of:

- 44% for conventional solutions
- 66% for smart solutions and enablers
- 30% for all operating expenditure[38]

[37] HM Treasury, Supplementary Green Book Guidance on Optimism Bias, http://www.hm-treasury.gov.uk/d/5(3).pdf

[38] Most opex costs are associated with the deployment of smart solutions – costs that are as novel as the solutions themselves (e.g. regular maintenance of a component that has never been deployed in this way before). Optimism bias has been applied, but at a rate that is less than the headline weighting for smart capital investment. In the absence of concrete guidance the 30% figure has been taken as an approximation to factor in both conventional opex (e.g. Communications costs), and new forms of opex (e.g. the costs of data handling for smart meter data and/or DSR contracts). The WS2 model did not apply optimism bias to opex.

The application of optimism bias is essentially a weighting that lifts the effective cost of each solution, to adjust for the systematic tendency of such costs to be underestimated. In the absence of specific evidence regarding optimism bias for distribution network investments, the upper figures for standard and non-standard civil engineering projects have been used.

The model can be set to run up to three investment strategies for any of the input scenarios:

- **Business-As-Usual** – the counterfactual case of only conventional solutions.
- **Top-Down (Smart)** – the smart grid case of conventional and smart solutions, where an upfront investment of enabler technologies is deployed in advance of need, followed by investment as and when networks reach their headroom limits.
- **Incremental (Smart)** – the smart grid case of conventional and smart solutions, where investment only occurs as and when networks reach their headroom limits. Enablers are deployed alongside the solution variants on an incremental basis.

In the case of the Top-Down strategy, the enabling technologies are implemented ahead of need. Assumptions for the installation costs of these technologies is provided in the table below and these costs are spread from 2015-2020 to reflect the likely deployment timescales. Replacement costs, assumed to be half the original costs, are included in this strategy from 2035-2040 to consider end of life (all enablers are assumed to last for 20years).

Table 8.2 Overview of the Enablers implemented in the modelled Top-Down investment strategy

Enabler Name	Top Down Cost (initial[39])	
Advanced control systems	£	2,000,000
Communications to and from devices	£	1,000,000
Design tools	£	300,000
DSR - Products to remotely control loads at consumer premises	£	500,000
DSR - Products to remotely control EV charging	£	1,000,000
EHV Circuit Monitoring	£	600,000
HV Circuit Monitoring (along feeder)	£	400,000
HV Circuit Monitoring (along feeder) w/ State Estimation	£	300,000
HV/LV Tx Monitoring	£	20,000,000
Link boxes fitted with remote control	£	10,000,000
LV Circuit Monitoring (along feeder)	£	50,000,000
LV Circuit monitoring (along feeder) w/ state estimation	£	20,000,000
LV feeder monitoring at distribution substation	£	30,000,000
LV feeder monitoring at distribution substation w/ state estimation	£	20,000,000
RMUs Fitted with Actuators	£	6,000,000
Communications to DSR aggregator	£	500,000
Dynamic Network Protection, 11kV	£	3,000,000
Weather monitoring	£	500,000
Monitoring waveform quality (EHV/HV Tx)	£	4,000,000
Monitoring waveform quality (HV/LV Tx)	£	8,000,000
Monitoring waveform quality (HV feeder)	£	4,000,000
Monitoring waveform quality (LV Feeder)	£	10,000,000

[39] NB. The costs shown here exclude optimism bias.

Smart Metering infrastructure - DCC to DNO 1 way	£	10,000,000
Smart Metering infrastructure -DNO to DCC 2 way A+D	£	20,000,000
Smart Metering infrastructure -DNO to DCC 2 way control	£	50,000,000
Phase imbalance - LV dist s/s	£	10,000,000
Phase imbalance - LV circuit	£	20,000,000
Phase imbalance -smart meter phase identification	£	10,000,000
Phase imbalance - LV connect customer, 3 phase	£	1,000,000
Phase imbalance -HV circuit	£	500,000
TOTAL	**£**	**313,600,000**

Throughout the following section we consider three different categories of financial results:

- **Discounted** – the investment required once a discount factor of 3.5% per year is applied to give a net present value for all investment. In each instance the furthest year where the results are taken from will be stated.
- **Annualised** – discounted costs that are annualised allow for like-for-like comparisons between investment strategies by ensuring that only the costs and benefits accrued by a solution within the modelled period are taken into account.
- **Gross** – the total (non-discounted) investment requirements. This is particularly helpful when assessing the mix of solutions / likely resourcing impact from one RIIO period to the next.

All of the results presented are based on the totex costs, where totex = capital plus the NPV of the opex over 20 years or the life of the solution (whichever is lesser).

8.1 GB Value Chain Results

8.1.1 Results Overview

In this section, the results of the full GB Value Chain model are analysed and presented. This is a social cost-benefit analysis, which incorporates the following types of cost:

- The cost of reinforcing the distribution networks where necessary (by smart or conventional means)
- GB-wide costs of generation and transmission
- customer inconvenience costs associated with the use of DSR
- a value placed upon losses and interruptions on the distribution network

The model provides an estimate of the distribution network reinforcement costs for each year, under each investment strategy. However, simply calculating the present value of these costs can give a misleading picture in the event of a large amount of investment being carried out towards the end of the modelling period. This is because the entire cost of interventions occurring near 2050 will be included in the NPV calculation, but any benefits (in terms of reduced reinforcement costs) that accrue after 2050 will be omitted. A way of correcting this and more accurately assessing the benefits associated with choosing one investment strategy over another is to look at annualised costs. By annualising the cost of investments and then truncating the stream of annualised costs after 2050, it becomes possible to compare the costs of solutions with different lifetimes and years of implementation on a like-for-like basis (see section 6.2.2).

Figure 8.1 below provides the net present value of each "smart" strategy, under each scenario. This is calculated as the difference between the total present value (annualised as described above) of costs under the "smart" strategy and the conventional strategy. Positive values indicate that the smart strategy provides a net benefit to GB, relative to the conventional strategy.

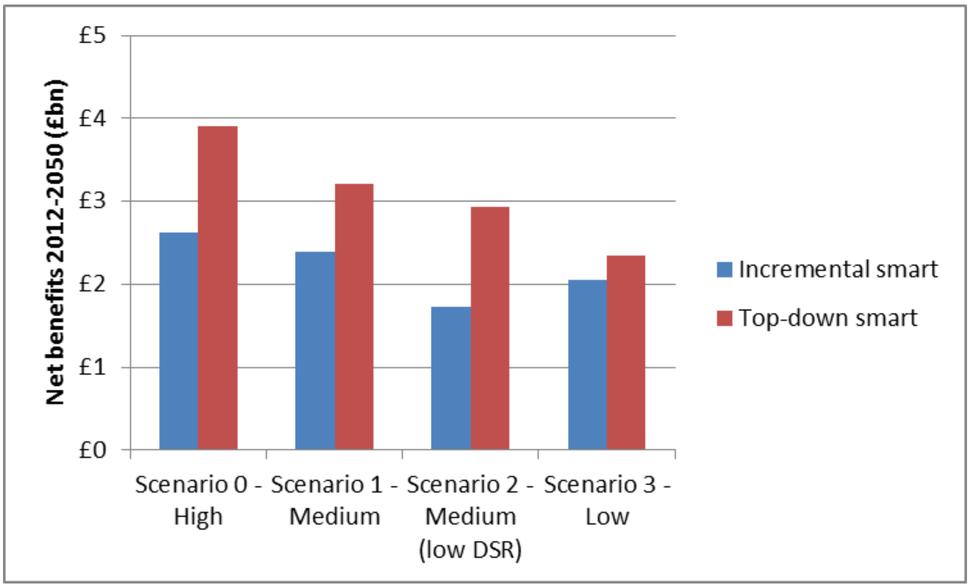

Figure 8.1 NPV of Annualised Investment, 2012-50 [All scenarios, all strategies] (Source: Frontier Economics)

It can be seen that, under all scenarios, the deployment of smart strategies results in a net social benefit to GB, compared to the conventional strategy. This is consistent with the results of WS2 and is unsurprising: the smart strategies involve the optimal mix of all feasible distribution network reinforcement technologies (both smart and conventional), therefore the introduction of more solution options would be expected to lower costs (or, at the extreme, leave them constant).

The net benefits of smart grids are lower under the “Low” LCT penetration (Scenario 3) than they are for the All High (Scenario 0) and Mid (Scenario 1) cases. Scenario 2 is a special case, as this uses the LCT penetrations of Scenario 1, but applies lower levels of DSR: both national (which the network operator effectively does not need to fund) and local (e.g. triggered by the DNO to solve a local constraint). The consequences of this are:

- lower national DSR - the profiles passed from the national model to the DNO model have less smoothing of demand peaks.
- lower DNO DSR - the model needs to select suitable solutions that are not contingent on the use of DSR. These are shown to be more expensive.

The incremental strategy is more affected than the top-down in this instance, as more incremental solutions are being deployed in order to meet the higher LCT penetrations.

However, the level of net benefits is considerably lower than under WS2 - just over £3bn for the top-down strategy under the “medium” scenario, compared with almost £20bn within WS2. To determine what is driving these differences, we have decomposed the NPV within each scenario into the differences within each component of costs. This is shown below for the incremental “smart” strategy (the results for the “top-down” strategy are very similar, except for a greater NPV associated with distribution network reinforcement).

8.1.2 Value Chain Benefits

As with WS2, the costs associated with distribution network reinforcement drive most of the overall NPV. However, these costs are considerably lower here than under WS2 (distribution network reinforcement costs under WS2 were generally within the range £10bn to £20bn across all strategies). This is the primary driver of the differences seen in overall NPV between this model and WS2 (explained further in section 8.4). The sections below examine the components of network investment expenditure in greater detail.

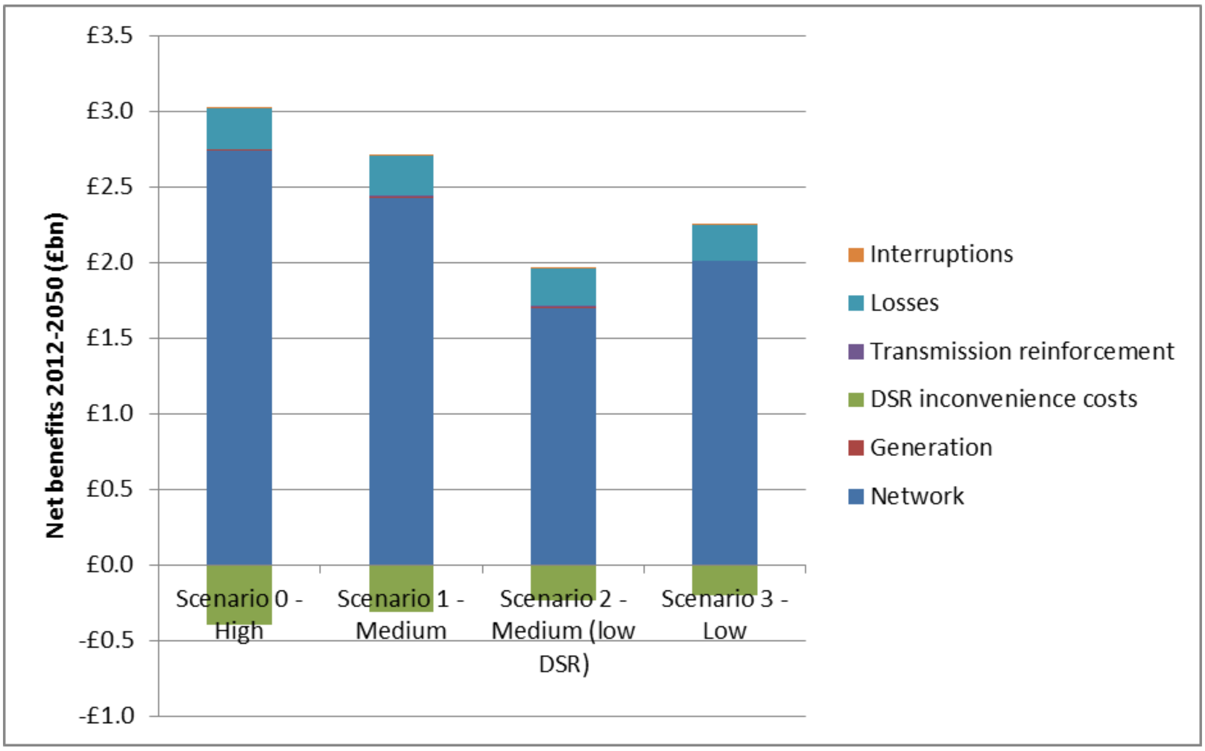

Figure 8.2 Breakdown of NPV of benefits for incremental investment strategy (Source: Frontier Economics)

Like the WS2 model, generation and transmission costs vary little between the "smart" and conventional strategies. There are highly significant gross costs associated with generation and transmission. However, these will generally be very similar across each of the investment strategies due to our assumptions regarding smart meters, which are set out in Section 1.3.1. Since nationally-led DSR is assumed to exist in the counterfactual conventional world, the only "smart" solution which could affect generation and transmission costs is additional localised DSR carried out by DNOs.

The additional DSR "inconvenience" costs under the smart strategies are greater than under the WS2 model, which reflects the increased inconvenience cost per kW assumptions used within this model (described below).

8.1.3 Nationally-led DSR

A required input to the model is the "inconvenience" cost borne by customers for shifting a kW of load. This value can be thought of as the minimum amount that suppliers or DNOs would need to compensate customers in order for them to just accept having their consumption patterns changed (though DSR) and reflects the real resource costs to consumers of this inconvenience. This is used to determine the amount of DSR (both national and local) to deploy: lower inconvenience costs will generally lead to a higher level of DSR. This is a parameter which can vary by technology as there may be a higher inconvenience cost associated with moving some types of load, such as appliances, than others (for example, storage heaters).

Little research has been carried out into how acceptable different types of load shifting are to consumers – this is an area where input from LCNF projects will be particularly valuable. One way of obtaining a general range for these costs is to consider the tariff differentials that currently exist to facilitate load-shifting. If such tariffs were set at just the level sufficient to encourage customers to move their demand,[40] then the differential between peak and off-peak (the bill saved by consumers shifting a kW of load) would approximate the inconvenience costs of them doing so.

The current differential between the peak and off-peak rates within an Economy 7 tariff is approximately 10p/kWh (the peak day rate is around 300% of the night rate). Lower differentials between peak rates and shoulder periods are seen in other tariffs that have been trialled for DSR purposes (average differentials of approximately 200% are common). However, the difference between peak and off-peak rates may be expected to rise over the next decade as the value from encouraging consumers to engage in DSR to avoid peak periods is expected to increase (for example due to expected increases in commodity costs which will increase the differential between peak and off-peak generation costs). As a result, additional forms of DSR with higher levels of customer inconvenience may be employed.[41]

Within the model, a cost per kWh shifted of 20p has been assumed.[42] Even this is sufficiently high to prevent significant amounts of DSR taking place. The graph below shows modelled national peak demand on the distribution network during the 2030 winter peak, both before and after the application of DSR (at both the national and local levels).

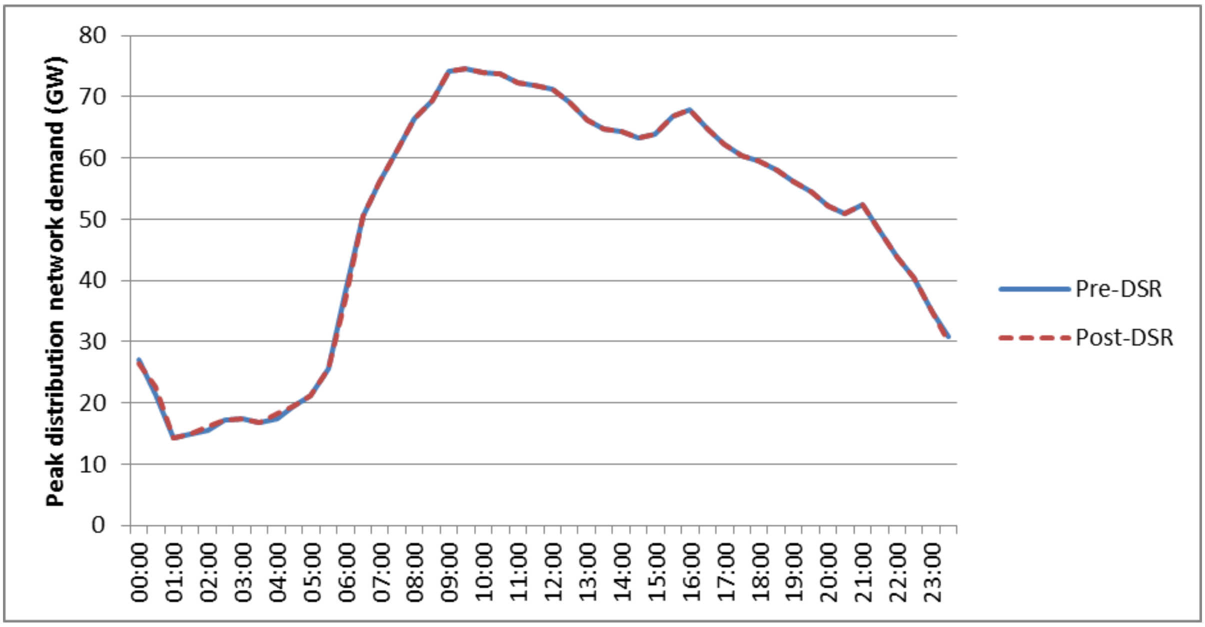

Figure 8.3 Winter peak load in 2030, before and after DSR, cost set at 20p/kWh (Source: Frontier Economics)

Additional sensitivities were conducted with DSR costs set at 2p per kWh (which is much closer to the costs used within WS2) and £2 per kWh. Unsurprisingly, at £2 no DSR occurs during 2030. However, with DSR costs reduced to 2p, higher levels of DSR occur, as shown below.

[40] In practice, many more factors will affect the level of tariffs. However, in the absence of further evidence, this at least provides a broad estimate of the order of magnitude such costs may take.

[41] At present, much of the load shifting incentivised by Economy 7 tariffs takes place through storage heaters. By their nature, one would expect consumers to be relatively indifferent to the time at which their storage heaters are drawing load. By contrast, the use of DSR with other appliances may be more noticeable to consumers.

[42] Since the model works with half-hour periods, this is entered as £0.1 within the model.

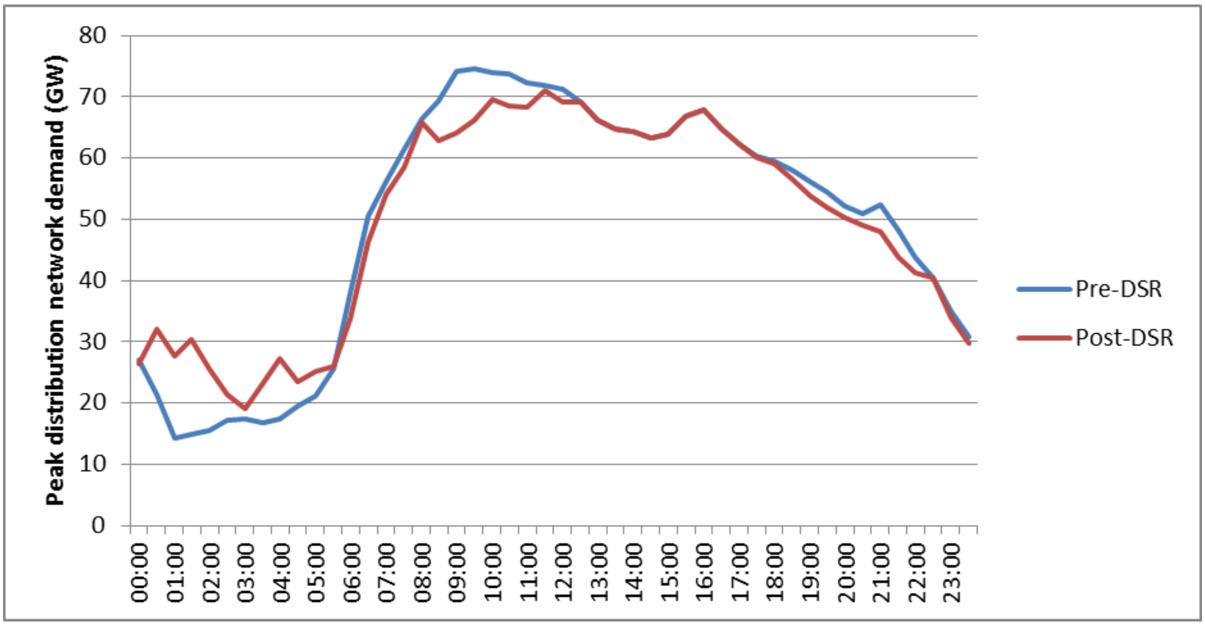

Figure 8.4 Winter peak load in 2030, before and after DSR, cost set at 2p/kWh (Source: Frontier Economics)

8.2 GB Networks Results

In this section, the results of the GB wide DNO model are analysed and presented, covering the following key aspects:

- Annualised results
- Present Value results
- Investment profiles
- Solution selection
- The effects of identification and action at the 'tipping' points

8.2.1 Annualised Results

As explained in section 6.2.2, when comparing the overall net benefits of strategies, it is important to look at annualised costs.

Figure 8.6 and Figure 8.5 below illustrate the annualised investment profile and the net benefits arising by investing in a smart strategy.

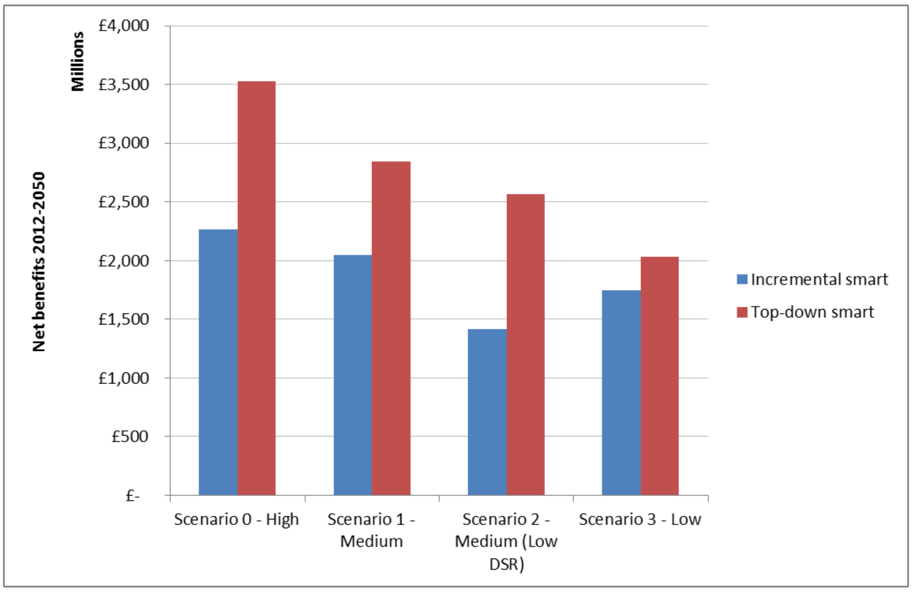

Figure 8.5 Annualised NPV benefits for DNO investment by scenario under default assumptions

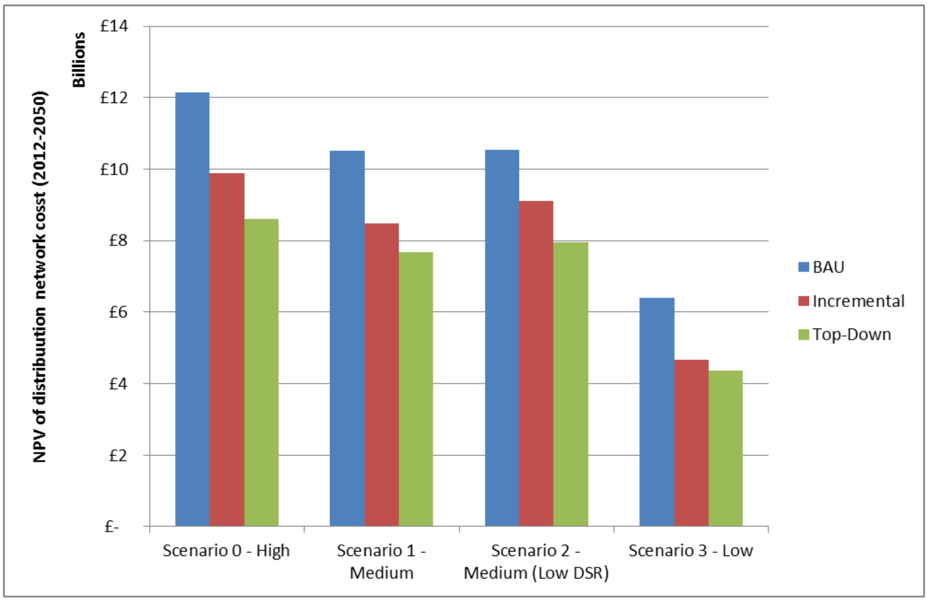

Figure 8.6 Present Value of Annualised Investment, 2012-50 [All scenarios, all strategies]

8.2.2 Present Value Results

As discussed in section 6.2.2, it may also be interesting to compare the overall expenditure to 2050 associated with each strategy. To do this, discounted NPVs of the costs under each strategy can be viewed.

The net reduction in cost incurred before 2050 of the two smart grid investment strategies are shown as relative to the conventional strategy in Figure 8.7 below. In all instances, there is reduction in costs incurred before 2050 associated with both smart strategies for the modelled scenarios.

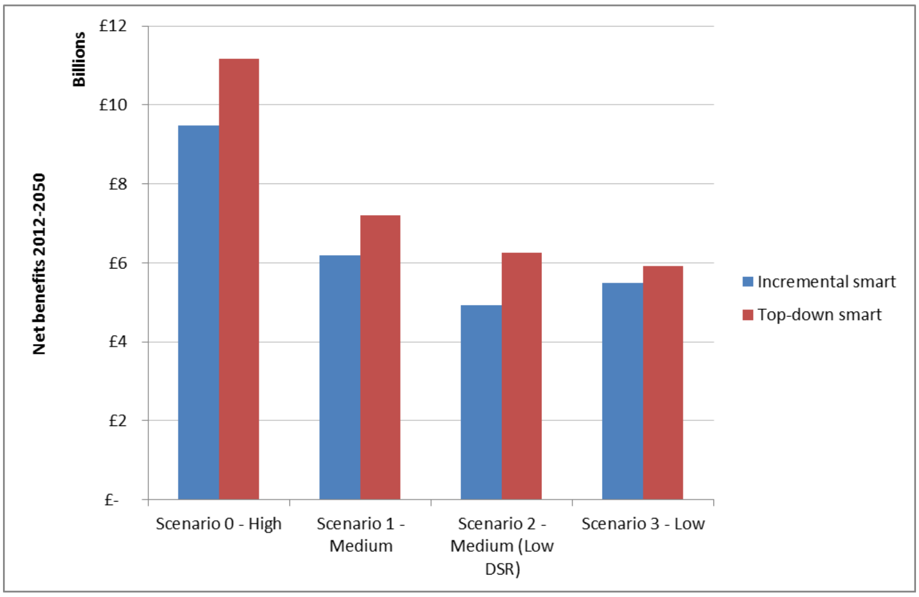

Figure 8.7 **Net savings in DNO investment by scenario, under default assumptions**

The results below show the present value to 2050 of the costs for each scenario and investment strategy.

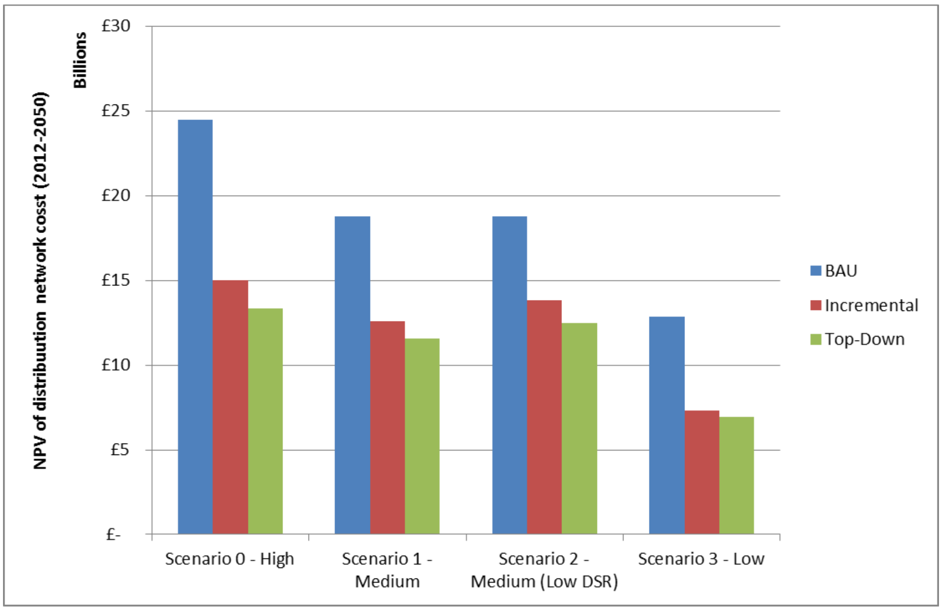

Figure 8.8 **Summary of present value of gross totex of distribution network investment (2012-2050)**

These results show a reduction in costs incurred before 2050 associated with applying the smartgrids investment strategy over using solely conventional solutions for all modelled scenarios. This is based on modelling results out to 2050, with the Incremental and Top-Down investment strategies consistently representing overall investment levels of the order of 50-75% of the Business-As-Usual strategy. In all scenarios, the top-down smartgrid investment strategy is proving to have a lower cost than that of incremental. Though, particularly in the case of Scenario 3, the difference is small and within the range of the model’s uncertainty.

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 options to choose from when selecting solutions within these strategies.

The difference between Scenarios 1 and 2 is driven by the assumption of a lower public acceptance of DSR in Scenario 2. This principally affects the level of nationally-driven DSR, which corresponds to different profiles passed from the Value Chain model (i.e. looking at the national generation capacity required to meet the demand) to the DNO model. As nationally-driven DSR, such as that used to flatten the EV charging demand, tends to align with the needs of the distribution network (flattening peaks in the early evening) it helps to reduce DNO network constraints. This nationally-driven DSR is assumed to be facilitated by smart meters in the modelling, and is present in the Business-as-usual strategy case as well as in the smart grid strategies. There is therefore no additional cost to the DNO associated with delivering it. A reduced use of nationally-driven DSR will drive the deployment of more DNO solutions to solve headroom issues. There is limited change in BAU costs between Scenarios 1 and 2, largely as most conventional solutions release significant amounts of headroom, and investment taken for Scenario 1 also meets the demands of Scenario 2.

The lower investment results for Scenario 3 are linked to the low numbers of EVs, HPs, PVs and DG in this scenario.

As would be expected, when the present value of investment costs is calculated over shortened time horizons, the model produces slightly different results (Figure 8.9). [Since the penetration of low carbon technologies is much lower in the period to 2030 than it is to 2050, DNO investment costs are lower across the board and the net benefits of smart grids are also lower]. Looking out to the end of the RIIO-ED2 period, a top-down strategy is shown to give rise to a dominant benefit in all cases. It should be noted that the top-down investment strategy makes use of a number of enabling technologies with assumed costs and an assumed lifetime of twenty years before they require replacement. In order to more accurately determine the difference in benefits realised between the two smart strategies, more accurate information pertaining to the cost of these enabling technologies would be necessary.

Within the RIIO-ED1 period, the costs of upfront investment of the top-down strategy are not recovered in the relatively short timescales, and at the lower penetrations of low carbon technologies.

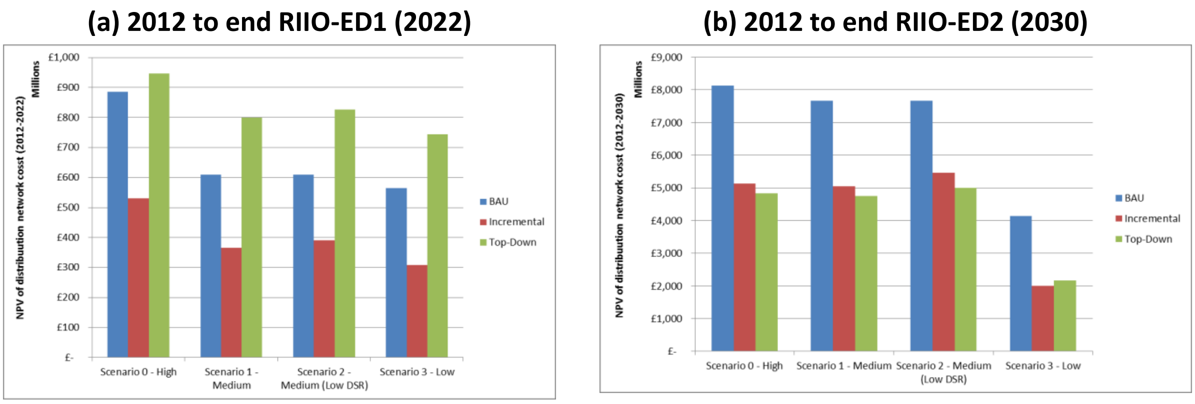

Figure 8.9 Comparison of investment strategies

The scenarios from WS1 all show a similar growth for EVs and HPs over the first 8-10 years of the scenarios. This is driving similar investment requirements across the four modelled scenarios for, particularly the RIIO-ED1 period. Out to 2030 and beyond, the scenarios diverge which result in substantially different investment profiles.

8.2.3 Investment profiles

The model can produce an array of data. The following analysis has been performed on two of the more interesting, and different, scenarios, those of:

- **Scenario 1 (Mid Case)** – Medium uptake with domestic decarbonisation set to meet carbon budgets
- **Scenario 3 (Low Case)** – Low uptake with less domestic decarbonisation (purchase of credits)

The results of these are discussed below.

Scenario 1 – Mid Case

Figure 8.10 shows the investment highlighted from the model over successive RIIO price control periods.

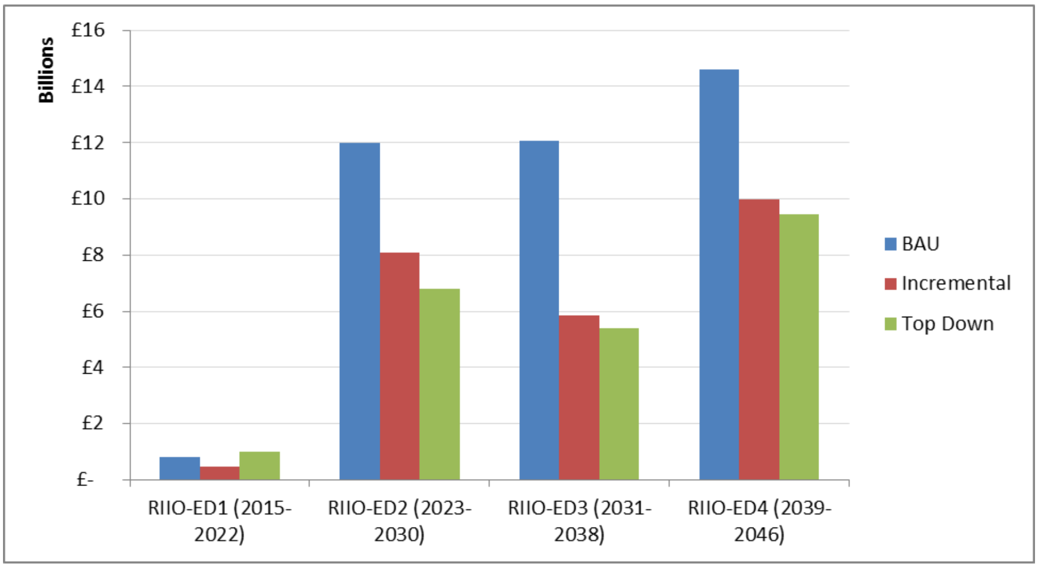

Figure 8.10 Breakdown of totex investment for Scenario 1 in 8-year blocks, as aligned to GB electricity distribution price control periods

For this scenario, investment ramps up rapidly between the RIIO-ED1 and RIIO-ED2 period, as the numbers of low carbon technologies increase. This suggests that the current networks are relatively resilient to low penetrations of low carbon technologies, but by the RIIO-ED2 period, more networks start to run out of capacity, triggering more widespread investment.

For both of the smart investment strategies, investment averages to around £7 - 8bn for the 8-year price review periods from 2023. The conventional only strategy shows an average of approximately £13bn for the 8-year price review periods from 2023. The top-down smartgrid investment strategy is proving to be the most beneficial over the longer term, the marginal reduction in RIIO-ED3 aligns with the end of life assumptions (15 years) and associated reinvestment of the enabler technologies.

The GB results for the cumulative investment for Scenario 1 are shown in Figure 8.11 and Figure 8.12.

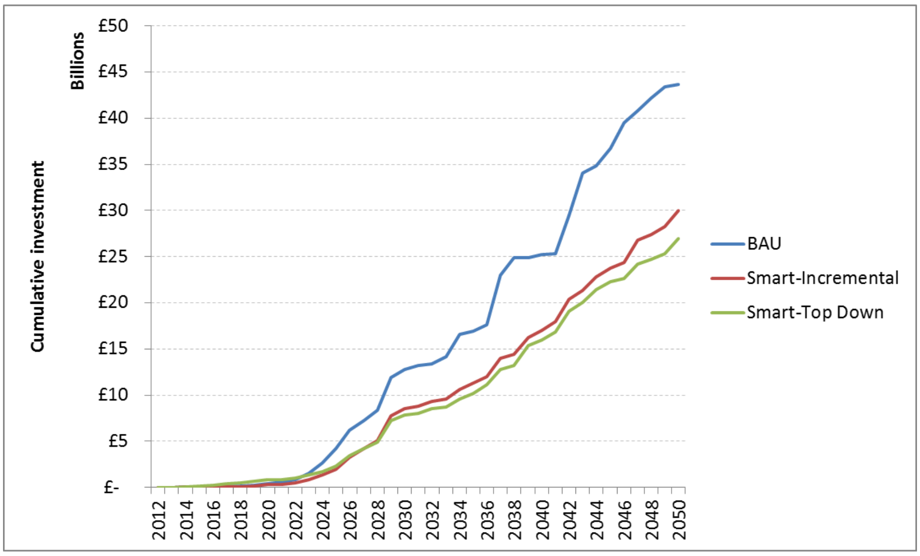

Figure 8.11 Summary of Gross Cumulative Investment, 2012-50 (Scenario 1, all strategies)

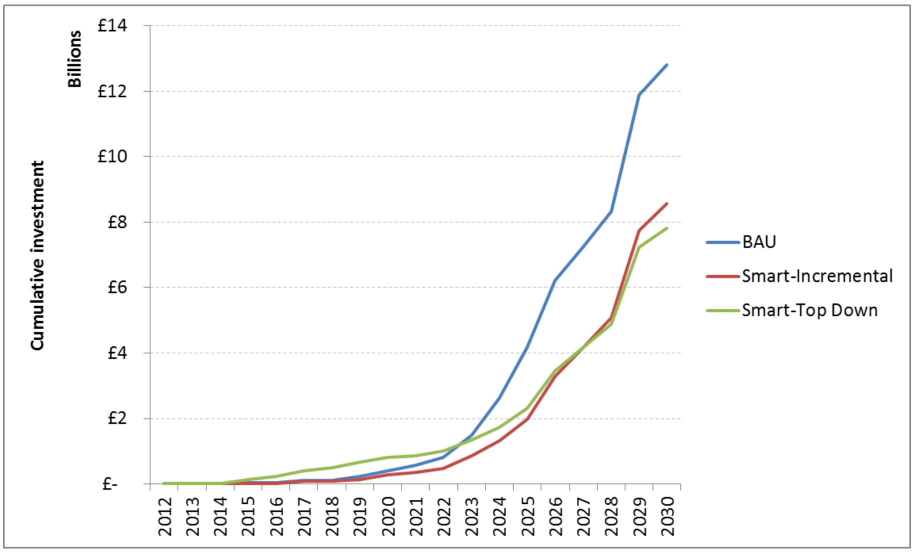

Figure 8.12 Summary of Cumulative Investment, 2012-30 (Scenario 1, all strategies)

Low Case – Scenario 3

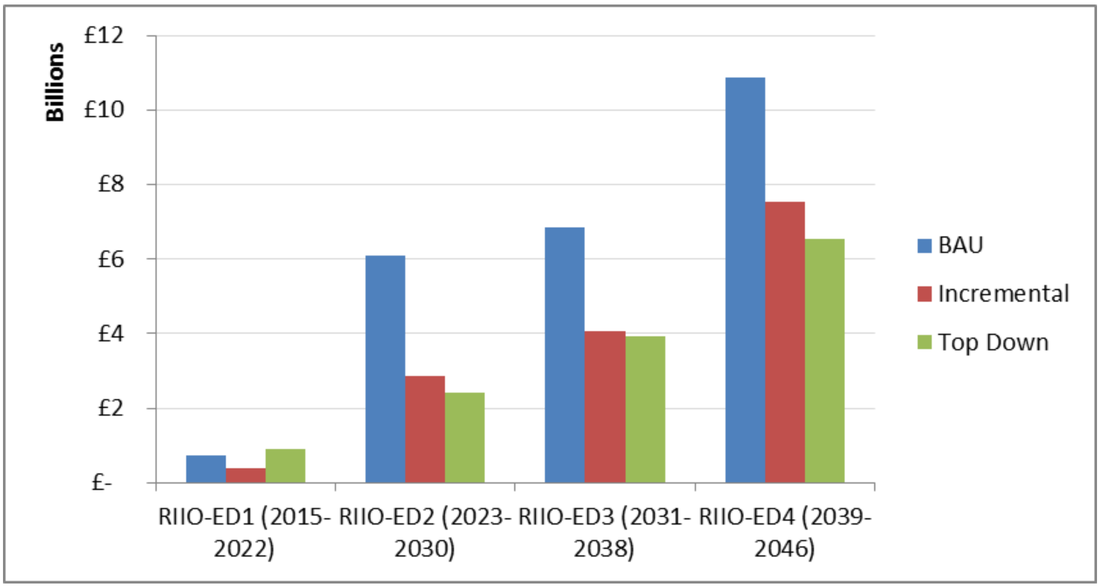

Figure 8.13 Breakdown of investment for Scenario 3 in 8-year blocks, as aligned to GB electricity distribution price control periods

In this lower scenario, investment, whilst lower, is still significant, particularly during the RIIO-ED2 period. This is showing how the model is sensitive to the lower penetrations of LCTs, particularly where clustering occurs. Despite the lower penetrations of LCT, the top-down smartgrid investment strategy remains as the optimum for the longer term.

Again, the benefits are reduced in the RIIO-ED3 period as this coincides with reinvestment of enablers installed from 2015-2019 as they reach end of life.

This output will be sensitive to the trigger thresholds for reinforcement that are set (the percentage of rating that assets can be loaded to before being reinforced); i.e. if the thresholds were higher, some of the ED2 investment would be deferred to ED3.

The GB results for the total investment for each year for Scenario 3 are shown below.

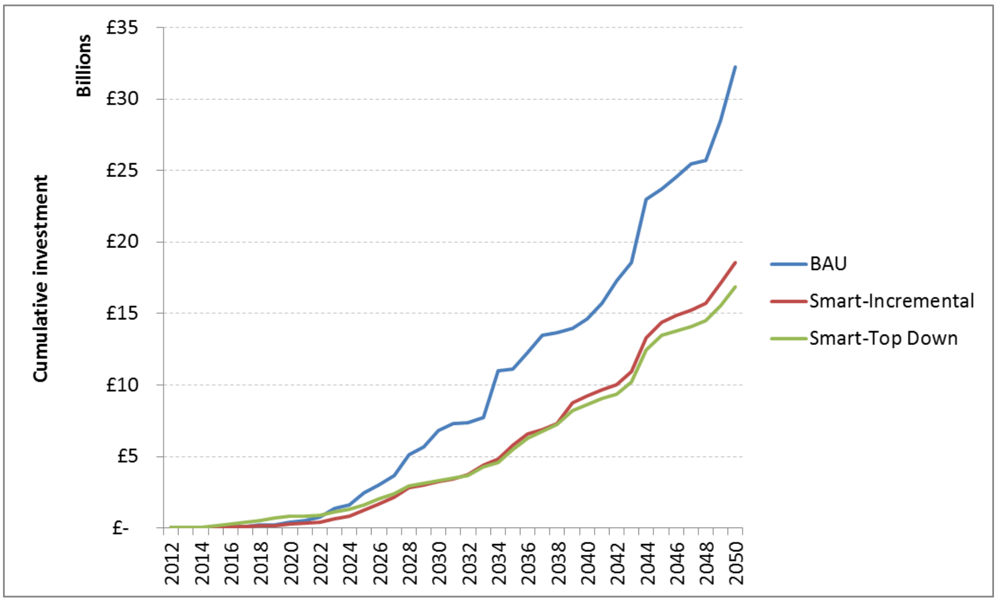

Figure 8.14 Summary of Gross Annual Investment, 2012-50 (Scenario 3, all strategies)

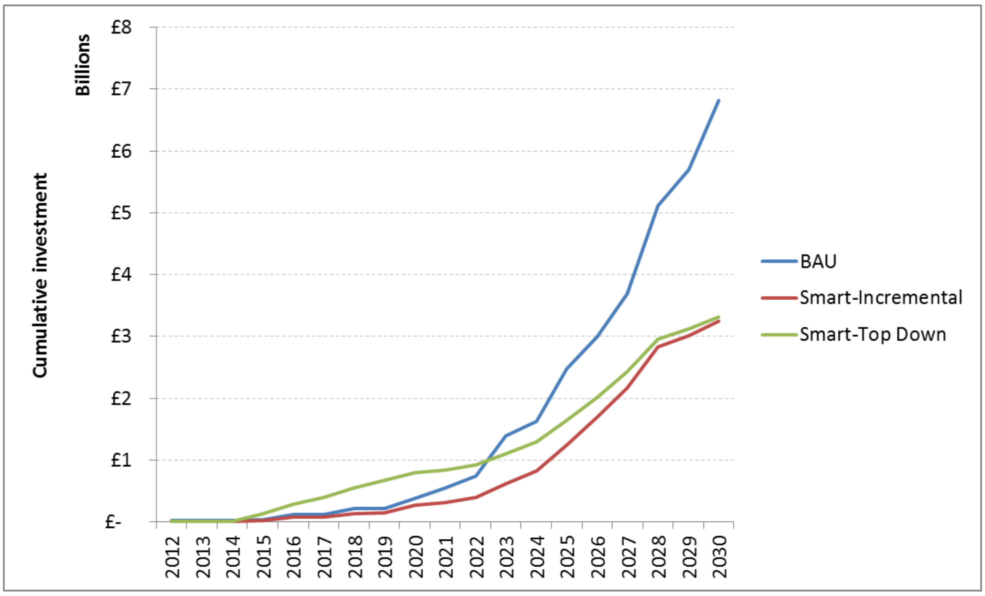

Figure 8.15 Summary of Investment, 2012-30 (Scenario 3, all strategies)

8.2.4 Selection of Solutions

This section provides an overview of the solutions chosen by the model. These types of results can be analysed for any of the scenarios or investment strategies. For the sake of brevity, only the results of Scenario 1 are presented and discussed below.

Overview

Figure 8.16 to Figure 8.18 over show the undiscounted outputs from the model by solution type.

As would be expected, for the BAU investment case, only conventional solutions are applied.

For both Smart investment strategies, the model is selecting a blend of both conventional and smart solutions. This mix (approximately 66% smart to 33% conventional) limits the network headroom released to that which is required, rather than applying the comparably larger headroom release options offered from the limited conventional solution set and their associated 'lumpy' investments. The net is an optimised spend profile.

The differences in the deployment of enablers between incremental and top-down show the efficiencies that would be realised from up-front and coordinated deployment of enablers, which are then switched on as and when necessary, rather than the drip feeding of enablers as new smart solutions are deployed.

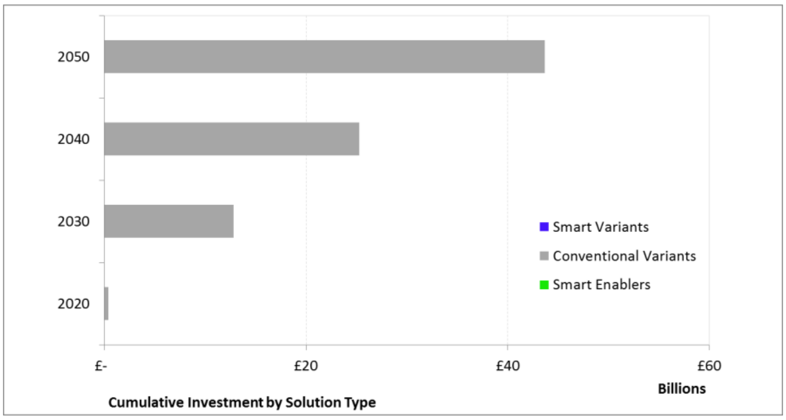

Figure 8.16 Overview of solutions selected (cumulative, undiscounted): BAU Investment strategy only (Scenario 1)

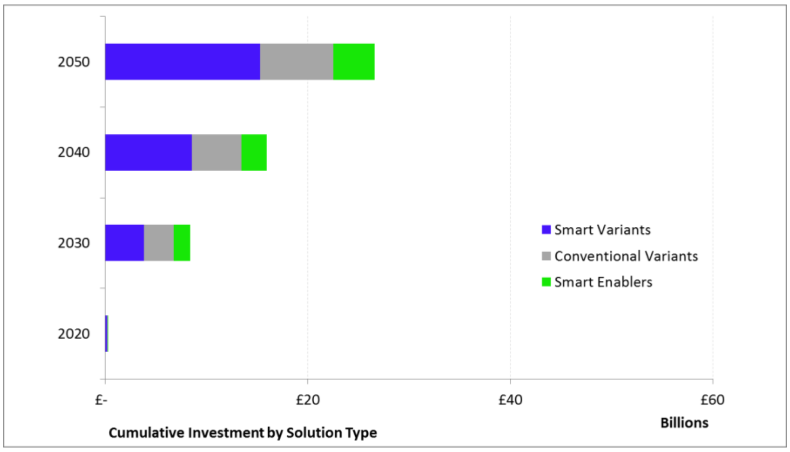

Figure 8.17 Overview of solutions selected (cumulative, undiscounted): Smart-Incremental Investment strategy only (Scenario 1)

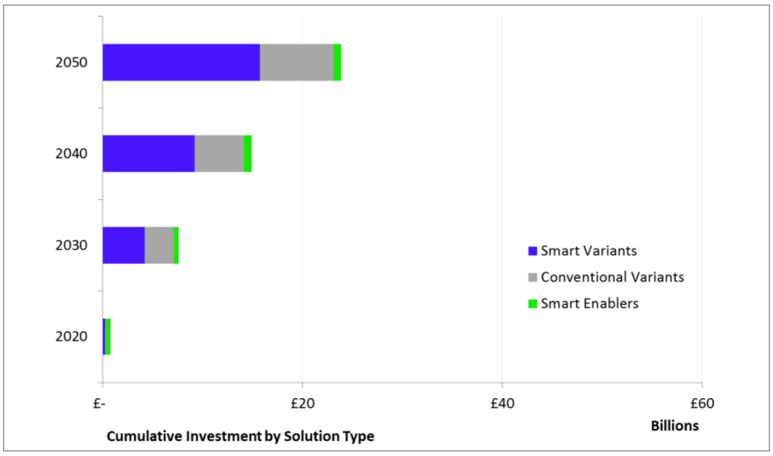

Figure 8.18 **Overview of solutions selected (cumulative, undiscounted): Smart-Top-Down Investment strategy only (Scenario 1)**

By Representative Solution

Figure 8.19 to Figure 8.21 have been provided to show the undiscounted outputs from the model by representative solution. NB the breakdown by variant solutions have not been provided in this results section for brevity.

Note also that for ease of reading, the scale in each of the following three figures is different.

Some points to note:

- The selection between solutions is based on the calculation of the merit order on an annual basis, to account for different costs, driven by assumptions of the solution cost curve.
- The merit stack is sensitive to the starting assumptions for each of the solutions: installed cost, operating cost, disruption cost, solution life expectancy, etc. As mentioned in Section 5.5.5, this is the first time many of the solutions, included in this model, have been categorised in this manner. The factors are therefore expected to change as the results of real trials / deployments become available, thereby improving the results of the model.
- Where there are large differences in costs between solutions, the model is consistently selecting the cheapest solution (by its merit order cost). This is meaning that some solutions are picked often, some only in later years [as their costs fall away due to the effects of the applied cost curve], or some never. Solutions that are never selected as discussed further after Figure 8.18.
- The ancillary cost factors included in the cost function (e.g. disruption cost £, cross network benefits cost £) are not directly brought out in the model results. Therefore societal costs by way of disruption (e.g. for road closures to facilitate the laying of new LV underground circuits) would be additional costs to those presented in this report.

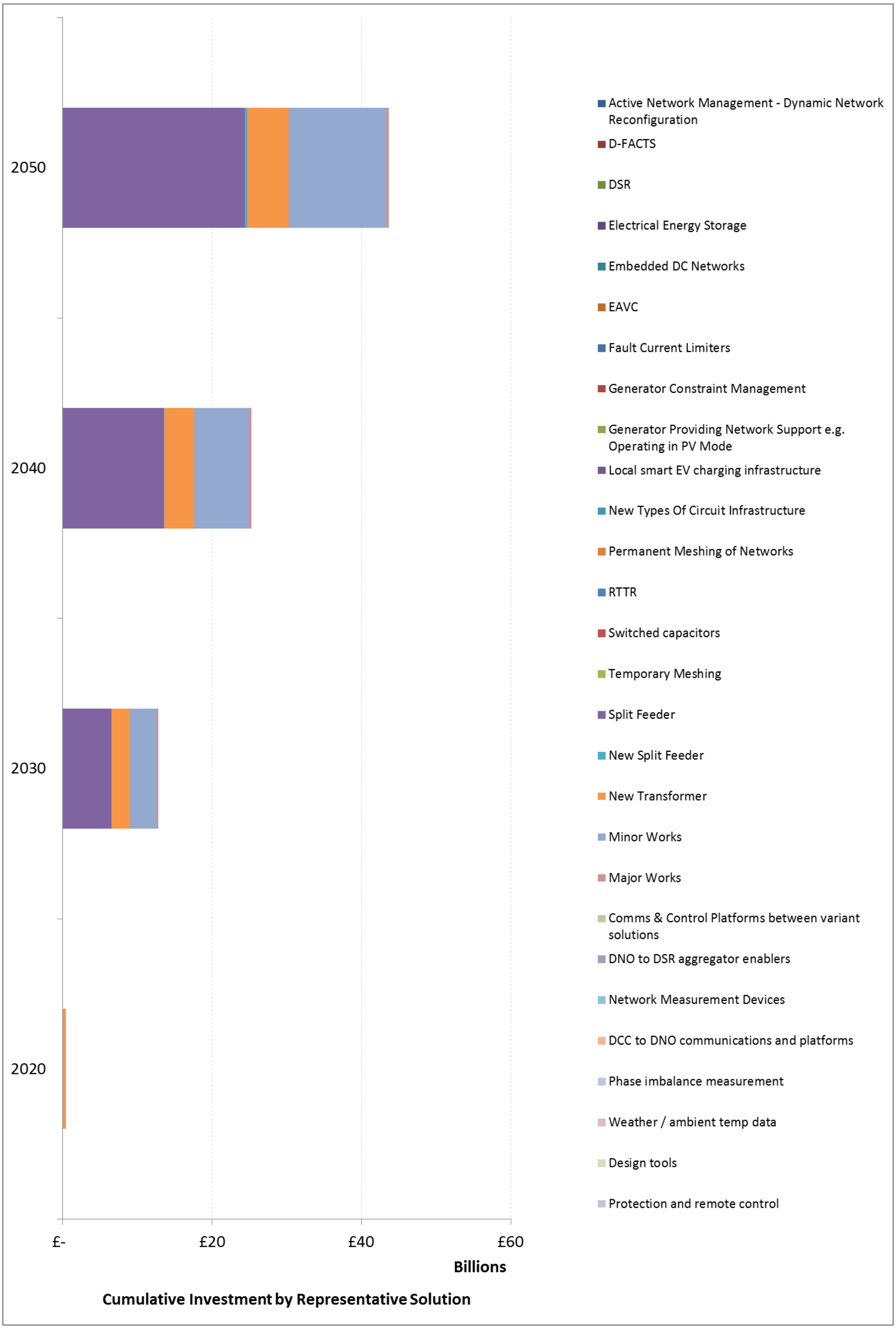

Figure 8.19 Breakdown of Representative solutions selected (cumulative, undiscounted): BAU Investment strategy only (Scenario 1)

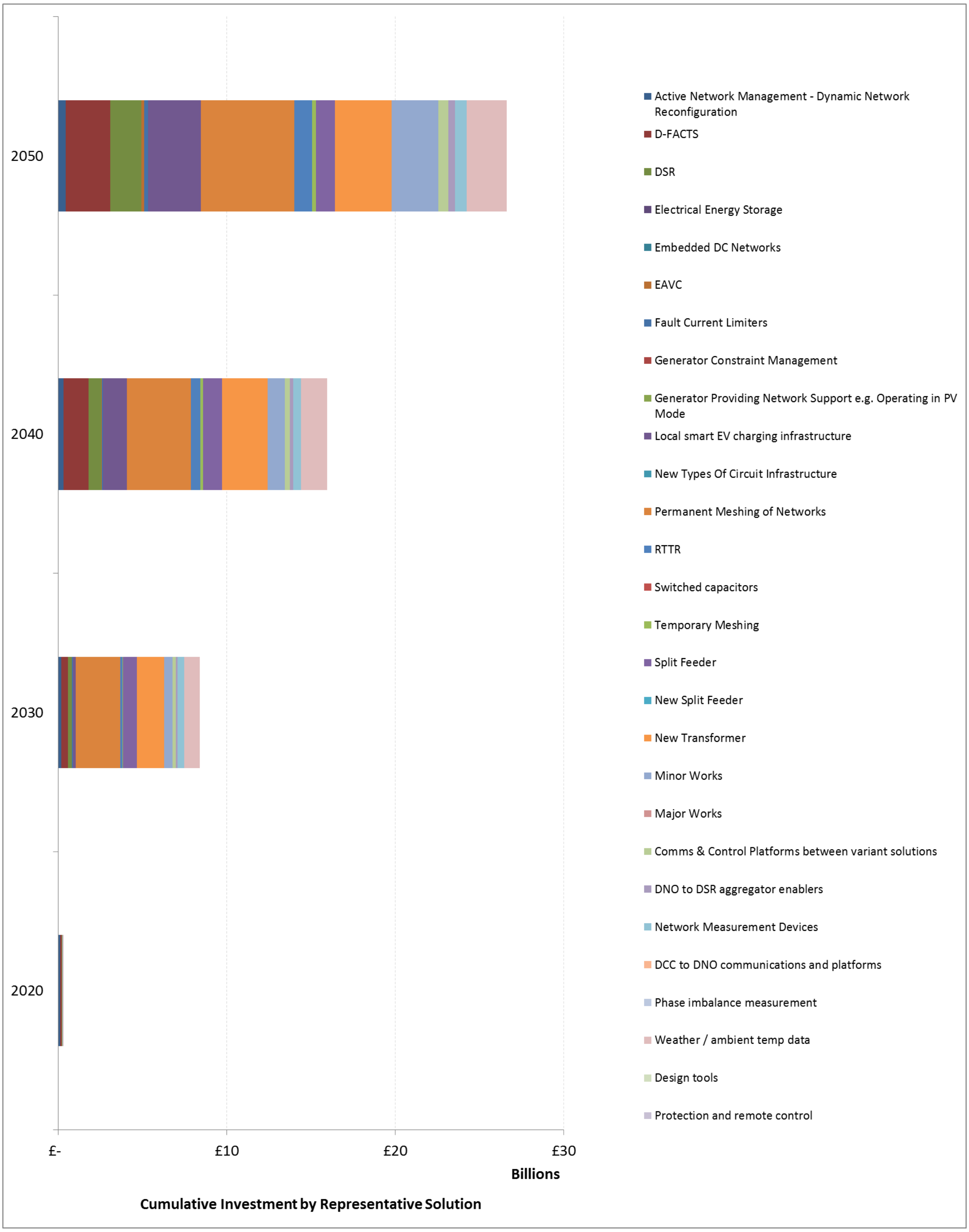

Figure 8.20 Breakdown of Representative solutions selected (cumulative, undiscounted): Smart-Incremental Investment strategy only (Scenario 1)

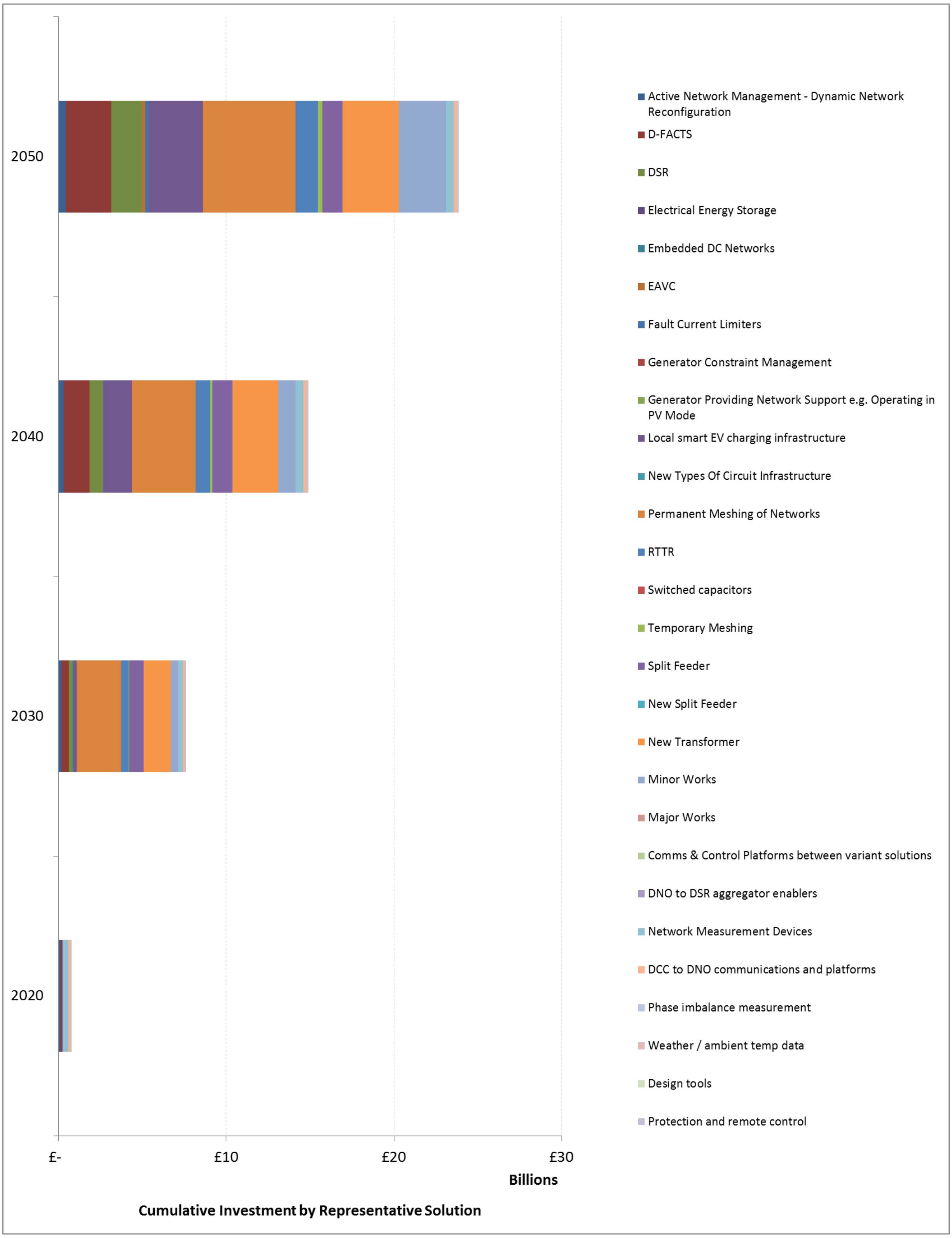

Figure 8.21 **Breakdown of Representative solutions selected (cumulative, undiscounted): Smart-Top-Down Investment strategy only (Scenario 1)**

A breakdown of the solutions for each of the investment strategies has been drawn out in the Tables below (all decimal places have been removed for ease of reference). For further clarity, any solutions with less than 0.5% of the annual investment (by 2050) have been removed from the tables. It is noted that even a small fraction here, say 0.1% would represent a significant level of expenditure given that this may be 0.1% of a £26.6bn investment programme (£26.6m). For further clarity, the text has been coloured to show the differences between:

- conventional solutions
- smart solutions
- enablers

Table 8.3 Breakdown of solution selection from the model for the Business-As-Usual investment strategy (Scenario 1)

Solution	2020	2030	2040	2050
Split Feeder	3%	51%	54%	56%
New Split Feeder	0%	0%	0%	1%
New Transformer	80%	19%	16%	13%
Minor Works	5%	28%	29%	30%
Major Works	11%	2%	1%	1%
Cumulative (undiscounted) Investment (£)	**£400m**	**£12,800m**	**£25,250m**	**£43,671m**

Table 8.4 Breakdown of solution selection from the model for the Smart Incremental investment strategy (Scenario 1)

Solution	2020	2030	2040	2050
Active Network Management - Dynamic Network Reconfiguration	35%	2%	2%	2%
D-FACTS	35%	5%	9%	10%
DSR	0%	3%	5%	7%
EAVC	0%	0%	0%	1%
Fault Current Limiters	1%	1%	0%	1%
Local smart EV charging infrastructure	1%	2%	9%	12%
Permanent Meshing of Networks	2%	32%	24%	21%
RTTR	3%	2%	3%	4%
Temporary Meshing	0%	1%	1%	1%
Split Feeder	1%	10%	7%	4%
New Transformer	5%	19%	17%	13%
Minor Works	9%	6%	6%	10%
Comms & Control Platforms between variant solutions	0%	2%	2%	2%
DNO to DSR aggregator enablers	0%	1%	1%	1%
Network Measurement Devices	3%	5%	3%	3%
Weather / ambient temp data	5%	11%	10%	9%
Cumulative (undiscounted) Investment (£)	**£290m**	**£8,391m**	**£15,955m**	**£26,625m**

Table 8.5 Breakdown of solution selection from the model for the Smart Top-Down investment strategy (Scenario 1)

Solution	2020	2030	2040	2050
Active Network Management - Dynamic Network Reconfiguration	13%	2%	2%	2%
D-FACTS	13%	6%	10%	11%
DSR	0%	3%	5%	8%
EAVC	0%	0%	0%	1%
Fault Current Limiters	0%	1%	0%	1%
Local smart EV charging infrastructure	0%	2%	11%	14%
Permanent Meshing of Networks	1%	35%	25%	23%
RTTR	1%	6%	6%	6%
Switched capacitors	0%	0%	0%	0%
Temporary Meshing	0%	1%	1%	1%
Split Feeder	0%	12%	8%	5%
New Transformer	2%	21%	18%	14%
Minor Works	3%	5%	7%	12%
Comms & Control Platforms between variant solutions	1%	0%	0%	0%
Network Measurement Devices	39%	4%	3%	2%
DCC to DNO communications and platforms	17%	2%	1%	1%
Phase imbalance measurement	5%	1%	0%	0%
Protection and remote control	4%	0%	0%	0%
Cumulative (undiscounted) Investment (£)	**£787m**	**£7,602m**	**£14,918m**	**£23,865m**

The solutions described here are not necessarily selected uniformly across all of the feeder types within the model. For example, DSR is rarely selected for LV feeders supplying the Central Business District, but is often picked for feeders supplying terraced streets.

A note of caution with regard to particular technology solutions:

- the modelling in the report should be regarded as indicative-only for specific technologies
- we can expect particular solutions to move in the merit order as they mature and as network conditions develop
- in practice, technology solutions should be adopted on their individual and local merits and not as a conclusion from the high-level modelling presented here
- individual business cases for technology investment will remain key to decision-making
- the model described in this report may be used to inform longer term technology strategies but will require careful sensitivity and tipping point analysis
- incremental movement in the merit order of solutions as technologies mature is unlikely to have a significant effect on the headline conclusions

Other factors

The model does not consider the societal costs of disruption associated with the deployment of solutions directly in its output[43]. It however helpful to understand the results of the model in non-financial terms, such as a comparison in the amount of overhead line or underground cable deployed (Figure 8.22).

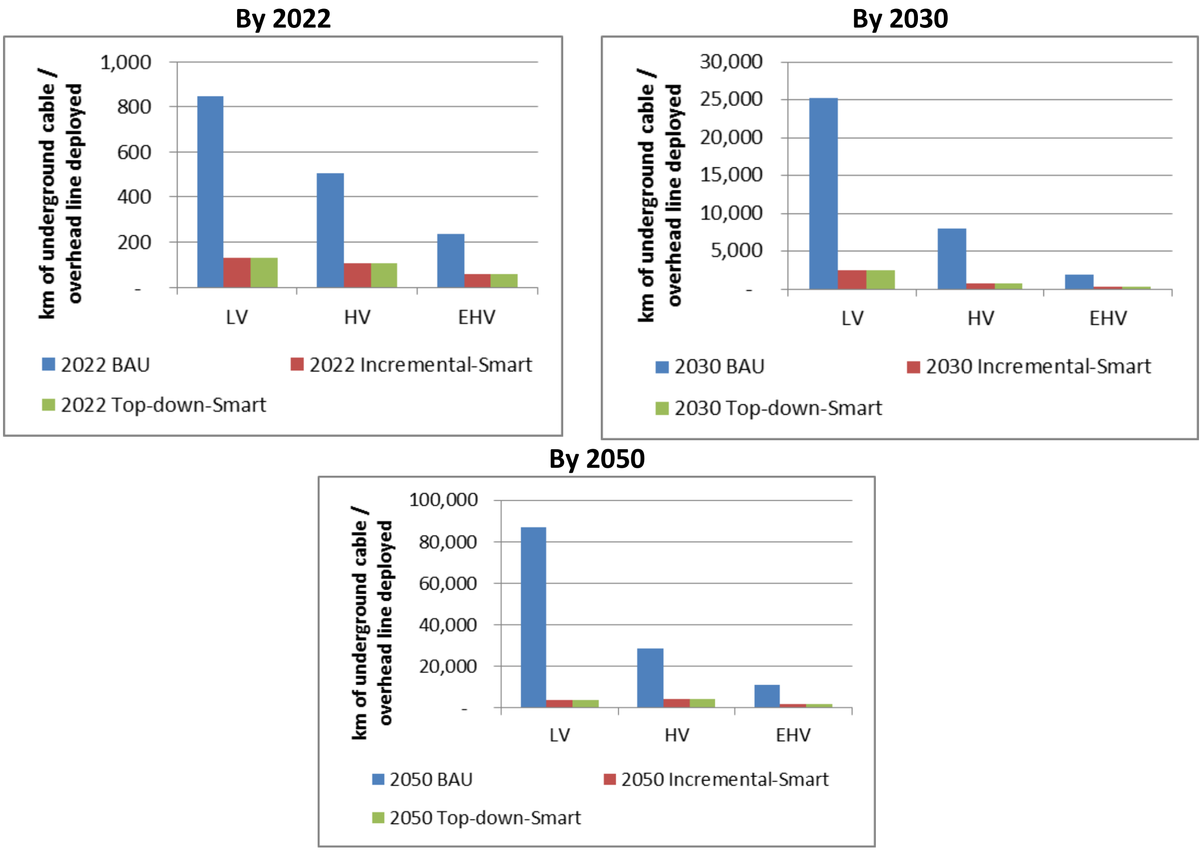

Figure 8.22 Summary showing the differences in the amount of underground cable and overhead line selected for deployment between the three investment strategies (all based on Scenario 1)

Differences between the three scenarios can clearly be seen, and are exacerbated as volumes of LCTs increase by 2030 and beyond. In the conventional (BAU) strategies, the options for investment are limited to new circuits or new transformers. It is natural that both are deployed, and at scale, as the network is put under more pressure with the increase in LCTs.

In the cases of both smart investment strategies, the model is selecting other solutions alongside conventional reinforcement. The result is a significant reduction in the amount of circuits that would need to be replaced, purely to accommodate uptake in LCTs[44].

[43] Disruption is factored into the model as a bias applied to the dynamic merit order, in order to weight less disruptive solutions (such as measurement devices in a substation) over more intrusive solutions (such as the laying of a new cable down a street).

[44] Once again, this model treats the challenge posed by the uptake of LCT in isolation to other forms of network investment (e.g. load related or non-load related). It is recognised that some synergies may be borne of a more holistic strategy.

Other solutions

Some of the representative solutions are notable by their absence from the results under the default GB settings:

- **Storage:** Electrical energy storage is not being selected, principally due to its high cost, which when compounded with the 66% optimism bias, is giving it a low ranking in the merit order. Sensitivities have been run in Section 8.3.9, showing how the solution is selected when the costs are reduced to levels comparable with other smart solutions.
- **Generation Constraint Management**: Generation constraint management is increasingly applied to pockets of the network today, principally to address load-related reinforcement associated with generation connections. The WS3 GB model provides an averaged overview of distribution networks across the country. At EHV and HV there is insufficient granularity to have a single circuit to synthesise a heavily loaded feeder dominated by generation (e.g. as may be seen in parts of Scotland (islands, highlands and borders), Cumbria, Mid-Wales, etc.). As generation clustering is not being considered in the national model, this is affecting where this solution would deployed[45]. At LV, it is assumed that Constraint Management would only be applied to larger three-phase connected generation types, located in Central Business Districts, Town Centres and Retail Parks. The opex cost applied against this solution makes this a relatively expensive option - if costs were to be reduced, this solution would be deployed on a more regular basis.
- **Generation in PV mode**: As per generation constraint management above.
- **New types of infrastructure**: The new types of infrastructure are being treated as “beefed-up” versions of new circuits. As the costs of these infrastructure types are assumed to be higher than the conventional alternatives, they are tending to be placed lower in the merit order, and despite releasing more headroom, they are not being selected by the model. If the costs were to be reduced, or the investment look-ahead period were to be increased from 5-years, this solution would be deployed more readily.
- **Switched capacitors**: The costs included in the model for this solution have been taken from a small number of real projects. It is noted that the costs, whilst consistent with the WS2 model, are high compared to many of the other smart solutions. This is giving this solution a low ranking in the merit order, consequently other solutions (e.g. D-FACTS) are being picked above switched capacitors.

[45] A generation heavy circuit has been provided, by way of example, in the synthetic DNO network.

8.2.5 Tipping Point Results

Following on from Section 7, it is helpful to understand the systems' implications (and benefits) by using the model to ascertain when certain solutions have reached deployment 'tipping points'. The model has been set to flag when solutions hit the following financial trigger points[46]:

- EHV - £50m
- HV - £30m
- LV - £20m

The use of tipping points is made more helpful where it enacts a response. For the purpose of this report, a blunt assumption has been taken that after reaching the tipping point a reduction in cost of 10% is achieved (on the basis that procurement efficiencies, other income streams etc are achieved at this stage). The tipping point assessment only applies to the smart solutions as the conventional solutions have been in place for decades, and refined over that time.

The model was set with this parameter for a single model run using Scenario 1. The results show a saving of between £100m and £400m for the two smart strategies in NPV terms (it has no impact on BAU).

Table 8.6 Effect of tipping points on each investment strategy

2050 - CENTRAL CASE (SCENARIO 1)	BAU	Incremental	Top-Down
Scenario 1 - Central Case	£ 18,745,682,978	£ 12,558,619,924	£ 11,539,923,735
With Tipping Points Applied	£ 18,745,682,978	£ 12,443,377,906	£ 11,164,349,119
Benefit (£)	£ -	£ 115,242,018	£ 375,574,616
Benefit (%)	0%	1%	3%

It is noted that there would be an expectation that investment (either direct or through in-kind manpower support) would be necessary around the year tipping-point in order to yield the benefit.

The above assessment is shown primarily for illustration of the capability of the model. The true materiality of changing costs at predefined tipping points is a substantial body of work in itself and is outside of the scope of this project.

[46] Different figures have been applied across the three voltage levels following consultation with DNOs on typical levels of materiality that they would expect to see – a deployment at EHV is naturally more expensive than at LV, therefore it is appropriate that the level of financial risk would also differ.

Table 8.7 Tipping Point Results for both smart investment strategies based on the default data assumptions

	Network Name	Year Reached
1	Active Network Management - Dynamic Network Reconfiguration - HV	2017
2	Distribution Flexible AC Transmission Systems (D-FACTS) - HV	2020
3	Permanent Meshing of Networks - LV Urban	2023
4	Permanent Meshing of Networks - LV Sub-Urban	2023
5	DSR - DNO to residential	2024
6	Permanent Meshing of Networks - HV	2024
7	Fault Current Limiters_HV reactors - mid circuit	2026
8	Local smart EV charging infrastructure_Intelligent control devices	2026
9	Temporary Meshing (soft open point) - HV	2026
10	RTTR for HV Overhead Lines	2029
11	RTTR for HV/LV transformers	2029
12	D-FACTS - HV connected STATCOM	2030
13	RTTR for HV Underground Cables	2036
14	RTTR for EHV/HV transformers	2037
15	EAVC - LV PoC voltage regulators	2038
16	D-FACTS - LV connected STATCOM	2039
17	Distribution Flexible AC Transmission Systems (D-FACTS) - EHV	2039
18	Active Network Management - Dynamic Network Reconfiguration - EHV	2042
19	Temporary Meshing (soft open point) - LV	2042
20	D-FACTS - EHV connected STATCOM	2045
21	RTTR for EHV Overhead Lines	2049
22	RTTR for EHV Underground Cables	2050

8.3 Sensitivity analysis (GB Model)

Section 10.2 of Appendix A shows the significant number of variable parameters contained in this model. This section of the report draws out the sensitivities in the model to the different parameters, and describes their effect on the results. Sensitivity analysis has been carried out to explore the effects of:

- S1 – Clustering
- S2 – Applying a normal distribution has around the starting load profiles
- S3 – Different investment look-ahead periods
- S4 – Changing the costs of the top-down investment strategy
- S5 – Varying the investment trigger points
- S6 – Changing the cost curve assumptions of the smart solutions
- S7 – Increasing the solution capital costs
- S8 – Changing the ambient temperature assumptions for winter average and winter peak
- S9 – Increasing the EV charging profiles to reflect the potential impact of second generation EVs with larger batteries

Note that these sensitivities are performed using annualised investment figures to enable a like-for-like comparison to be drawn between different investment strategies.

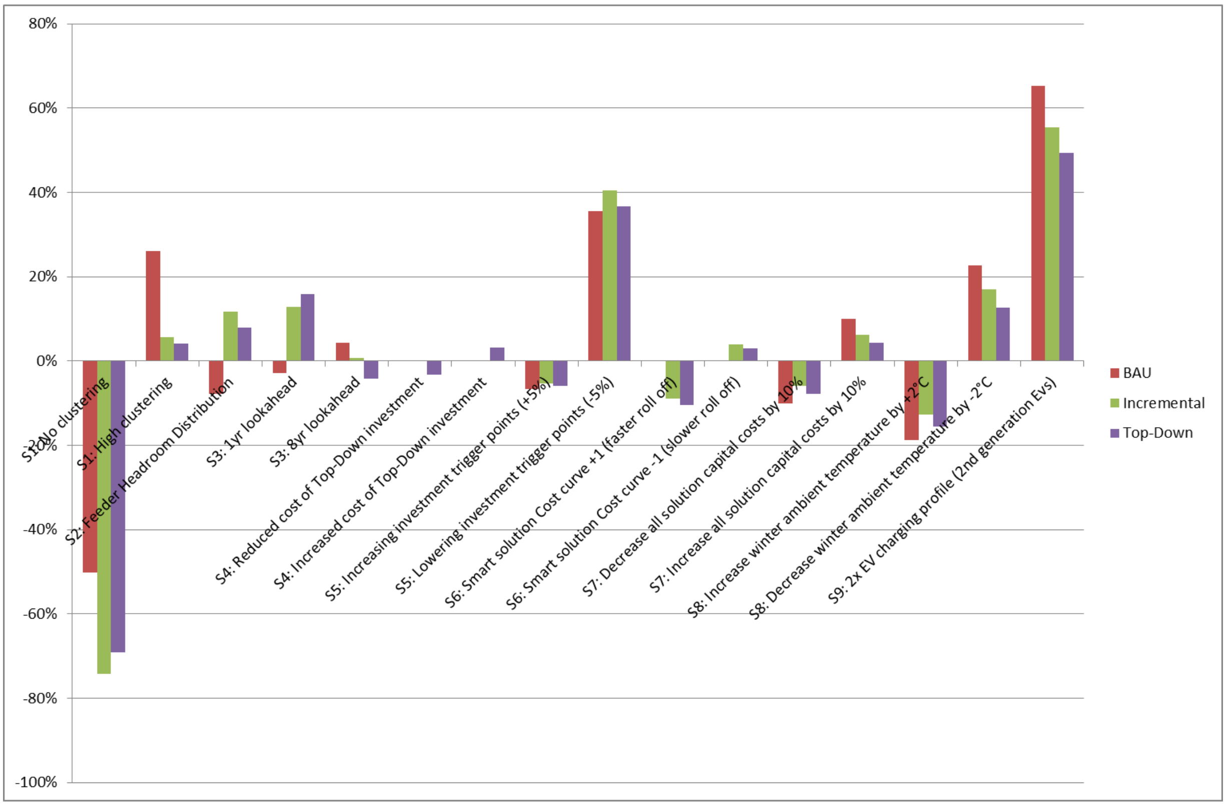

Figure 8.23 Sensitivity Analysis Overview (based on % of NPV results to 2050 for all three investment strategies, Scenario 1)

8.3.1 Sensitivity 1: Clustering

Figure 8.23 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 investment strategy. The clustering assumptions taken in the model are set out in Figure 3.12. 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.

The model has been set to apply clustering in line with the PV uptake seen across Great Britain[47] as its default for all LV connected technologies. As the PV uptake can be seen to exhibit a high degree of clustering, the sensitivity is asymmetrical, showing a significant saving on an annualised cost basis if deployment is uniform (no clustering).

The following figures demonstrate that, when considering cumulative spend across the period from 2012 to 2050, the total spend with FiT or High clustering is approximately equal for each of the investment strategies; but when the higher level of clustering is experienced, the investment is brought forward.

It can be seen that for each of the smart investment strategies, there is actually a point when the total level of investment under FiT clustering conditions exceeds that for the high clustering conditions. While this may at first seem counterintuitive, it can be explained by the fact that a greater level of earlier investment is required for the high clustering case. In turn, this leads to networks being reinforced to a greater level (as they are effectively experiencing higher load growth due to LCTs during this period). Therefore, once the later stages of the modelled period are reached, under the high clustering case, the networks have already been exposed to greater levels of reinforcement while those under the FiT case continue to require incremental investment. (It should be noted that during these later stages of the modelled period, the deployment of LCTs is such that clustering has less of an effect under the modelled scenario as LCTs are now prevalent across the entire network).

In both smart investment strategies, the cumulative investment required when no clustering is observed is considerably lower, demonstrating the powerful effect that clustering has on network demand.

In the case of the BAU investment strategy, it can be seen that, irrespective of the clustering level, the gross spend by 2050 is approximately equal. It is noticeable that the low clustering scenario shows severe blocks of investment (at 2033 and 2045). This is because the network can broadly accommodate the uptake levels of LCTs under this scenario until a critical point is reached when large numbers of networks exceed their capacity simultaneously and require wholesale reinforcement. (Within the model, this occurs because there are a number of representative feeders; clearly, in reality not every "town centre" LV feeder would require reinforcement in the same year).

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[47] Feed-in-Tariff Annual Report:
http://www.ofgem.gov.uk/Sustainability/Environment/fits/Documents1/FITs%20Annual%20Report%202010%202011.pdf

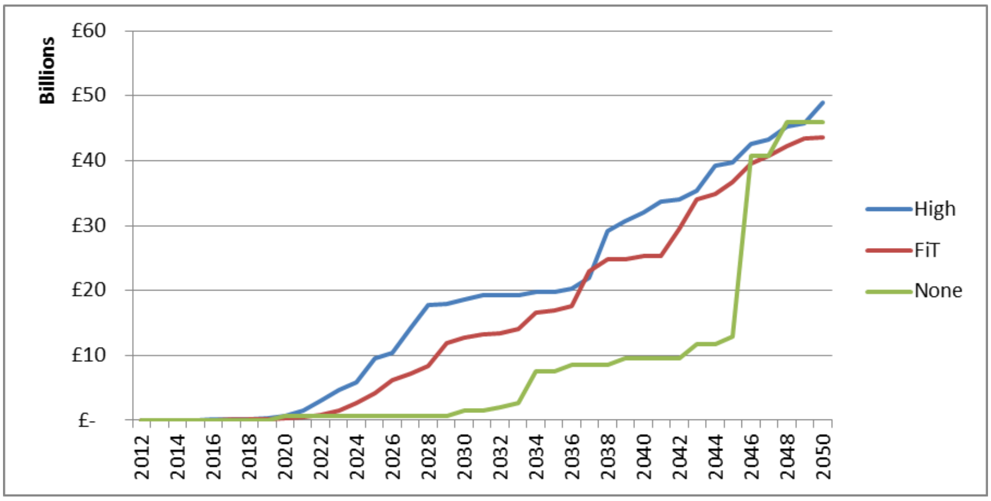


Figure 8.24 Cumulative investment under BAU strategy for three clustering levels

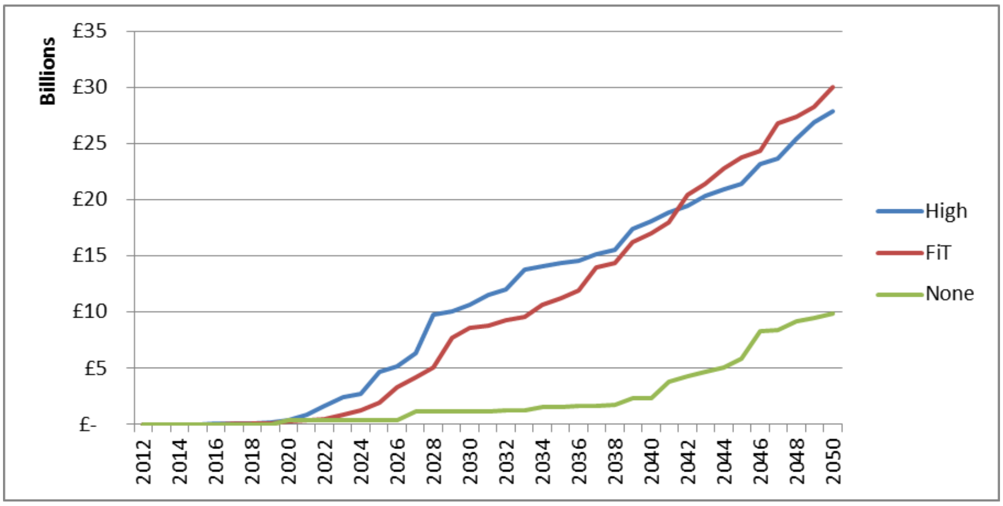


Figure 8.25 Cumulative investment under incremental strategy for three clustering levels

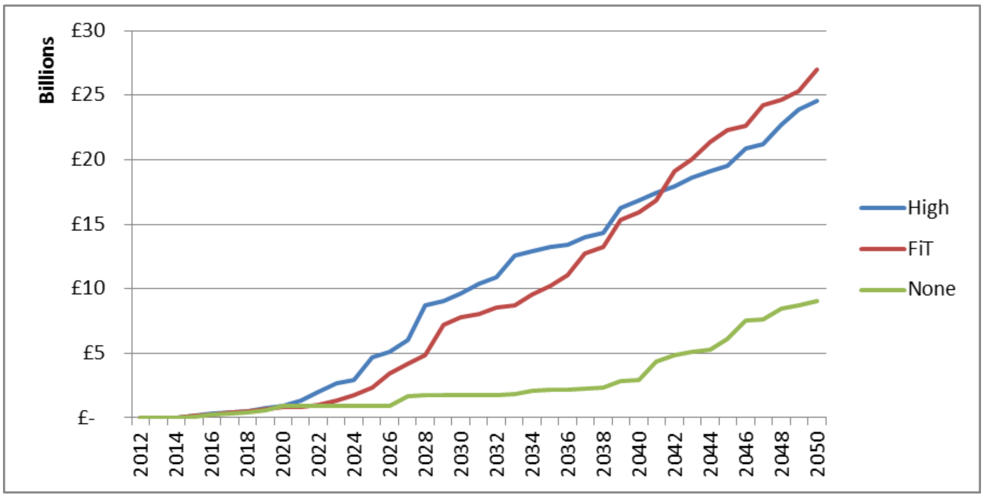


Figure 8.26 Cumulative investment under top down strategy for three clustering levels

8.3.2 Sensitivity 2: Introducing feeder headroom distribution

The feeder profiles in the model are based on typical load types and their volumes connected to a given network. This results in a single average demand for each feeder. In practice, not all feeders will be averaged; some will be more highly loaded, and others will be loaded to a lesser extent than the average. This sensitivity draws out the impact of starting with different loadings of the network, therefore different starting headroom figures (ranging from 80% of nominal to 120% of nominal).

NB. The manner in which this is modelled is to artificially create three groupings within the cluster model (this reduces the granularity of the clustering for this one test, whilst not affecting the computational complexity and run-time of the model).

As would be expected, the apportionment of a number of highly loaded feeders drives some of the GB feeders over their limits on day 1, resulting in investment in year 0 – requiring early investment in all strategies. Overall, it can be seen that the BAU strategy exhibits a cost saving, which can be attributed to the fact that the BAU solutions offer large but “lumpy” amounts of headroom. Therefore, when the load is increased to 120% of its normal rating, the investment is required, but is very similar to the investment that would be needed for the 100% load condition. Conversely, when the load is reduced to 80%, investment is not needed as quickly as would otherwise be the case. Therefore, the total amount of investment is reduced.

The smart investment strategies on the other hand show an increase in investment. This is owing to the fact that the headroom releases are generally smaller; meaning that an increase to 120% loading can cause more expensive solutions (or combinations of solutions) to be selected than would otherwise be the case. Unlike the BAU case, this is not outweighed by the deferred investment from the lower loaded portions of network and hence the investment overall is some 12% higher for incremental (8% higher for top-down).

It is important to note the results show that, particularly in the short term, clustering is shown to have a more dominant effect than the loadings of the feeders.

8.3.3 Sensitivity 3: Varying the forward look for investment

The WS3 model has been developed to satisfy the headroom requirements at a given point in time (n, where n = the number of years forward). The default in the model is set to resolve headroom constraints for a minimum of five years from the time the headroom trigger is reached.

n=1-year: This shorter look-ahead has a dominant effect on the two smart strategies. As many of the smartgrid solutions have lower headroom release, this shorter look ahead leads to repeated investment over multiple years often on the same circuits. This is clearly less efficient than the default case.

n=8-year: When a longer look-ahead period is selected, such as the eight years within this sensitivity, it can be seen (Figure 8.23) that there is zero effect on the incremental smart strategy, with a marginal reduction in investment for the top-down strategy while the BAU strategy shows a very marginal increase. It is important to note that many of the smart solutions have shorter lifetimes than the look-ahead period here. For example, all DSR solutions are only active for five years before expiring and needing to be replaced.

It may at first seem counterintuitive that the BAU strategy shows a slight increase in costs, as its solutions primarily have longer lifetimes and release larger amounts of headroom. However, this behaviour can be explained by considering the fact that the longer look-ahead period necessitates greater headroom release earlier in the modelled period. For example, a split feeder solution may give enough headroom for five years, but when considering eight years, this may need to be combined with a new transformer, or perhaps even upgraded to minor works. While this will deliver sufficient headroom to ensure no investment is required for some time, this larger investment has had to be carried out earlier than would otherwise have been the case (two solutions being applied in the current year, rather than just one for example). Hence, the total investment required shows a slight increase for this sensitivity.

8.3.4 Sensitivity 4: Varying the top-down investment costs

Assumptions have been made within the model regarding the costs of enablers to facilitate top-down investment. This sensitivity tests the effect of increasing and reducing the costs of these enablers by 50%.

As can be seen (Figure 8.23), this sensitivity is only relevant to the top-down investment strategy. As would be expected, when the enabler costs are increased, the investment required increases and vice versa. However, the scale of this additional investment is only small within the context of the model.

This clearly demonstrates that the model is not particularly sensitive to the cost of enablers, which already have an optimism bias of 66% applied to them within the model. This result gives confidence that updating these values as and when better information regarding the cost of enablers becomes available will not significantly affect the results of the model.

8.3.5 Sensitivity 5: Varying the investment trigger point on networks

This sensitivity examines the impact of adjusting the investment trigger points within the model. These points are concerned with the load as a percentage of asset rating that can be tolerated before reinforcement is required. For transformers running in parallel, this is set to 50% of rating, for example, whereas for cables it is generally set to higher figures to allow for the interconnection that exists providing potential backfeeds in the event of outages occurring.

In this sensitivity, the investment triggers have been increased and reduced by an absolute amount of 5%. This means that for the transformer case described above, the thresholds have been set to 55% and 45%; which in reality represents a change of 10% on starting levels.

The results shown in Figure 8.23 indicate that the model is sensitive to these values. When reducing the levels by 5% across the board, an increase in investment of 36 – 41% is observed. It should be noted that in reality, it would be unlikely that a DNO would change all of the trigger levels uniformly in this way. Rather, it is more likely that a small number of circuit or transformer types would be adjusted, to allow for individual DNO design policies, and hence the total increase in investment would be less than the figures shown here.

It should also be noted that a large portion of investment within this sensitivity can be attributed to meshed networks requiring investment immediately. This is a function of these networks operating, by virtue of their design, closer to their ratings than radial networks.

By contrast, when the investment trigger points are increased, the level of reduction in investment overall is much smaller (around 5 – 7%). The reason for this is that increasing the trigger levels pushes some investment back in the modelled period. However, there is not the same pronounced effect as observed when reducing the trigger points as there is no direct opposite effect to that of necessitating year 0 investment.

8.3.6 Sensitivity 6: Changing the cost curves of all smart solutions

Within the model, each solution is ascribed a cost curve, which defines how its cost varies over the modelled period. This sensitivity looks at altering the cost curve for each solution, firstly by increasing the cost curve (which produces a faster roll-off of future costs) and secondly by reducing the cost curve number (to give a slower roll-off of future costs). This sensitivity has only been applied to smart solutions; conventional solutions have been held constant at cost curve 1 (slowly increasing over time).

When applying a faster roll-off, it can be seen from Figure 8.23 that a reduction of approximately 6 - 8% is found for both incremental and top-down investment strategies. This is to be expected as costs of the solutions are decreasing more rapidly, thus resulting in lower overall expenditure.

When the cost curve number is reduced (thereby ensuring a slower roll-off), it can be observed that the impact is only marginal. The top-down costs increase very slightly, and this is linked to the fact that a number of enablers required to facilitate top-down investment (such as those associated with obtaining data from the DCC) have a flat cost curve (cost curve 2). These represent a significant amount of investment within the top-down strategy and when the cost curve is adjusted to 'cost curve 1' this results in the cost of these enablers increasing over time, and hence driving the overall cost of the top-down investment strategy up.

The cost associated with the incremental strategy, on the other hand, appears as a very slight reduction. This merely represents the level of error to be found within the model as this adjustment to cost curves would not be expected to deliver a net benefit and this result can be treated as having no effect on investment levels.

8.3.7 Sensitivity 7: Varying all solution capital costs

All capital costs in the model have been determined based on extensive analysis of existing costs (making use of Ofgem benchmarks for conventional solution costs, for example), and by taking data from available sources regarding on-going LCN Fund or IFI projects. This sensitivity looks at increasing and reducing the capital costs of all solutions (both smart and conventional) by 10%.

It can be seen from Figure 8.23 that this sensitivity produces the results that would be expected. When the capital costs of solutions are increased by 10%, the level of investment required similarly increases for all strategies by approximately 10%. Conversely, when the costs of solutions are reduced by 10%, the necessary investment reduces by 10% across all investment strategies.

8.3.8 Sensitivity 8: Varying the winter ambient temperature

It can be seen that when the ambient temperature during the winter is reduced by 2°C during winter, the investment across all strategies is increased as a result of demand increasing for this condition (particularly electric heating and heat pump demand).

Conversely, if the temperature is increased by 2°C, then the required investment is reduced. In the case of the BAU investment strategy, the amount by which investment requirements change is symmetric for these two cases, while for the smart strategies, a smaller benefit is realised when considering higher temperatures. This is explained by the fact that a more significant amount of expensive reinforcement with “lumpy” headroom release is avoided in the BAU case. Under the smart strategies, however, the applicable solutions (such as DSR) have lower costs and can release the necessary headroom at a lower cost.

This leads to a smaller amount of expenditure being saved by the temperature increase than is observed under the BAU strategy.

8.3.9 Sensitivity 9: Increasing the EV charging profiles to reflect the potential impact of second generation EVs

The model is sensitive to the magnitude of the EV charging profile, and the effect of doubling this is significant. This is to be expected, as under the default assumptions the diversified EV charging profile (based on TSB trial data) suggests over 1kW of load per residential property – a doubling of the current ADMD (After Diversity Maximum Demand) of a household and the basis on which most LV networks are designed. Doubling this to emulate possible increases in EV charging demand, further exacerbates the situation, driving between 50% and 65% increases in investment on our default case.

The model has been created using best available data, but it is clear that the EV charging could pose a significant challenge to electricity networks. It is therefore recommended that further work be done in this area as different types of electric vehicles (and their variants) come onto the market, and are adopted by GB citizens.

8.3.10 'What if' Analysis...

The following analysis has been performed to assess the sensitivity within the model for certain solutions being unavailable, or changes to solution costs.

8.3.10.1 ..Some commonly selected solutions do not materialise

- The dynamic merit order is currently choosing what it believes to be the optimum mix of solutions
- This results in certain solutions being picked repeatedly (such as permanent meshing and D-FACTS)
- The model was run with each of these solutions removed
- Because there are a number of smart solutions available at similar cost, the model picks those without significant impact on headline cost

8.3.10.2 ..EV DSR is not available

- We have disabled any DSR associated with EV load at a national level and have also disabled the EV charging unit solution
- This has very little impact in terms of overall investment levels for each of the smart investment strategies (a maximum of £200m across the entire modelled period)
- But it does change the blend of solutions deployed:
  - For the two smart investment strategies the model calls upon £2.67bn of permanent meshing and £0.75bn of split feeders
  - For the Conventional approach the model selects Split Feeders
- It is of note that the model does not factor in the true inconvenience costs to GB society in deploying solutions, therefore the inconvenience of installing £0.75bn of split feeders across GB is not captured in the results

8.3.10.3 ..Electrical Energy Storage costs are substantially reduced

- Several of the early LCN Fund projects have focussed around the use of electrical energy storage as a component part of the smartgrid
- Yet this is a solution that is not being selected by the model for the default case in any of the scenarios or investment strategies
- This is principally associated with the relatively high starting position for capital cost (e.g. £16m for EHV storage), which, when compounded with a 66% optimism bias (takes the EHV unit to c£26m), is making this solution extremely expensive compared to other alternatives
- The model has been run with the costs of storage reduced to 10% of the current costs
- The outputs show significant volumes of storage units applied, particularly at LV and HV voltage levels

8.3.10.4 .. the LCT scenario input data is removed

This sensitivity has been run to assess the impact of zero LCTs applied across the 38 years of the model (i.e. all values set to 2012).

Table 8.8 Sensitivity analysis – removing scenario input data

No LCT	Discounted Totex
To 2050	£372m (2.0% of BAU equiv)
To 2030	£-
To 2022	£-

No LCT, no wind	Discounted Totex
To 2050	£492m (2.6% of BAU equiv)
To 2030	£492m (6.4% of BAU equiv)
To 2022	£-

The outputs show a very small investment, driven by the modest assumptions of underlying load growth, and in this case, only for one type of network – meshed HV networks, where operation close to headroom limits is typical.

Whilst a baseline of load is assumed, the underlying projections for energy efficiency more than cancel this out. It is noted that the model has no concept of load churn (i.e. load moving from one type of area or network to another, it is therefore unable to build an accurate picture of load related investment needs.

Investment is slightly higher for instances where wind and LCT have been omitted from the model. This result is due to the fact that generation nets off local load, without generation (albeit in relatively modest levels) applied across the networks, the load has to all be supplied from the infeeding substations.

This demonstrates that the model is only focusing on investment driven by the deployment of low carbon technologies (Heat Pumps, Electric Vehicles, PV generation, wind generation, biomass).

8.4 Comparison of GB network model against Work Stream 2 results

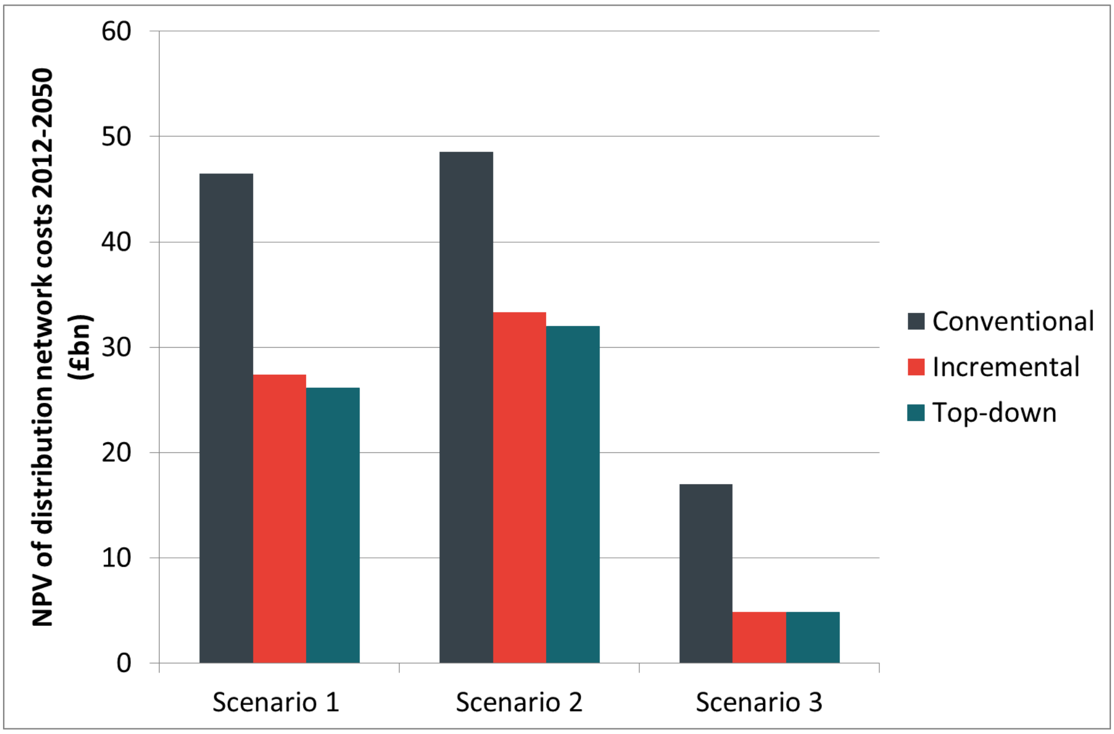


Figure 8.27 Gross NPV of investment as taken from WS2 model

There is a notable difference between the results of the WS3 model and the WS2 outputs. This is to be expected. The WS2 project hinged around the creation of an evaluation framework for smart grids investment. It was populated with a sample of data (with stated assumptions), but always caveated by its authors and Ofgem as being a starting point as a first-of-its-kind techno-economic model.

In contrast, this project under WS3 has focused on the datasets used, building on and expanding the methodology used in the WS2 model only where necessary to underpin the improved data. In contrast to the full Value Chain approach given in WS2, this WS3 project has had a more specific focus on Distribution Networks. While the WS2 work established a framework for the assessment of the costs and benefits of smart grids, the WS3 work has increased the robustness of the data inputs, and the granularity of the network analysis.

The differences between the two models are described in Figure 8.28 below, for the purposes of comparison; this assessment has focussed on comparing the Conventional (Business-As-Usual) costs of Scenario 1.

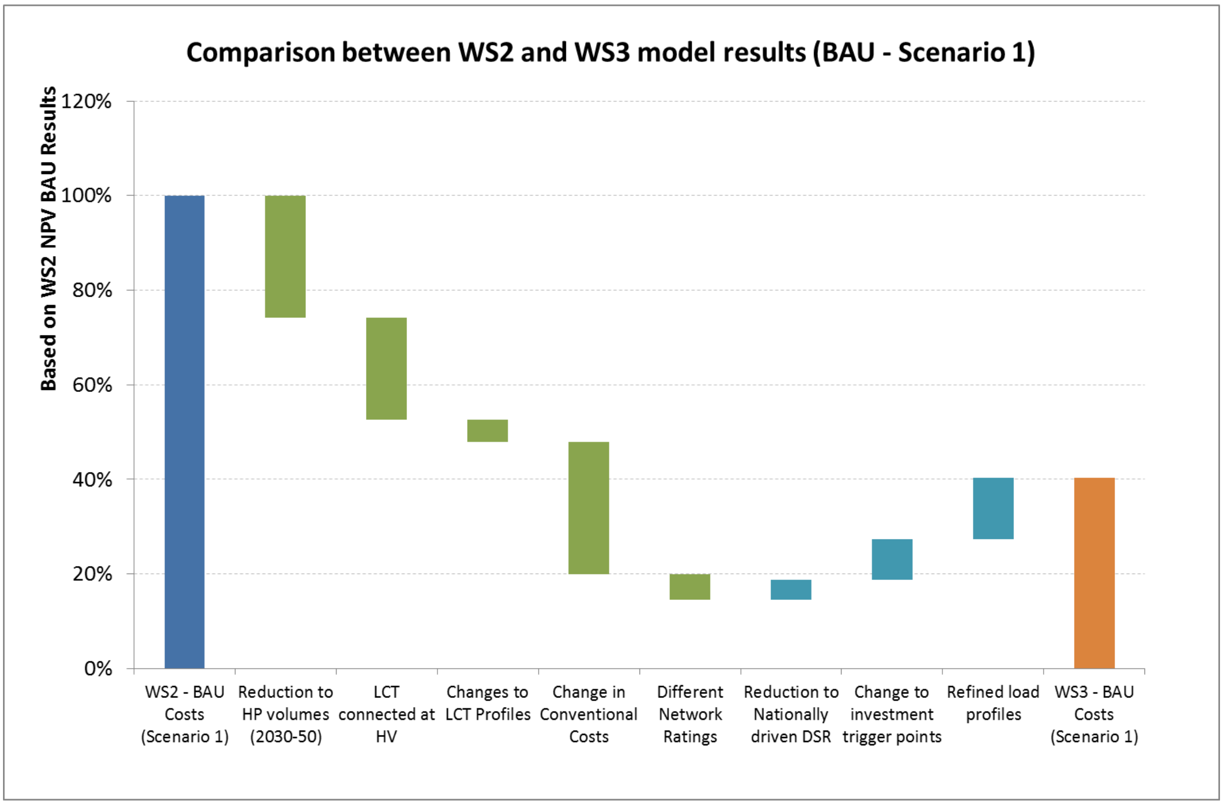


Figure 8.28 Illustrative waterfall diagram drawing out the changes between the WS2 and WS3 model outputs

There are multiple changes that have been made between the WS2 and WS3 model – as described in Appendix A, there are now over 40 different variables applied in the model, each of which has the potential to affect the model results. The factors outlines in Figure 8.28 above have indicative cost amounts associated with them. The reason that these are indicative rather than absolute is that these various factors interact with each other in fairly complex ways, making it difficult to easily apportion “£x billion” to one particular factor. The fact that the various changes are not merely additive (some can be multiplicative when combined with other factors, for example) makes such a representation difficult, but the following notes help to draw out some of the key points.

The major factors driving differences are:

- **Reduction to HP volumes (2030 – 2050)**: The WS1 scenarios for heat pumps only contain data to 2030. It is therefore necessary to make an assumption regarding heat pump uptake in the period 2030 – 2050. In the WS2 model this was achieved by examining the growth between 2025 – 2030 and assuming a linear growth over the next twenty years based on the rate of growth observed over that five year period. In WS3 a different approach has been taken whereby an annual growth rate of 4% has been used for scenarios 0,1 and 2 (with a rate of 7% used for scenario 3). This is based on extensive analysis of the data and is believed to offer a more realistic projection over the period 2030 – 2050. However, as a result, by 2050 there are approximately 16 million fewer heat pumps connected to the network in the WS3 model than in WS2. Clearly this results in a reduction in the amount of investment required to accommodate these heat pumps.
- **LCT connected at HV**: In the WS2 model, all new build residential homes were applied directly to the LV network. This was changed for the WS3 model, with new build connected instead to the HV network – reflecting the most likely occurrence as new housing estates

(particularly those supporting low carbon builds and living). It is noted that by 2050 around ⅓ of all low carbon technologies are associated with new build properties. Connection at HV avoids headroom breaches at LV, which consequently has been shown to reduce investment by a significant amount.

- **Changes in LCT profiles**: Analysis undertaken for this project has further validated the profiles to use for each of the low carbon technologies in the WS3 model. This has resulted in a marginal reduction in the profiles of, in particular, those associated with Commercial Heat Pumps and PV connected to residential properties. This change results in a modest reduction on the model outputs.
- **Reduced cost of Conventional Solutions**: The dominant change here has been with the introduction of 'minor works' solution (at all voltage levels) as a bridge between 'new transformer' and 'major works'. In many instances, where new splitting feeders or transformers are insufficient to resolve headroom constraints, major works, with an associated high cost was triggered, this is now being replaced with the minor works solution (see Figure 8.19). The introduction of this single new solution has been shown to reduce investment by a large amount.
- **Different ratings of networks**: Analysis of the Long Term Development Statement (LTDS) data and discussions with the DNO community have improved the starting ratings of the circuits, to those used in WS3. This is particularly the case for EHV and HV circuits, where good data exists in volume. It is noted that data for LV networks remain sparse. This change has resulted in a modest reduction on the model outputs.
- **A reduction to the nationally driven DSR**: The amount of DSR applied at National level (e.g. to reduce the investment in large generation plant) is largely affected by the cost associated with its use (i.e. 'disruption' payments made to customers to delay switching on their washing machines or charging their Electric Vehicles). In the WS2 model, a figure of 2p/kWh was assigned to this. Sensitivity runs have taken place applying both 2p/kWh and £2/kWh for this report. As expected, as the cost increases, DSR has less of an impact. The WS3 model default is set to 20p/kWh in line with a 100% differential from the standard electricity tariff. At this rate, less DSR is being enacted at a National level. As the national DSR tends to coincide with DNO peaks it helps reduce DNO investment. Increasing this value to 20p/kWh is raising the DNO investment costs as shown.
- **Changes to investment trigger points**: In WS2 no reinforcement of circuits or transformers was carried out until all headroom had been fully utilised (i.e. when the circuit reached 100% of its rating). Within the WS3 model, a more sophisticated approach is taken whereby reinforcement trigger levels are set. These vary depending on the type of circuit and substation. In the case of substations with transformers that are expected to run in parallel, the reinforcement trigger is 50% (meaning that under n-1 conditions, one transformer can take 100% of the associated load). Circuits are treated differently and have had their reinforcement triggers set depending on the network topology (meshed or radial) and the expected amount of interconnection (and therefore alternative feeds that could be used under n-1 conditions) depending on whether the circuit is in, for example, an urban or rural setting. The result of this is that investment is being triggered earlier in the WS3 model, leading to an increase in investment costs.
- **Refined load profiles**: In WS2, the starting load profiles for LV feeders were based on engineering judgement and a number of assumptions. This has been revisited and significantly expanded upon within this project. A granular, bottom-up analysis of MPANs

has taken place across several DNO licence areas to determine the number, and types, of customers that are found on the same LV feeders. This, in combination with the work carried out to determine the point loads associated with different customers, has allowed accurate representations of loads on different types of LV feeders to be quantified. Certain loads have been subject to diversity factors to account for the fact that only small numbers of customers are present along a feeder and fully diversified profiles are therefore not applicable. This entire analysis has resulted in the construction of robust load profiles, which show an increase over the starting load profiles used within WS2 and hence produce increased investment needs.

8.5 Licence model sample results

A synthetic licence specific set of data has been created to provide an indication of the types of results that would be brought out from the DNO model. It is noted that the data used here has been fabricated for this purpose, and that any resemblance to an existing network is purely coincidental.

NB. For the purposes of this comparison, only the results for the incremental smart strategy have been drawn out.

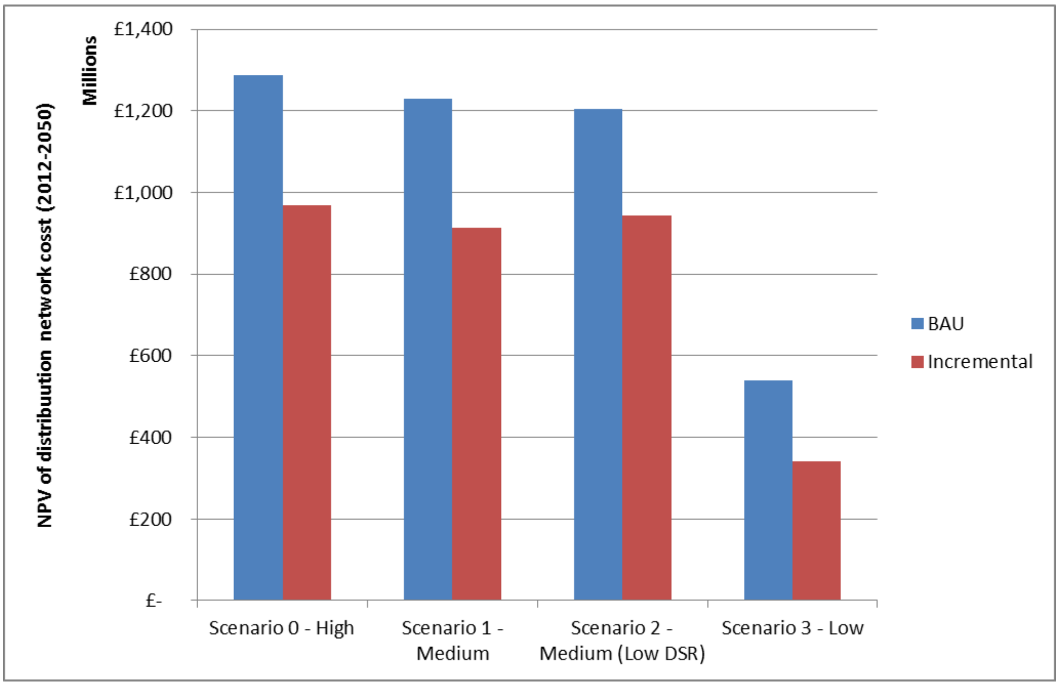


Figure 8.29 NPV of annualised investment for the synthetic DNO licence model, 2012-50 (all scenarios, BAU and Incremental Smart investment strategies)

As with the GB output, the regional model shows a benefit for the incremental smart over the BAU investment strategy.

Points to note:

- The results are higher than a 1/14th of the GB picture, as the data has not been inputted on a simple scaled basis, but instead developed to look like a 'pseudo-real' network, which includes:
    - A high number of Central Business District (CBD) and town centre feeders to represent a major city
    - A high number of meshed networks, in urban areas
    - Two new feeder types: 1x DG heavy and 1x 132kV to 11kV to demonstrate how the model can be flexed to suit network configurations that are not part of the 'standard' set
- The model is showing investment being required in year 0. In this instance, that would suggest that either the apportionment of circuits is incorrect for the total load in the synthetic licence area, or that key feeder parameters such as circuit ratings or investment trigger points are different in the GB model than for this DNO.

- Once the year 0 investment has occurred, there is no investment required until the middle part of RIIO-ED1, as the volumes of LCTs start to rise, consistent with the results of the GB model.
- The regional model is similarly sensitive to the factors drawn out for the GB model in Section 8.3. Clustering in particular, will have an impact on the results at a local level.

As with the results of the GB network model (Section 8.2) two of the more interesting scenarios are shown below, with results and differences drawn out between them. Note the year 0 investment off-sets the investment profile by c£150m (Incremental) and £315m (BAU) in both Figure 8.30 and Figure 8.32.

Scenario 1 – Mid Case

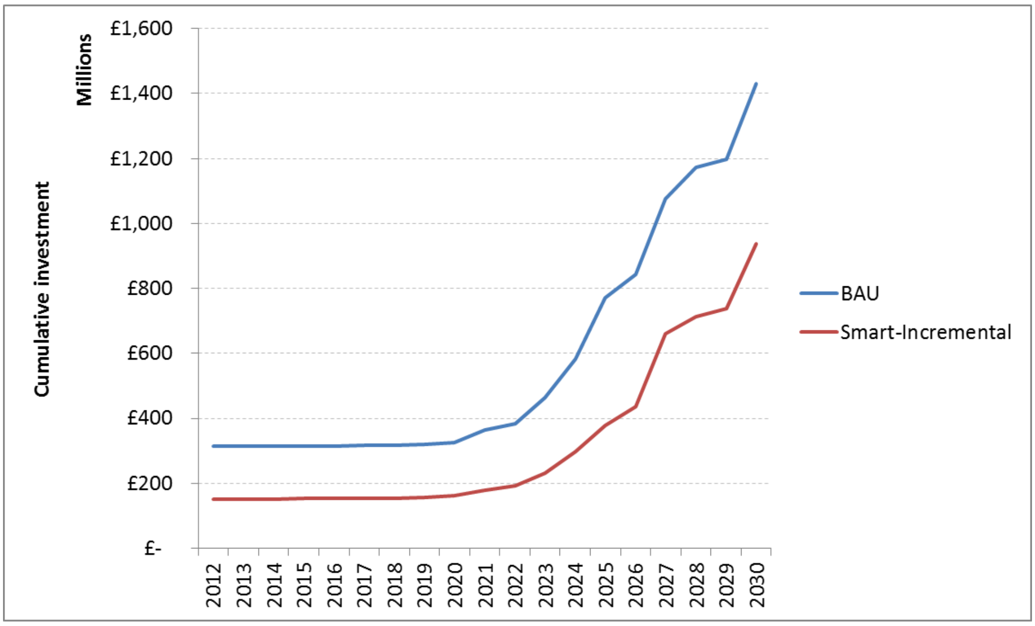


Figure 8.30 Summary of gross cumulative investment for Scenario 1 for the synthetic DNO licence model, 2012-30

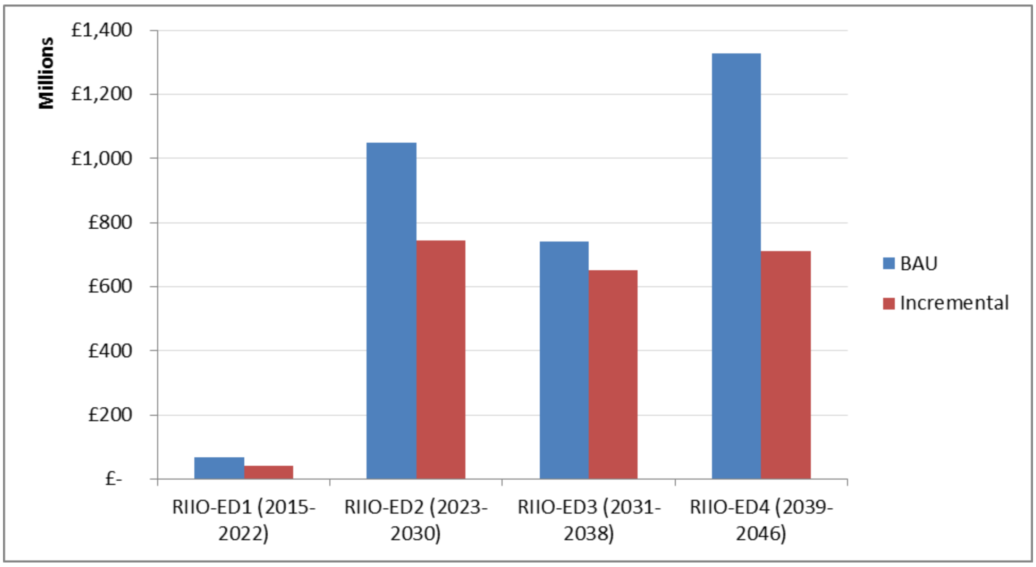


Figure 8.31 Breakdown of DNO licence totex investment for Scenario 1 in 8-year blocks, as aligned to GB electricity distribution price control periods

Low Case – Scenario 3

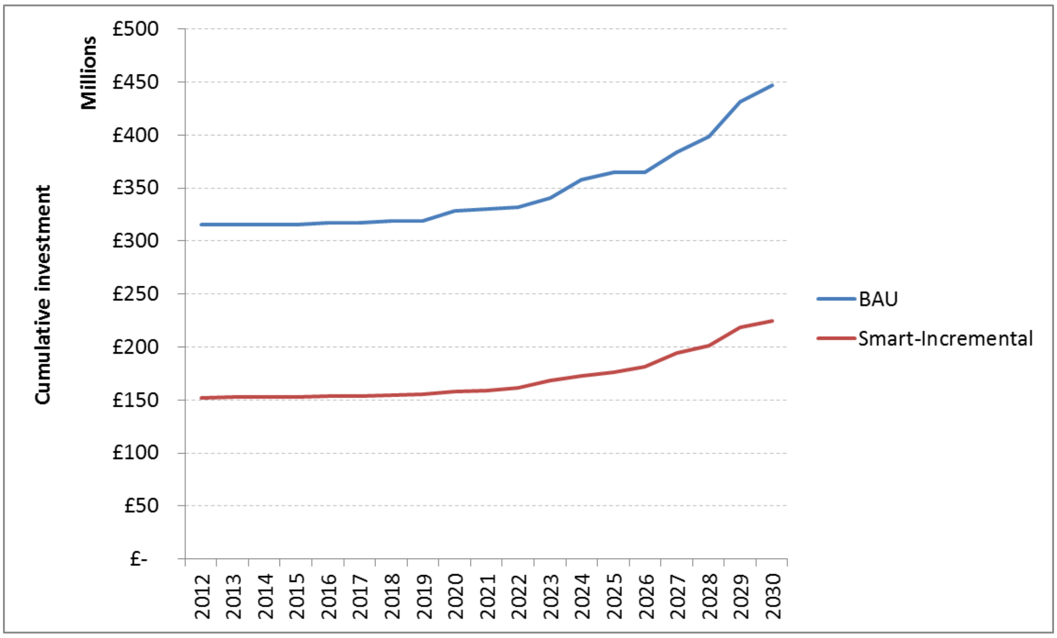


Figure 8.32 Summary of gross cumulative investment for Scenario 3 for the synthetic DNO licence model, 2012-30

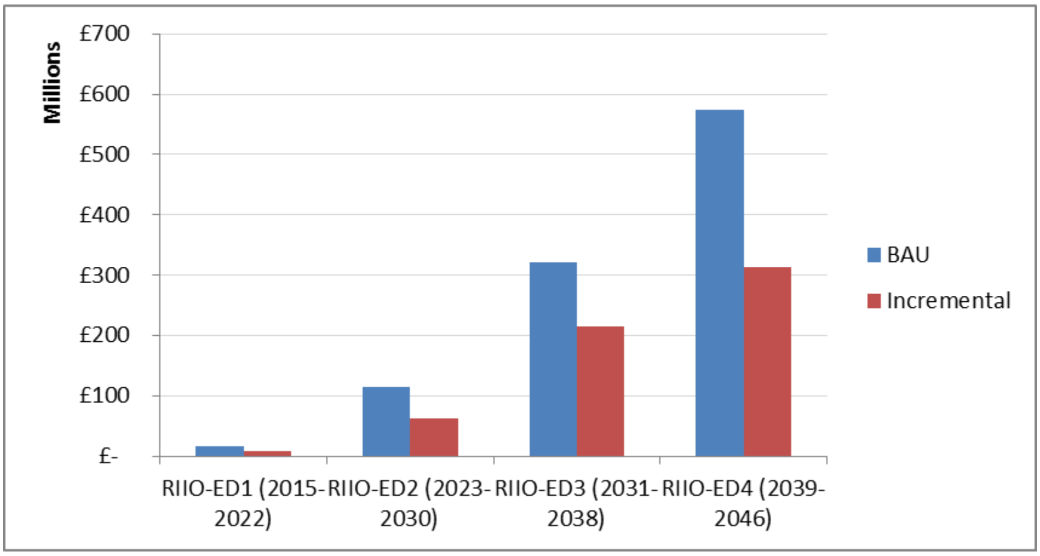


Figure 8.33 Breakdown of DNO licence totex investment for Scenario 3 in 8-year blocks, as aligned to GB electricity distribution price control periods

Comparing the two results on the same graph show the potential scale of investment in the RIIO-ED1 and RIIO-ED2 period, depending upon the investment strategy adopted.

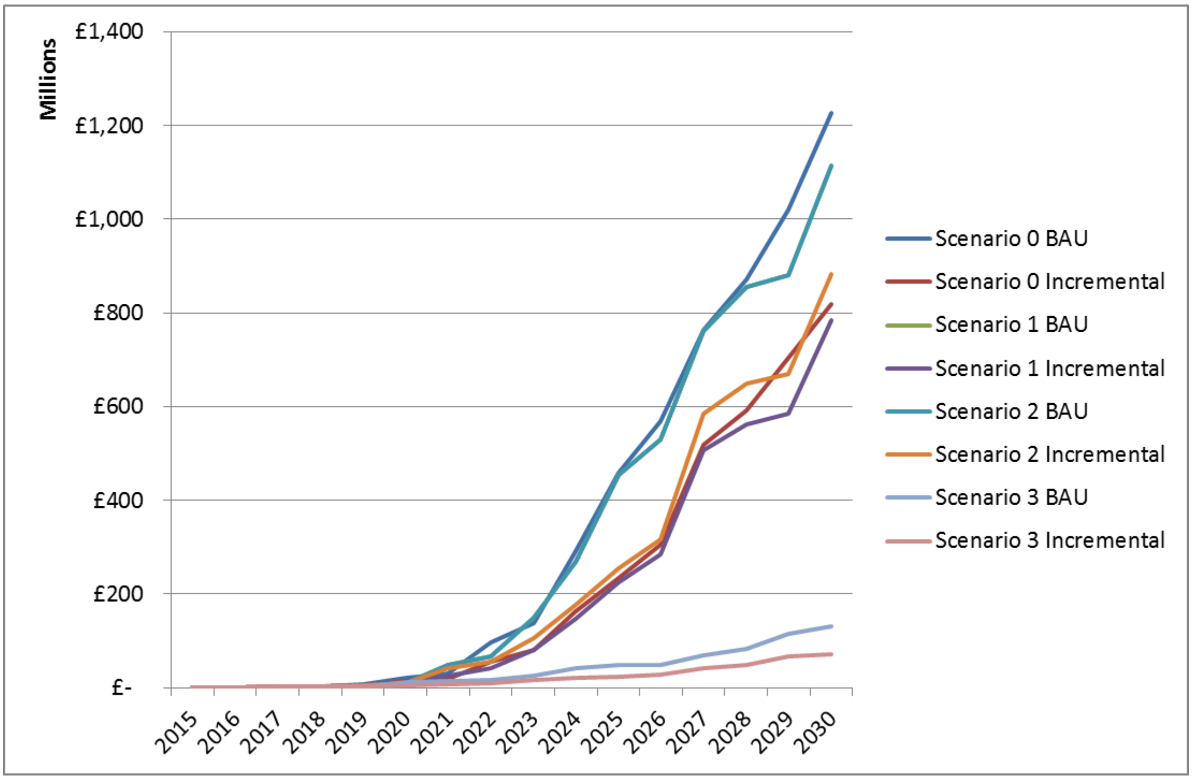


Figure 8.34 Comparison showing the potential spread of gross cumulative investment for all scenarios for the synthetic DNO licence model, 2012-30 (normalised to remove year 0 investment) for BAU and incremental smart investment strategies only

8.6 Licence model sensitivity

All sensitivities as run for the GB model hold true for the DNO licence specific model.

In recognition that robust data on LV networks is limited at present, an additional sensitivity has been run to show the effect apportioning different amounts of LV feeders to HV feeders will have on the output. A number of feeder combinations were switched to understand the sensitivity; the effects were proven to be minimal.

When one change was made (i.e. the amount of circuits attributed to one LV feeder type was increased by 5% and another was reduced by 5%) the effect was found to change the annualised investment costs by 0.4% for BAU and 0.3% for incremental investment strategies respectively.

When four changes were made (such that the prevalence of four types of LV feeders was increased by 5% each and the number of four other types of feeders found in the network as reduced by 5% each) an overall change in annualised investment of 5% for BAU and 4% for incremental strategies was observed.

8.7 Linkage to observations made in the WS3 Phase 1 report

The methodology used for the analysis identifies the implications for networks of the national low carbon scenarios and develops responses that include a range of smart grid techniques. This wide range of innovative options has been consolidated into a smaller number of 'Solution Sets', which summarise the building blocks that can be used to augment network investment.

The WS3 Phase 1 report concluded that future network architectures are likely to develop in stages with a first phase, termed Smart Grid 1.0, using largely established innovation techniques in an increasing number of projects. In the longer term a Smart Grid 2.0 stage will incorporate more ambitious innovation and the scale of deployment will become more extensive, progressively and systematically populating the network in response to local needs.

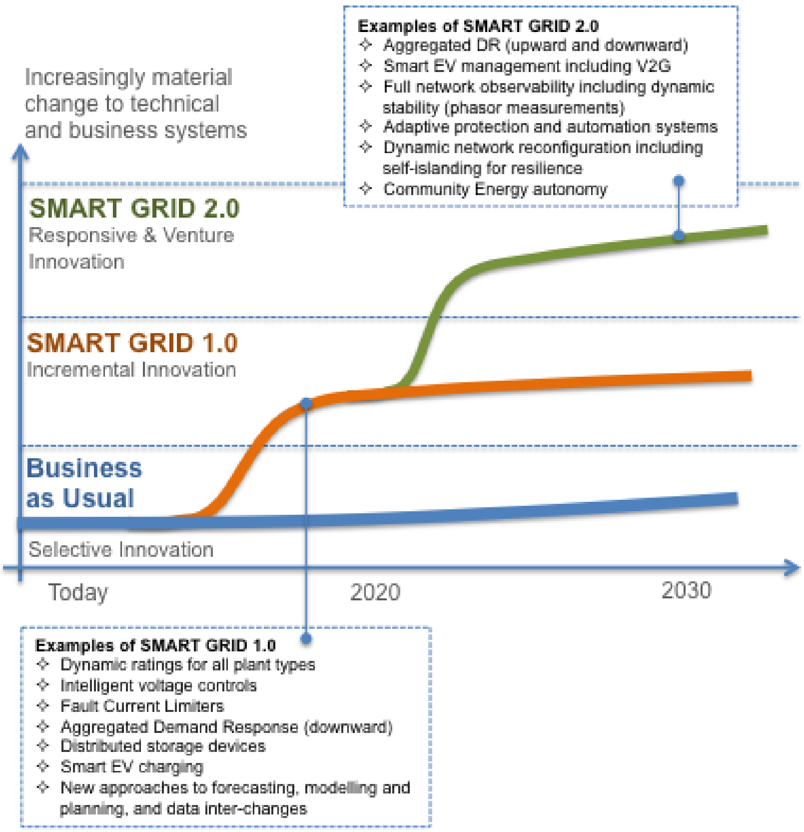


Figure 8.35 The two 'versions' of smart grid evolution

The twelve solution sets are provided in Appendix D. In order to translate these into a modelling framework, it has been necessary to define some of the specific technologies or commercial solutions that sit within the solutions sets.

The representative solutions against each of each of the twelve solution sets are shown below.

Table 8.9 Overview of the solutions inputted in the model as they relate to the WS3 Phase 1 solution sets

	v1.0	v2.0
Solution Set	**Solution**	**Solution**
Smart D-Networks 1	Active Network Management - Dynamic Network Reconfiguration	
	Temporary Meshing (soft open point)	
	Distribution Flexible AC Transmission Systems (D-FACTS)	
	Electrical Energy Storage	
	Switched Capacitors	
Smart D-Networks 2	fault current limiters	DSR
	Electrical Energy Storage	Electrical Energy Storage
	Enhanced Automatic voltage Control (EAVC)	
	Generator Constraint Management, GSR (Generator Side Response)	
	Generator Providing Network Support, e.g. PV Mode	
Smart D-Networks 3	RTTR	Distribution Flexible AC Transmission Systems (D-FACTS)
	New Types Of Circuit Infrastructure	
Smart D-Networks 4	Active Network Management - Dynamic Network Reconfiguration	Embedded DC Networks
	Permanent Meshing of Networks	Active Network Management - Dynamic Network Reconfiguration
		Electrical Energy Storage
Smart T-Networks	RTTR	DSR
	DSR	
Smart EV charging	Local smart EV charging infrastructure	Electrical Energy Storage
		Local smart EV charging infrastructure
Smart storage	Electrical Energy Storage	Electrical Energy Storage
		RTTR
Smart Community Energy		DSR
Smart buildings and connected communities	DSR	
	Electrical Energy Storage	
Smart Ancilliary services (local and national)		
Inter-sector energy transfer		DSR
		Electrical Energy Storage
Conventional	Split feeder	
	New split feeder	
	New transformer	
	Minor works	
	Major works	

As described in Section 5.6 when a network trigger threshold is breached, solutions are selected based on the merit order they are assigned, based upon the following:

- **Totex** – the sum of capital expenditure plus the NPV of annual operating expenditure over the life of the asset.
- **Disruption** – the value placed on avoiding the disruption required to install and operate a solution.
- **Cross Network Benefits** – the ability for a solution to deliver benefits to an adjacent network (e.g. a HV solution that also gives a benefit to LV network or EHV network).
- **Flexibility** – the ability to relocate/reuse a solution when it has fulfilled its primary purpose. This takes into account the asset life expectancy and any ancillary benefits offered by the solution.
- **Life expectancy** – this considers the residual life of the asset at point n in time (where n is set to be the number of years forward in time for the model to resolve a problem, following a breach of headroom)

This prioritises the way in which solutions, both smart and conventional, are applied to networks to solve headroom/legroom issues. Selection of certain solutions is therefore subject to the data entered for each of the parameters above. Whilst the model uses professional judgement, based on best available data, it should not be regarded as definitive.

The figures presented here provide an illustrative of the split between solution-sets. However it should be noted that solutions which appear in more than one solution-set have been apportioned evenly across those sets.

Table 8.10 Modelled Results as split by the 12 solutions sets from the WS3 Ph1 report (Gross cumulative investment for Incremental Smart Strategy, 2012-2030)

	v1.0			v2.0		
Solution Set	**Solution**	**Financial materiality**	**Sum of investment**	**Solution**	**Financial materiality**	**Sum of investment**
Smart D-Networks 1	Active Network Management - Dynamic Network Reconfiguration	£ 92,430,875				
	Temporary Meshing (soft open point)	£ 45,783,132				
	Distribution Flexible AC Transmission Systems (D-FACTS)	£ 250,774,691				
	Electrical Energy Storage	£ -				
	Switched Capacitors	£ -	**£ 388,988,699**			
Smart D-Networks 2	fault current limiters	£ 67,913,508		DSR	£ 38,829,161	
	Electrical Energy Storage	£ -		Electrical Energy Storage	£ -	
	Enhanced Automatic voltage Control (EAVC)	£ 1,610,831				
	Generator Constraint Management, GSR (Generator Side Response)	£ -				
	Generator Providing Network Support, e.g. PV Mode	£ -	**£ 69,524,339**			**£ 38,829,161**
Smart D-Networks 3	RTTR	£ 54,038,294		Distribution Flexible AC Transmission Systems (D	£ 250,774,691	
	New Types Of Circuit Infrastructur	£ -	**£ 54,038,294**			**£ 250,774,691**
Smart D-Networks 4	Active Network Management - Dyr	£ 92,430,875		Embedded DC Networks	£ -	
	Permanent Meshing of Networks	£ 2,656,438,911		Active Network Management - Dynamic Network	£ 92,430,875	
			£ 2,748,869,786	Electrical Energy Storage	£ -	**£ 92,430,875**
Smart T-Networks	RTTR	£ 54,038,294		DSR	£ 38,829,161	
	DSR	£ 38,829,161	**£ 92,867,456**			**£ 38,829,161**
Smart EV charging	Local smart EV charging infrastruc	£ 79,374,295		Electrical Energy Storage	£ -	
			£ 79,374,295	Local smart EV charging infrastructure	£ 79,374,295	**£ 79,374,295**
Smart storage	Electrical Energy Storage	£ -		Electrical Energy Storage	£ -	
			£ -	RTTR	£ 54,038,294	**£ 54,038,294**
Smart Community Energy				DSR	£ 38,829,161	**£ 38,829,161**
Smart buildings and connected communities	DSR	**£ 38,829,161**				
	Electrical Energy Storage	£ -	**£ 38,829,161**			
Smart Ancilliary services (local and national)						
Inter-sector energy transfer				DSR	£ 38,829,161	
				Electrical Energy Storage	£ -	**£38,829,161.44**
Conventional	Split feeder	£ 842,500,545				
	New split feeder	£ -				
	New transformer	£ 1,680,219,348	**£ 3,114,281,809**			
	Minor works	£ 591,561,916				
	Major works	£ -				

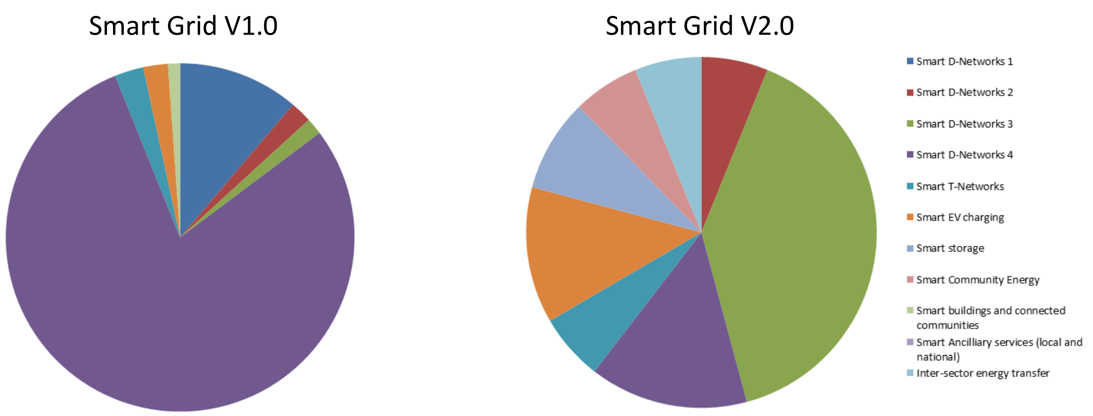


Figure 8.36 Summary of investment by smart solution set (incremental)

Table 8.11 Modelled Results as split by the 12 solutions sets from the WS3 Ph1 report (Gross cumulative investment for Top-Down Smart Strategy, 2012-2030)

	v1.0			v2.0		
Solution Set	**Solution**	**Financial materiality**	**Sum of investment**	**Solution**	**Financial materiality**	**Sum of investment**
Smart D-Networks 1	Active Network Management - Dynamic Network Reconfiguration	£ 92,430,875				
	Temporary Meshing (soft open point)	£ 45,783,132				
	Distribution Flexible AC Transmission Systems (D-FACTS)	£ 279,504,335				
	Electrical Energy Storage	£ -				
	Switched Capacitors	£ -	**£ 417,718,342**			
Smart D-Networks 2	fault current limiters	£ 67,913,508		DSR	£ 38,829,161	
	Electrical Energy Storage	£ -		Electrical Energy Storage	£ -	
	Enhanced Automatic voltage Control (EAVC)	£ 1,610,831				
	Generator Constraint Management, GSR (Generator Side Response)	£ -				
	Generator Providing Network Support, e.g. PV Mode	£ -	**£ 69,524,339**			**£ 38,829,161**
Smart D-Networks 3	RTTR	£ 150,565,285		Distribution Flexible AC Transmission Systems (D	£ 279,504,335	
	New Types Of Circuit Infrastructur	£ -	**£ 150,565,285**			**£ 279,504,335**
Smart D-Networks 4	Active Network Management - Dyr	£ 92,430,875		Embedded DC Networks	£ -	
	Permanent Meshing of Networks	£ 2,656,438,911		Active Network Management - Dynamic Network	£ 92,430,875	
			£ 2,748,869,786	Electrical Energy Storage	£ -	**£ 92,430,875**
Smart T-Networks	RTTR	£ 150,565,285		DSR	£ 38,829,161	
	DSR	£ 38,829,161	**£ 189,394,447**			**£ 38,829,161**
Smart EV charging	Local smart EV charging infrastruc	£ 79,374,295		Electrical Energy Storage	£ -	
			£ 79,374,295	Local smart EV charging infrastructure	£ 79,374,295	**£ 79,374,295**
Smart storage	Electrical Energy Storage	£ -		Electrical Energy Storage	£ -	
			£ -	RTTR	£ 150,565,285	**£ 150,565,285**
Smart Community Energy				DSR	£ 38,829,161	**£ 38,829,161**
Smart buildings and connected communities	DSR	**£ 38,829,161**				
	Electrical Energy Storage	£ -	**£ 38,829,161**			
Smart Ancilliary services (local and national)						
Inter-sector energy transfer				DSR	£ 38,829,161	
				Electrical Energy Storage	£ -	**£38,829,161.44**
Conventional	Split feeder	£ 927,742,833				
	New split feeder	£ -				
	New transformer	£ 1,680,219,348	**£ 3,064,218,878**			
	Minor works	£ 456,256,698				
	Major works	£ -				

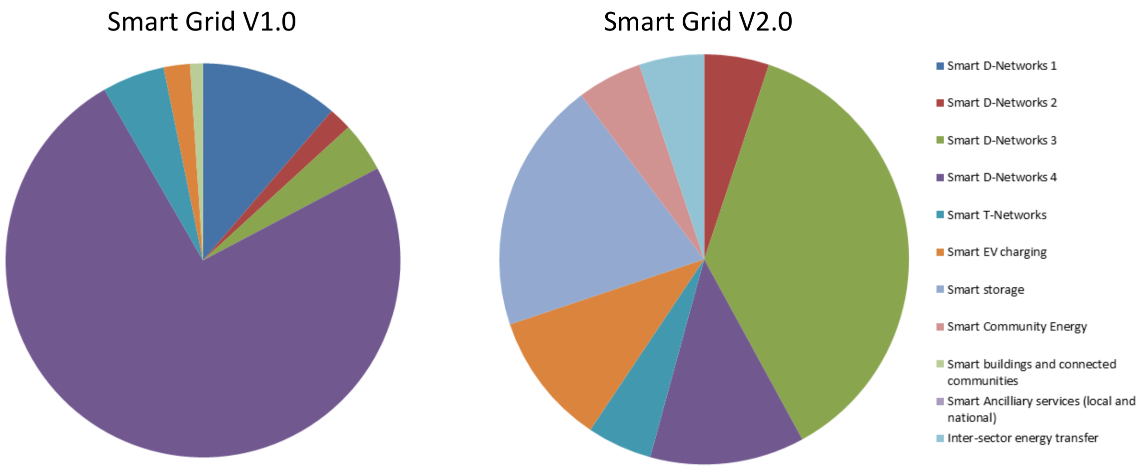


Figure 8.37 Summary of investment by smart solution set (top down)

9 Conclusions

9.1 Key Findings

1. The output of this work has produced a fully populated, complex and highly detailed model
    a. The model has a large number of configurable parameters (or "moving parts")
    b. It requires a number of inputs to function appropriately
    c. The model has been produced with contribution from five organisations (the delivery partners) and comprehensive data from Network Operators throughout GB
    d. It is still very much "a model" and as such there are assumptions and gaps within it. It does not present a conclusive answer as regards smartgrids, but it does help to make the picture clearer
2. This forms part of a wider iterative process
    a. The output of this project should not be regarded as a replacement for, or alternative to, activities being carried out within Ofgem's LCN Fund projects
    b. It is a framework that allows results from such projects to be captured and collated thus allowing appropriate comparisons of the applicability of different smart solutions in different situations
3. Headline outcomes
    a. While initial LCT uptake (within RIIO-ED1) is fairly gradual, this accelerates rapidly through the mid-2020s (RIIO-ED2)
    b. This will have a significant effect on distribution networks which are not designed to cater for this level of technology penetration
    c. Certain network types will be affected more severely than others, but no network is immune to the changes that will be faced
4. In detail
    a. LCT demand, particularly that of EVs and HPs, is significantly larger than that which is used to design today's networks. The After Diversity Maximum Demand (ADMD) of domestic properties (in particular) will go up
    b. Considerable energy efficiency gains are expected to come for certain load types over the next 20+ years, but not for EVs and HPs. Hence these loads will start to dominate
    c. Whilst the network is likely to see some voltage problems in the early years arising from the connection of EVs and HPs, load management will start to become a dominant driver as clustering on a given feeder takes effect
    d. PV mainly drives a voltage problem (high volts during the middle of the day when demand is low)
        i. This is based on the present statutory voltage limits and the fact that distribution transformers tend to be fixed at a tap position at the upper end of this range
    e. Fault level investment (in our model) is driven more by solution deployment than LCT deployment
        i. modern LCTs don't tend to give high fault current contributions
        ii. more transformers necessitate the splitting of the network (minor works or other forms of mitigation) to maintain fault levels within predefined limits

5. Smart solutions appear to represent good value and are well-suited to both high and low LCT uptake scenarios
    a. Smart and conventional blends are more cost effective for high uptake figures, as there are more options available to balance network needs with solution costs. This emphasises that the smartgrid is not a single solution, more the integration of multiple solutions
    b. Smart solutions tend to be smaller and less disruptive to society. The model underplays the societal impact of disruption – whilst this is included in determining the merit order of solutions, it is not brought out explicitly as an output. The cost of excavating and replacing over 85,000km of LV underground cable or overhead line (together with 25,000km of HV and 10,000km of EHV) by 2050 would not be trivial
6. Top-Down looks to offer the best value of the three investment strategies
    a. Although expensive up front, the benefits are soon recovered if these core forms of infrastructure can allow solutions to be deployed in a more cost effective manner over a period of time
7. Clustering at levels similar to that seen through adoption of PV can have beneficial effects in that it can provide a smoother investment profile
    a. Higher levels of clustering bring investment forward while having minimal effect on the cumulative investment required over the entire period
    b. No clustering (even distribution of LCTs) results in blocks of investment as the network manages to accommodate the penetration levels before simultaneously reaching capacity in multiple locations
8. Solutions
    a. Meshing of networks, either in a permanent or temporary arrangement, (if the costs used in this model are proven) appears to be a very strong candidate solution
    b. Where demand is increasing over time, DSR works well as a short term solution only; and the costs of DSR need to be low in order for it to be cost effective against other solutions
9. Other
    a. The complexity of designing and operating a network will increase. There will be additional requirements in terms of training of staff, preparing new policies and procedures relating to the innovative solutions etc, which are not within the scope of this project and no attempt has been made to capture the costs associated with these activities. However, these factors would need to be considered ahead of any widespread deployment of smart solutions on networks.
    b. Nationally-driven DSR, where applied, can provide benefits to the DNO network, but its use appears to be highly cost sensitive. At the modelled 'customer inconvenience' cost of 20p/kWh, use is limited. It would be worth exploring this in more detail to understand the extent to which customers would be accepting of DSR at a lower rate.
    c. The model does not take account of any regulatory treatment which may bias certain solutions in the cost function (e.g. equalised incentives)

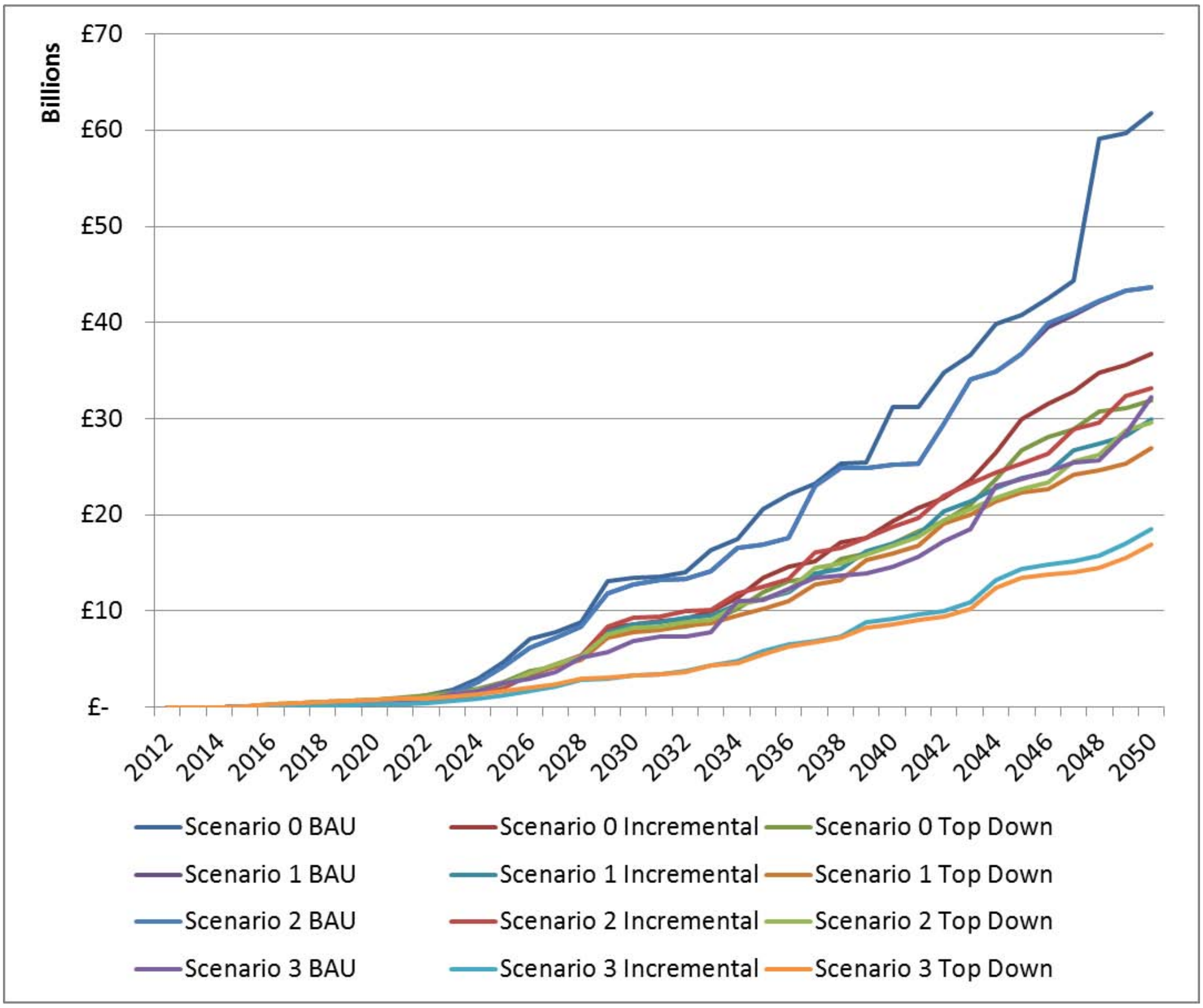


Figure 9.1 Cumulative investment profiles for all scenarios and all investment strategies

9.2 Informing RIIO-ED1

The analysis carried out for the WS2 report and study suggested that smart grids are likely to be more cost effective than conventional investments alone out to 2050. However, it also concluded that there is less evidence to support smart grid investment in the short term, and there is a lack of evidence to inform decision as to whether an up-front or incremental investment strategy should be taken.

The WS3 model is significantly more granular, and has been populated with a more robust set of data. It is therefore possible to expand on the conclusions of WS2, and focus, specifically on the implications for RIIO-ED1 and beyond.

In previous price control periods, investment on networks has fallen into two main categories:

- **Load related expenditure (LRE)** – investment driven by changes in demand, i.e. that in response to new loads or generation being connected to parts of the network (connections expenditure) and investment associated with general reinforcement. LRE was £1.8bn in DPCR5[48].

- **Non-load related expenditure (NLRE)** – other network investment that is disassociated with load. The dominant area of investment in this category is asset replacement (76% of the NLRE for DPCR5). NLRE was £4.6bn for DPCR5.

If the outputs of the model are to be accepted, investment to support the transition to a low carbon economy will needed in addition to these two areas of spend.

9.2.1 Investment Boundaries

The boundaries of investment (excluding any pre-emptive top-down investment) for the RIIO-ED1 period have been shown to lie between the BAU investment strategy for Scenario 0 (All High), and the incremental-smart strategy for Scenario 3 (Low), as shown in Figure 9.2.

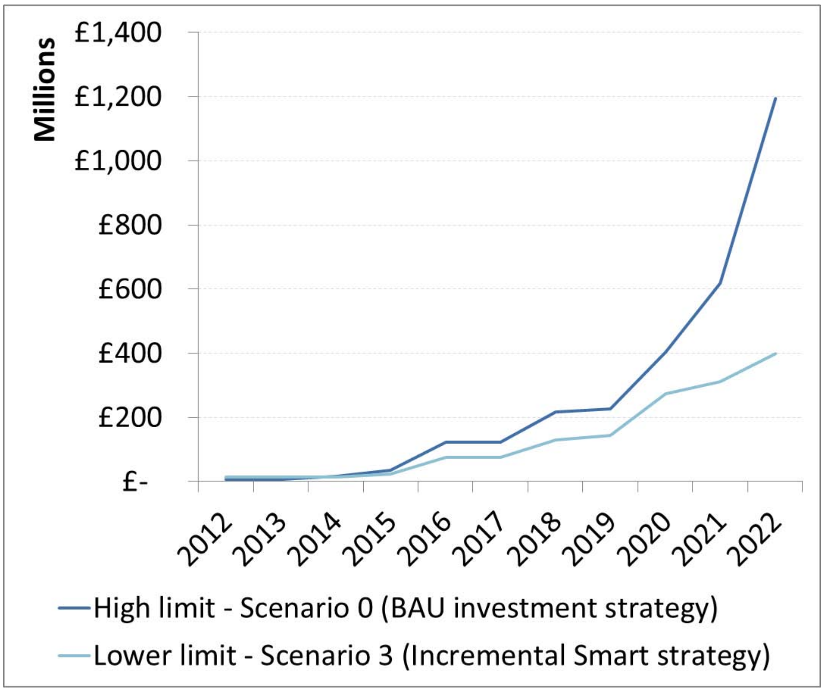


Figure 9.2 Totex investment (gross cumulative) boundaries for the RIIO-ED1 period associated with facilitating the Low Carbon Technology update

Low Carbon related investment in the first half of RIIO-ED1 is relatively light, but increasing throughout the period. The investment then ramps up significantly for all modelled scenarios by the end of RIIO-ED2 (Figure 9.5 – note the change of scale on the graph).

[48] Electricity Distribution Price Control Review - Final Proposals, Ref 144/09, Dec 2009, Ofgem: http://www.ofgem.gov.uk/Networks/ElecDist/PriceCntrls/DPCR5/Documents1/FP_1_Core%20document%20SS%20FINAL.pdf

NB. The costs extracted are based on the split of Ofgem baseline (pre-IQI) and exclude costs of indirect staff and non-operational capex, and real price effects (i.e. the cost of raw materials over time).

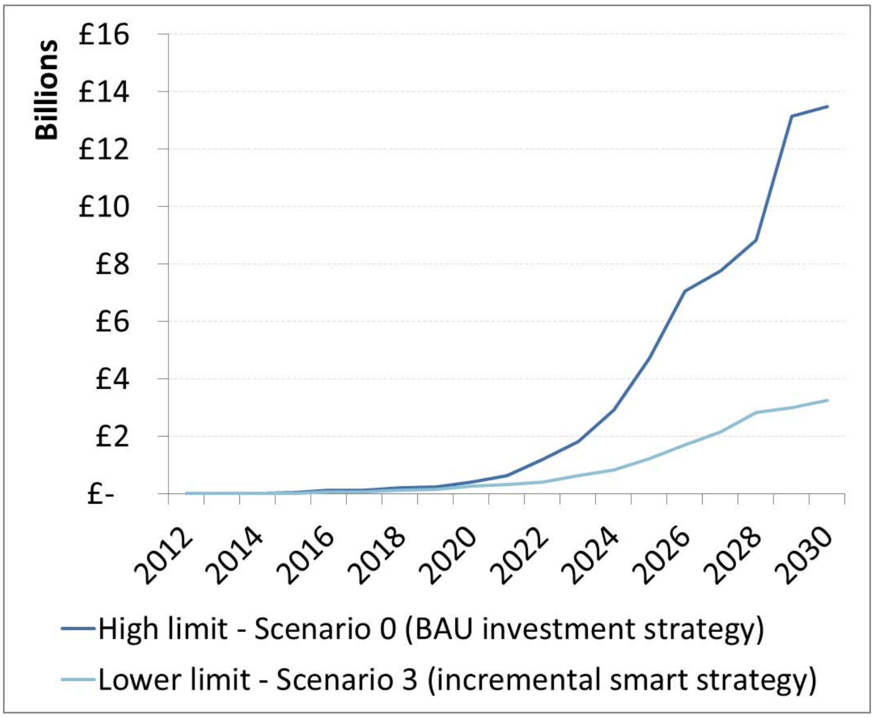


Figure 9.3 Totex investment (gross cumulative) boundaries for the RIIO-ED2 period associated with facilitating the Low Carbon Technology update

Combining these projections together with illustrative data for load and non-load related investment[49], is shown in Figure 9.4.

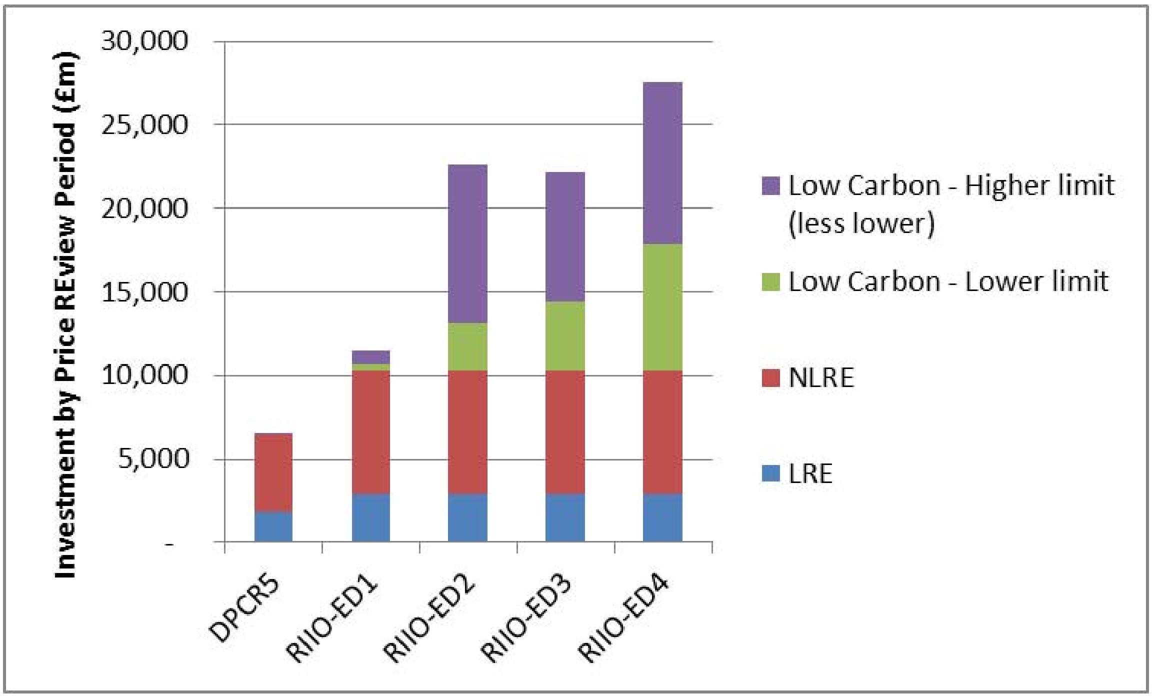


Figure 9.4 Gross GB network related investment for the next four RIIO periods

It is again noted that the Low Carbon related investment driven from this model is dominated (c98% of 2050 figures) by the uptake of technologies such as EVs, HPs and PV from the input scenarios. This is in addition to Load Related Expenditure (LRE), which, as the model does not consider load

[49] LRE and NLRE have been simply scaled by 8yrs/5yrs to correlate to the longer Price Control Periods for RIIO in this illustration.

churn (e.g. the connection of a large commercial load, or biomass plant), is not factored into this result.

Gross costs have been selected in the above figure, as they identify the relative investments between different activities over the future price control periods. They are particularly helpful in drawing out any potential delivery implications of facilitating the transition to low carbon.

According to the projections for Low Carbon related investment from this model, the rapid ramp up in RIIO-ED2 is likely to pose a significant challenge to DNOs. As even at the lower end of the investment scenario projections, the Low Carbon related costs is roughly equal to the annual LRE in DPCR5 and could, at worst case, exceed NLRE in the ED2 period. The investment profile then remains broadly static through ED3, increasing again in ED4 (although it is noted that the results this far out are subject to significant uncertainty, and should be treated with caution).

9.2.2 Candidates for 'No Regrets' investment

Under the RIIO framework it is noted that Ofgem are looking to focus on long term value for money, rather than solely the 8 year price control period.

Based on the input assumptions, the model is showing a slight bias towards the top-down smart investment strategy being optimal over the longer term. This being the case, the model implies that investment will need to be undertaken for a range of enabler technologies in the RIIO-ED1 period, in order to ensure it is available when needed (e.g. the second half of ED1 and into ED2).

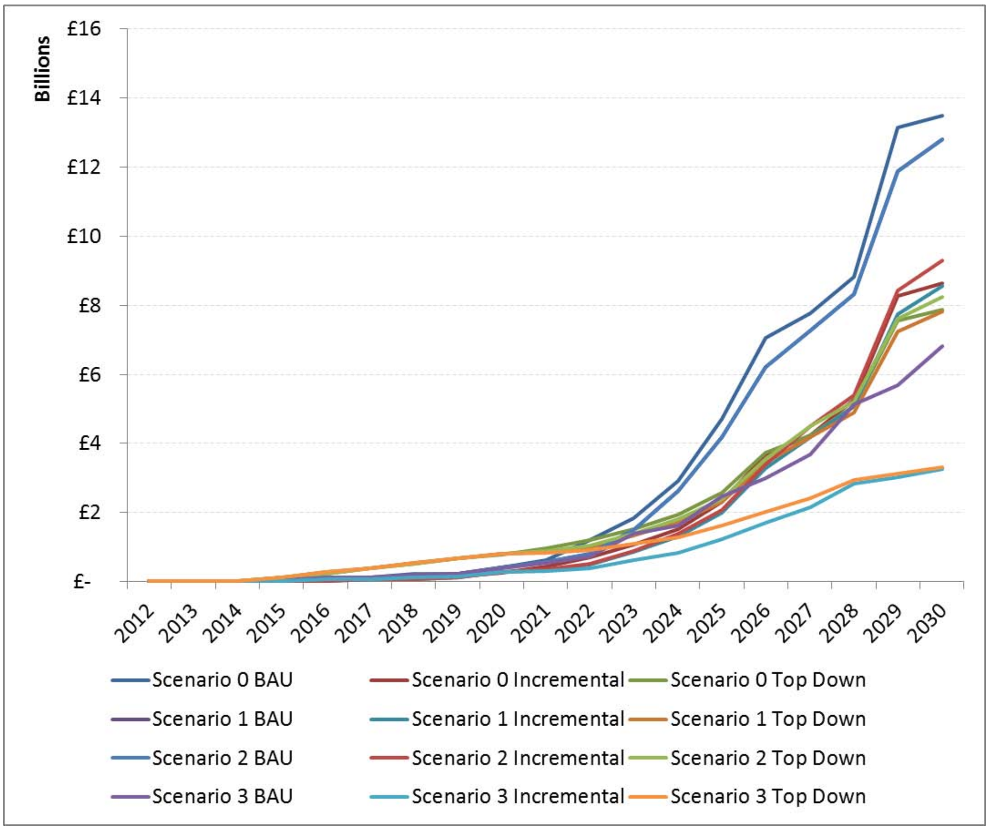


Figure 9.5 Totex investment (gross cumulative) of all scenarios until the end of RIIO-ED2 period associated with facilitating the Low Carbon Technology update

The model is not particularly sensitive to the up-front cost of the enablers (modelled at c£500m (including optimism bias) ±50%) but this project has highlighted that data on enablers, both in terms of which enablers to select and their deployed costs on a GB scale, is sparse. It is recommended that the specifications of enabler technologies, and their costs are reviewed further by the Smart Grids Forum.

RIIO-ED1 poses a transition period, where both incremental and top-down investment may have to be carried out side-by-side. For example, incremental deployments may be needed to provide necessary headroom in areas of networks where high clustering is taking place, at the same time as deploying enabler solutions for when larger penetrations of LCT appear.

There is a need to continue to press for solutions that would be fit for mass deployment in ED2 and ED3. Ofgem took bold steps in DPCR5 with the world-leading introduction of the Low Carbon Networks (LCN) Fund to stimulate the delivery of innovation. This is having positive effect in the engagement, at senior level, of all GB DNOs in the development and roll out of a range of solutions. The WS3 model provides an ideal platform for both testing the application of solutions, and as a checking facility to collate findings of LCN Fund projects (and their successors under RIIO) with an updated set of validated solutions (e.g. deployment costs, headroom release, merit costs, etc).

9.2.3 Availability of the model to DNOs

The model has, unashamedly, a large number of variables as its inputs. These are all deemed necessary in order to produce a valid output to such a complicated, multi-dimensional problem. These variables have been documented in Appendix A, but there has been some nervousness raised by Network Operators about ensuring the data remains valid, and that errors are not inadvertently introduced. Measures have been taken to make the model as transparent as possible, and assist users in understanding the inputs or sensitivities they are operating at any given time.

As an output of this project, two copies of the model will be made available under software-licence to ENA: one for the GB case, one for an individual DNO licence, together with an accompanying user guide. They will both come complete with a set of pre-populated data. In the case of the GB model all assumptions will be as per this report (default case), and in the case of the licence specific model they will contain data from the synthetic DNO model. Both models will contain all scenario data and regionalisation data available at time of publication.

It is the understanding of EA Technology that ENA will sub-licence and issue copies of the ‘master’ models to the GB network operators. Both versions of the model are fully parameter-based, therefore can be adjusted as better input data comes to light, or if a DNO wants to adjust the model to suit their specific needs. The models are designed in a manner such that this can be carried out without external support, but that EA Technology will retain maintenance responsibility for changes to the functionality of the model(s) through a maintenance agreement.

It is recommended that any changes from the default position (contained in Table 10.1) are documented, with supporting data in order to understand changes from the national picture.

9.3 Suggested next steps

The model created for this project is not intended as an “endpoint”, rather it should act as a framework that can be populated with improved data as and when this data becomes available. The following points outline some of the key next steps that can be carried out to make use of, and further refine, the model:

1. When DNOs populate the licence area model, it will be necessary to ensure that the results obtained from it are consistent across GB. This will be essential to ensure the validity and acceptance of the model in the eyes of key stakeholders including the regulator
2. The LCT profiles and solution costs and headroom release figures are based on assumptions rooted in engineering judgment and the best available data. These should be refined as additional data become available
3. DNOs should continue to make use of LCN Fund projects (and their successors under the Network Innovation Competition (NIC) and Network Innovation Allowance (NIA) planned for RIIO-ED1) to aid in the gathering of this data. This is needed both in terms of solution information, but also in terms of data pertaining to networks (particularly at LV) to ensure the model is as reflective as possible of the various networks across GB
4. The scenarios on which the projected investment levels are based should be reviewed at regular intervals and, where possible, extended such that they are consistent in looking out to 2050
5. It has been observed that policy drivers have a significant effect on LCT uptake levels (the FiT is a strong example of this). The potential impacts of incentives such as the CRC and the Green Deal need to be understood and the model should be refined with any information relating to clustering of LCTs as a result of such policy drivers
6. The model has indicated that networks are capable of accommodating LCT growth during ED1, but investment needs ramp up quickly during ED2. This illustrates the need for pro-active work to be carried out to ensure that certain investments are carried out ahead of need and hence the network will be able to support the LCT growth in the coming years
7. The most effective investment strategy drawn out by the model appears to be that of the "top-down" smart, whereby enabling technology is invested ahead of need. This outcome is based on the assumptions used to populate the model (provided in the supporting Annex to this document). It is recommended that more detailed investigation on the costs of procuring and installing the necessary enabling technologies on their networks is undertaken to allow the benefits of this investment strategy to be realised
8. It is intended that the model be expanded in the future to take account of issues relating to power quality headroom and the effect that various LCTs will have on this, in addition to the other headroom measures of voltage, thermal and fault level already considered
9. Consideration should be given as to whether it would be beneficial to review the cost function used within the model to make it more reflective of potential regulatory and governmental incentives. For example, if there was a driver to make GB a world leader in smart technology, the cost function could be altered to reflect the increased attractiveness of certain smart solutions in line with any policy changes in this area

Summary of Appendices

The following appendices contain further detail of some of the datasets and assumptions taken in the development of the model.

In addition to these Appendices and accompanying Annex is available showing the assumptions taken behind each the Solutions and Enablers used in this model.

10 Appendix A: Modelling Assumptions and Variables

10.1 Schematic Overview of the Model

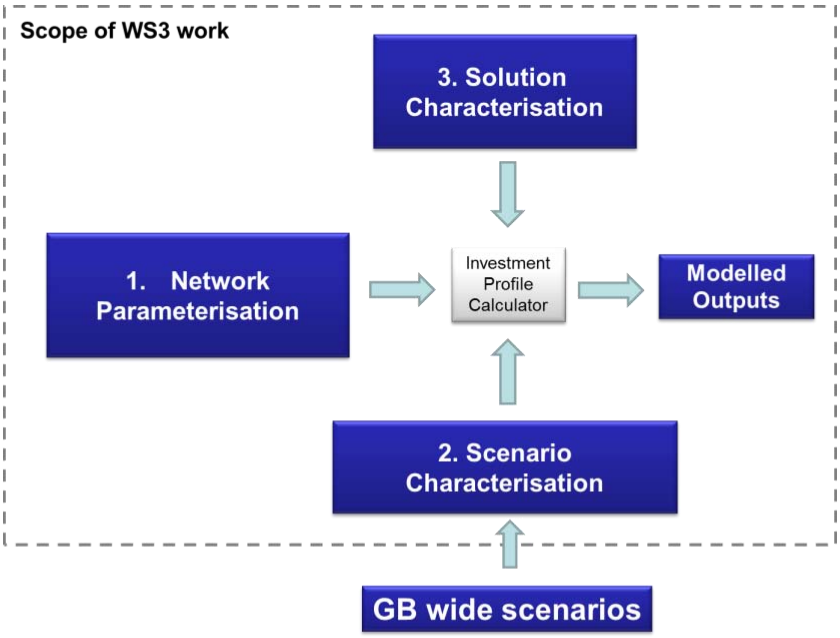


Figure 10.1 Overview of the WS3 model

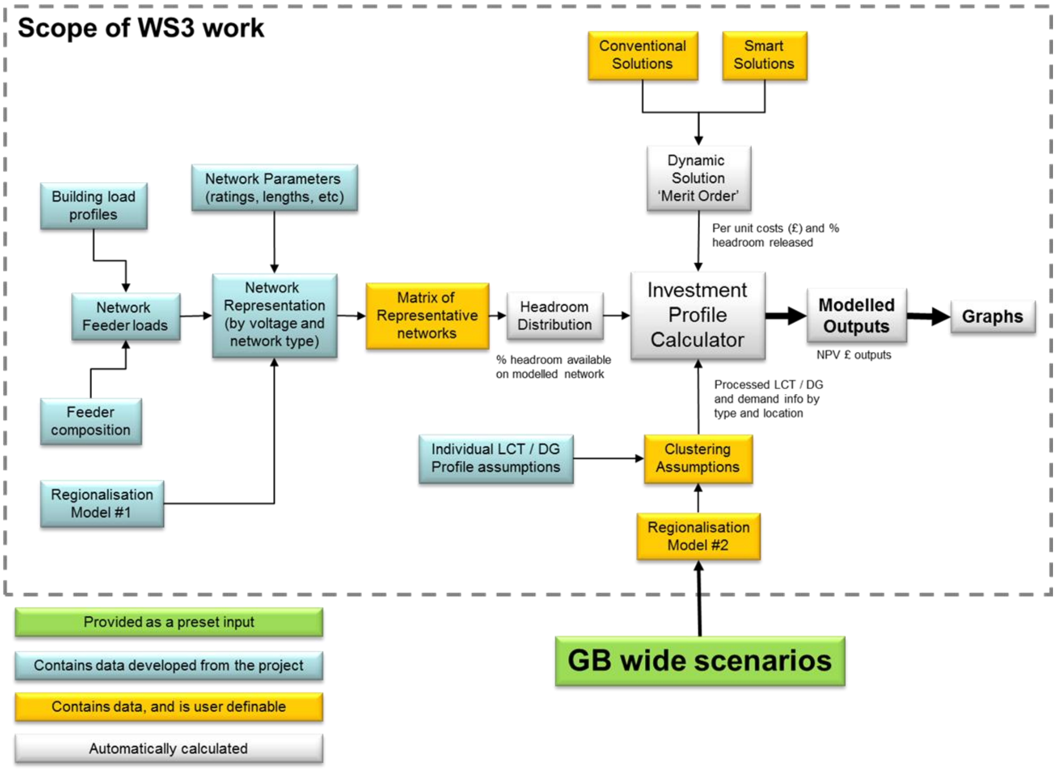


Figure 10.2 Further detail showing the key components of the WS3 model

10.2 Moving parts (variables) within the model

Table 10.1 Summary of the variables and data sources used to populate the model

	What	Data Source	Recommendation to leave fixed or vary
1	Ratings of circuits	○ Taken info from DNO networks ○ DNO community consulted on data integrity	Fixed for GB / Variable in DNO model
2	Number of circuits	○ Based on bottom up analysis of DNO licence areas (LV) ○ IIS return data for DNOs (HV) ○ Corroborated with LTDS data (EHV)	Fixed for GB / Variable in DNO model
3	Apportionment of circuits between type	○ Probable combinations agreed with DNOs ○ Numbers reconciled against bottom-up data	Fixed for GB / Variable in DNO model
4	Starting load and fault level on circuits	○ Info on individual building types ○ Summated along a feeder, based on bottom-up assessment of MPAN data from 4 DNO licence areas ○ Validated against GB demand ○ Fault level data obtained from LTDS data (EHV and HV) and engineering assumptions (LV)	Fixed
5	Load Diversity	○ Building profiles are fully diversified (suitable for EHV, HV and commercial LV) ○ Assumptions taken regarding domestic loads – (factor of 1.4) aligned to common DNO practice, and agreed with the DNO community	Fixed
6	Scaling of the network feeder types from representative DNO licences to form GB equivalent	○ High degree of correlation between feeder composition across the 4 analysed licence areas ○ Fully discussed and agreed with the DNO community	Fixed for GB model / not relevant for DNO model
7	Apportionment of industrial and commercial load by voltage level	○ Apportionment based on an assessment of DUKES data	Fixed for GB / Variable in DNO model
8	Assumption around the 'average' commercial load	○ Assessment of a number of agreed load types, and reconciled with total commercial demand ○ Discussed and agreed with the DNO community	Fixed
9	Apportionment of generation by voltage level and network type	○ Apportionment based on an assessment of DUKES data (Table 5.11)	Fixed for GB / Variable in DNO model
10	Number of days used in the model to represent different times of year	○ 3 days (winter average, winter peak, summer average) ○ Aligned with WS2 and agreed with the DNO community	Fixed / can be modified in DNO model to account for alternative days
11	Assumptions around the ambient temperature	○ Model has capability and datasets for ±5°C for winter conditions (noting that demand is only sensitive to temperature in winter) ○ Base case is taken as -3°C winter peak and 0°C winter average for GB model	Fixed for GB / Variable in DNO model
12	Feeder composition – number and types of buildings per feeder	○ Bottom up analysis of MPANS for the 4 sample DNO licences ○ Agreed with the DNO community	Fixed
13	Feeder composition – load per building type (e.g. demand profile for standard tariff Vs. Economy 7 [PC1, PC2, etc])	○ Bottom up analysis of heat loss profiles for different building types ○ Agreed with the DNO community ○ Validated against both Elexon data and academic research (University of Loughborough)	Fixed
14	Apportionment of feeder demand (high, medium and low) and distribution shape	○ GB model uses average as base-case ○ Normally distributed demand about an average case can be applied (e.g. three cases where demand is 1x 0.8x and 1.2x the normal demand)	Fixed in GB model / variable in DNO model

15	**Energy efficiency assumptions into the future**	○ Assumptions have been taken on energy efficiency of home appliances over time	Fixed
16	**Assumptions around the number of smart appliances (for DSR)**	○ Assumed no smart appliances until 2022 ○ After this, as appliances reach end of life they are replaced with smart equivalents	Fixed
17	**DSR'able load**	○ Analysis of individual load types (split domestic and commercial) with an assessment of when they can be moved from and to in half-hourly blocks across the day	Fixed
18	**Roll off of electric heating and economy 7 type (storage heating) with the uptake of heat pumps**	○ 12.5% roll off for electric heating for every HP deployed (i.e. 1 in 8 HP deployments go into houses previously on electric heating) ○ Until a limit of 50% (i.e. 50% of 2012 electric heating load continues until the end of the 2050 period)	Fixed
19	**GB input data scenarios**	○ WS1 (DECC) for EV, HP, PV penetrations and by type ○ National Grid for wind and biomass generation at HV and EHV	Fixed
20	**Growth in LCT from 2030-2050**	○ WS1 data generally stops at 2030, with the exception of EVs ○ Extrapolation has been undertaken (Element Energy) to expand the dataset out to 2050	Fixed
21	**Regionalisation of scenarios**	○ Bottom-up analysis of the England, Wales and Scotland housing condition surveys ○ Discussed with DNO community	Fixed
22	**Size / number of all LCTs per installation and their fault level contribution**	○ All based on 1 'unit' per household for EVs ○ Allowance made for up to 2 HP units for larger /older houses ○ Allowance made for up to 4 PV units per house ○ Fault level contribution for all LCTs is set to zero as a default, owing to the fact that it is envisaged they will be connected via power electronics	Fixed in GB model / variable by building type in DNO model
23	**Profile of EVs installations**	○ Based on trial data from the TSB's initial findings from the Ultra Low Carbon Vehicle Demonstration project, Dec 2011 and modelling undertaken by EA Technology ○	Fixed
24	**Profile of PV installations**	○ PV data based on real installations in Kew testbed	Fixed
25	**Profile of HP installations**	○ Based on trial data and modelling	Fixed
26	**Clustering of LCTs**	○ All based on PV and FiT data ○ Sensitivities run for no clustering and high clustering	Fixed for GB / Variable in DNO model
27	**Number of years for investment look-ahead**	○ Set as default as 5 years ○ Sensitivities run based on 1 year and 8 years	Fixed
28	**Investment trigger point**	○ Variable trigger points depending on the network type and existing planning standards ○ Discussed and agreed with DNO community	Fixed for GB / Variable in DNO model
29	**Cost of conventional solutions**	○ Representative solutions agreed with the DNO community ○ Variant costs initially based on DPCR5 unit costs and adjusted following dialogue with the DNO community based on recently completed projects	Variable
30	**Cost of smart solutions**	○ Representative Solutions agreed with the DNO community ○ Data taken, where existing, from LCN Fund projects or IFI projects ○ Where no data has been available assumptions have been made and stated in the report and the supporting Annex to this document	Variable
31	**Cost of enablers**	○ Very little data exists for enablers: in most instances assumptions have been made and stated in the report ○ Differences between the enabler costs for top-down (i.e. up front) Vs. incremental (i.e. feeder-by-feeder) deployment	Variable
32	**Linkage between enablers and smart solutions**	○ Manually set based on engineering judgement of which solutions will require which enabler technologies	Fixed
33	**Difference in enabler deployment between incremental and top-down**	○ In top-down – all enablers are installed from 2015-2019 (inclusive), then replaced in 2035-2039 (inclusive) at a cost of 50% initial deployment	Fixed

		○ In incremental – enablers are only deployed as and when necessary (triggered by the solution deployment)	
34	Merit order ‘cost function’ for conventional and smart solutions	○ Factors (e.g. flexibility, cross-networks benefit, disruption) discussed and agreed with the DNO community ○ Assumptions made around the cost of these factors ○ Formula discussed with DNO community	Fixed
35	Merit order settings per Variant Solution	○ Initial data populated based on engineering judgement and iteration of network model to generate ‘sensible’ results	Variable
36	Headroom release data for conventional and smart solutions	○ Based on engineering judgement for the benefits realised per solution deployment	Variable
37	Availability of solutions (by year)	○ Assumptions made around when the solutions would be available	Variable
38	Combinations of solutions (how many in a given year, which combinations are feasible)	○ Up to 5 solutions can be applied in parallel in the WS3 model ○ The feasible combinations of Variant Solutions have been tagged in the model	Fixed
39	Life expectancy of solutions	○ Based on estimates of typical assets	Variable
40	Losses attributable to solutions	○ Based on engineering judgement relating to whether solutions will, for example, increase load on an asset (and therefore variable losses)	Variable
41	Quality of supply benefits attributable to solutions	○ Assessment based on engineering judgement regarding the positive or negative effect that the solution will have on CIs and CMLs	Variable
42	Nationally-driven DSR – payments to customers	○ Set as 20p/kWh on the basis that this is 2x a standard unit of electricity -	Fixed
43	Output costs	○ Only totex cost, for each year of the model ○ No disruption costs are brought out of the model	Fixed
44	Discount rate in model	All set to 3.5% in the model – user definable	Fixed for GB / Variable for DNO model
45	Optimism bias for conventional and smart capex and all opex	○ Aligned with UK Government guidelines and the approach taken for the WS2 report, all results apply an optimism bias of: 44% for conventional solutions; 66% for smart solutions and enablers ○ For operating expenditure a figure of 30% has been applied to all solutions (this is new for WS3, as was not applied in the WS2 model)	Fixed

10.3 What is included and what is not included in the model

Table 10.2 What is included and what is not included in the model

Area	No.	What's included in the model	What's not included in the model	Ability of the model to flex to meet the 'not included' requirements	
				Ease	Comment
A. General: overview					
A	1	Two models: a GB wide and a DNO licence level to provide a view of the national picture (former) and a model that can be honed to an individual DNO licence area (latter)			
A	2	In the GB wide model: • An economic appraisal model, allowing comparison of the net benefits (£) of using smart grids vs. wholly conventional solutions to accommodate different GB-wide scenarios. • A basic assessment of costs and benefits relating to transmission and generation is included in the model, but the focus of the detailed modelling is on the distribution network. • Costs and benefits can either be assessed from a social (UK plc.) point of view, or from a private, DNO only perspective.			
A	3	In the Regional model: as A2, but without the assessment of the costs and benefits relating to transmission and generation.	An ability to feed-back from the DNO model the GB generation mix, and therefore capture wider Value Chain benefits (£)	L	In the 'Regional' model, it is not possible to see the complete GB demand picture, therefore an assessment of cross Value Chain benefits cannot be assessed
A	4	A model capable of running different sensitivity analysis of different GB scenarios or investment strategies			
A	5	Load related investment, based on uncertainty around the deployment of a variety of low carbon technologies	Asset replacement for end of life: the model does not consider any impact of underlying asset health, nor the investment requirements thereof.	M	This could be an area for expansion in the future, but is far from a trivial change.
A	6	A parameter based model of electrical distribution networks and their loads	It is not a load flow model, such as those used for DNO system design / network planning purposes	L	The model is not a load flow engine, but a 'parameter' based system, that compares the network capacity (headroom) to a series of demand curves.
A	7	An indicative investment model outlining the likely quantum of investment both by type of network, and in aggregate to a licence or GB scale (depending on which model is used)	It's not a planning model - it can't tell you precisely where investment will be required	L	This type of model is not able to provide detailed planning data, e.g. which primary transformer(s) or LV feeder(s) to reinforce in a given year.
A	8	A focus on facilitating a variety of low carbon technologies (and associated solutions) from the perspective of the power	Detailed transmission modelling. For example, the following are not included: • Stranded asset	L	It is not a detailed transmission model. To embed such requirements would be

		distribution network	investment and relocation options for TNOs (e.g. SGT deferral) • TSO modelling and the value and benefits of transmission ancillary services		a fundamental change to the structure of the model.
A	9		Stranded asset investments and/or relocation options for DNOs		
A	10	A set of assumptions (one per scenario) around the likely load growth (or reductions) in demand across distribution networks	Underlying load growth scenarios considering a range of background economic models (e.g. how quickly GB comes out of recession)	M	
A	11		Gas networks	L	The model focuses on electrical load. Whilst consideration is given to changes in electrical demand with a transition from gas to electrical heating (e.g. heat pumps at domestic level) it does not consider the implications on the gas network, and would need significant changes to do so.
A	12		Hydrogen networks	L	The change of energy vector from electricity to hydrogen and vice versa has not been included, and is likely to require significant changes to the modelling approach
A	13		Heat networks	L	The model focuses on electrical load. Whilst consideration is given to changes in electrical demand with a transition from gas to electrical heating (e.g. heat pumps at domestic level) it does not consider local heat networks, and would need significant changes to do so.
B. Network Datasets					
B	1	Three network voltage levels: EHV, HV and LV			
B	2	Network variants of the three voltage levels: • EHV – 6 types • HV – 7 types • LV – 19 types incorporating pre-set network and load data based on averages of real GB DNO datasets			
B	3	Expansion capability: The model has been dimensioned to allow for: 8xEHV, 8xHV, 20xLV networks, giving DNOs the ability to add in special cases on a needs-basis			
B	4	Provision for Distributed Generation (e.g. onshore wind, biomass etc.) at HV and EHV voltage levels			
B	5	Three days (weekday) of half-hourly demand profiles considering: summer average,	Weekend demand profiles	L	New profiles would need to be generated

		winter average, winter peak			
B	6	Demand profiles for 17 domestic building types, 8 non-domestic building types plus one profile for unmetered demands (street lighting)			
B	7	An assessment of how building loads differ and will change over time with improvements in appliance energy efficiency, coupled with increased volumes of electrical consumer products			
B	8	Adjustments in demand profiles for winter temperature variation across GB within the range -5°C to +5°C			
B	9	5 GB regions (Scotland, Wales, North of England including the Midlands, South of England, London) to account for regional policy, or geographic changes	Only related to five regions - not a direct read across to the 14 licences	M	Significant redesign would be required to develop a GB-wide model that has the granularity of all 14 DNO licences
B	10	Demand profiles for a single 'average' heat pump which incorporates variation in COP with temperature and the use of top-up heating from electric resistive heater in peak conditions	Different types of heat pump (air to air, air to water, GSHP etc.). Combinations of heat pumps with other secondary heating systems e.g. wood burner	M	Could approximate different HP type by changes to efficiency parameters
B	11	Heating demand profiles based on an 'on-demand' usage pattern	Does not consider heat pumps operating in continuous mode	L	Could generate new profiles based on continuous operation but would be difficult to have a mix of different operating patterns
C. Scenarios					
C	1	An ability to take different national scenarios (as provided by WS1/DECC) of the penetration of low and zero carbon technologies as inputs			
C	2	An assessment of how the GB scenarios will be applied across the five geographic regions outlined in B9			
C	3	An assessment of how the GB scenarios will cluster onto different network feeder types			
C	4	Demand profiles for each of the technologies identified from the WS1/DECC scenario			
D. Solutions					
D	1	Approximately 5 conventional and 20 smart representative solutions, with 71 variants and 72 enablers			
D	2	The solution set within the model has been dimensioned to accommodate 150 different solutions			
D	3	A dynamic 'merit order', considering factors that include: total expenditure, disruption, cross-networks benefit and flexibility			
D	4	Consideration for the replacement of these Solutions as they reach end of life			
D	5	Combinational deployment of up to 3 Solutions at a time			
D	6	A forward forecast to ensure the			

		solution will meet the headroom of n years hence (where n is user definable) – initially set to 5 years			
D	7	A suite of five cost curves to account for different changes in solution price over time			
D	8	An assessment of solution 'tipping points' (deployment volume or £ flags) to highlight the potential for step changes in the deployment of solutions en-masse			
D	9	A simple model to consider changes in losses, quality of supply (CI/CML) as different solutions are deployed			
E. Calculation Module					
E	1	A parallel assessment of: thermal headroom (conductor and transformer), voltage (headroom and legroom), fault level (headroom) for each network type, stepped by the year	Power quality headroom assessment	H	Insufficient data to analyse a starting headroom position for power quality. The addition of a PQ element would not be overly complex and could be an expansion for the future.
E	2	An ability to change all of the base parameters in the model to user requirements (but note caution of doing this without understanding implications)	An expansive dashboard (high level overview) to change all assumptions and details without having to go to every data table		
E	3	A software model that looks and feels like MS Excel, but in underpinned by a C# engine			
E	4	A model that will run on MS Excel 2007 and later versions	It won't run on a mac..!	L	The Apple version of Excel will not run this type of model. Unless changes are made by Apple (outside of the developers control), this will remain a pc only model
F. Generation and DSR					
F	1	Simple merit order stack of up to ten types of large-scale generation, including simple representation of variability of wind generation and ramping constraints.	Full hourly dispatch model of electricity sector.	L	Would greatly increase the complexity of the model.
F	2	Trade-offs between DSR for different uses (to reduce local network vs. system wide generation costs) represented through sequential modelling. Smart meters, which can facilitate dynamic DSR from the mid-2020s, are assumed to have been rolled out in the business as usual case.	Full optimisation of DSR between all different uses.	L	Would greatly increase the complexity of the model.
G. Cost benefit modelling					
G	1	Cost benefit analysis	It's not a financial model – it does not consider the financial treatment, cash flows, P&L, RAV treatment, etc. of monies	M	Not possible in the current model, but the outputs could be developed into the future if this capability was required
G	2		Assessment of option value is not included	M	This capability could be added but would have a highly detrimental impact on running time.
H. Other					

H	1		Indirect costs and benefits (e.g. job creation, impact on the macro-economy of changing energy costs)	L	Not possible in this form of the model
H	2		Assessment of the market arrangements	L	Not possible in this form of the model
H	3		Wider benefits associated with decarbonisation	L	Not possible in this form of the model
H	4		Other non-market goods (e.g. the potential landscape benefits from reduced wirescape)	L	Not possible in this form of the model
H	5		Benefits associated with shorter investment lead times for certain technologies	L	Not possible in this form of the model

11 Appendix B: Network Analysis

11.1 LV network analysis

11.1.1 Definition of LV network loads

Step A

The model incorporates a representation of the low voltage distribution network constructed from a total of 19 typical LV network typologies (LV feeders). These LV network types have been developed to be representative of the diversity of the LV network found in areas of differing character, for example rural versus urban networks and networks serving heavily residential areas versus those feeding business districts or retail parks. In order to define these LV network types, it is necessary to analyse the loads connected to real networks in different parts of the distribution network. This analysis has resulted in a set of 'standard feeder loads', where a standard feeder load is a combination of the basic house types and non-domestic building types that are incorporated in the model. These standard feeder load types have been defined in such a way that when aggregated together in appropriate proportions, they accurately reflect the loads found on wider areas of the real network.

The process undertaken to define the standard feeder loads is shown in Figure 11.1, below.

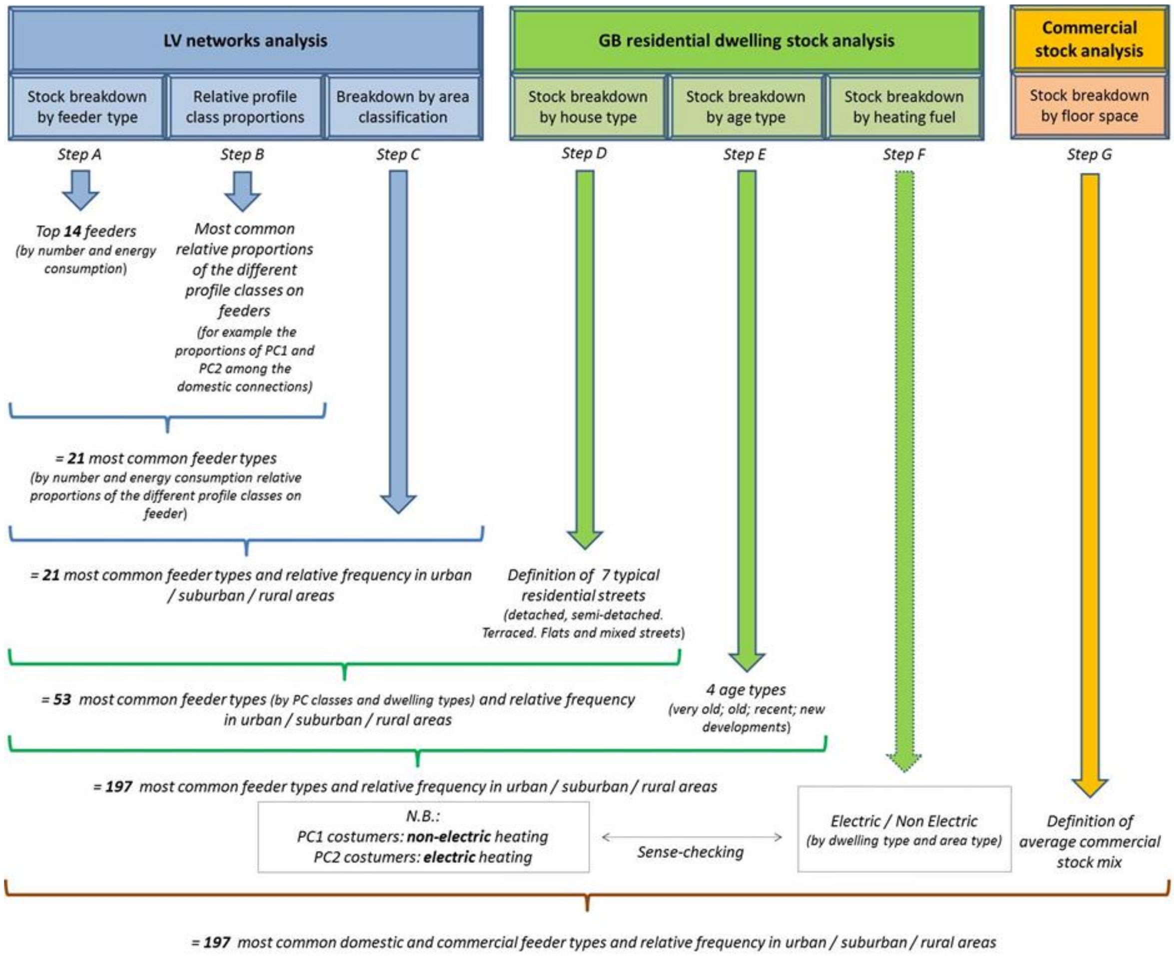


Figure 11.1 Schematic of the process undertaken to define typical feeders (Source: Element Energy)

As shown in the schematic above, there are two main components of the analysis underpinning the definition of standard feeder load types. The first strand of the analysis involved assessment of a large dataset provided by the distribution network operators (DNOs), detailing connections on LV feeders in terms of the number and mix of customer types on each feeder (where customer type is defined in terms of profile class 1 to 8 or as a half-hourly connection) and the estimated annual consumption (EAC) by each customer type. While this data enabled an identification of typical feeder configurations in terms of overall numbers of connections and mixes of profile classes, it gave no insight into the types of buildings connected, e.g. the mix of house types or type of non-domestic properties. The second strand of the analysis was then undertaken to develop an understanding of the composition of the building stock at a regional level, as a means of populating the standard feeder loads with a representative mix of building types.

The methodology has therefore principally been based on the analysis of data from three sources:

1. The LV network data provided by the Distribution Network Operators (DNO) partners in this project
2. The English, Welsh and Scottish House Condition Surveys
3. Rateable Value data published by the Valuation Office Agency

The analysis of this data is described in further detail below.

11.1.2 Detailed analysis of the feeder population of existing LV networks

This task required the analysis of data for over 350,000 LV feeders in seven licence areas (Northern Power Grid – Northeast and Yorkshire; Electricity North West; Western Power Distribution – South West, East & West Midlands and Wales). The ‘feeder stock’ in each licence area was classified by feeder type. A **feeder type** is defined by the profile class of the customers served by the feeder. For example, a feeder serving only profile class 1 & 4 customers is named ‘Type 1&4’ feeder (see Figure 11.2, below).

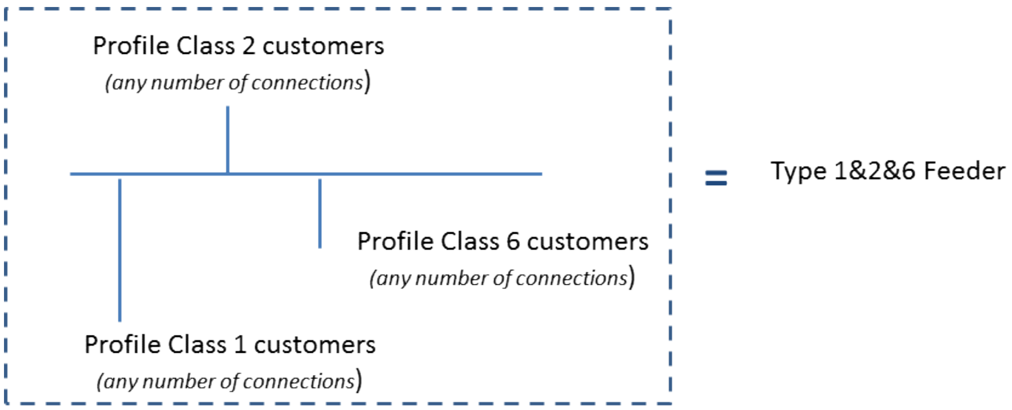


Figure 11.2 Definition of a feeder type by the profile class of the customers served by the feeder (Source: Element Energy)

The analysis of the LV network data provided by the Distribution Network Operator (DNO) partners in this project focused on:

i. Number of feeders per LV network and feeder type
ii. Total consumption (kWh) per LV network and per feeder type
iii. Number of connections per LV network and feeder type
iv. Average consumption (kWh) per feeder type and LV Network

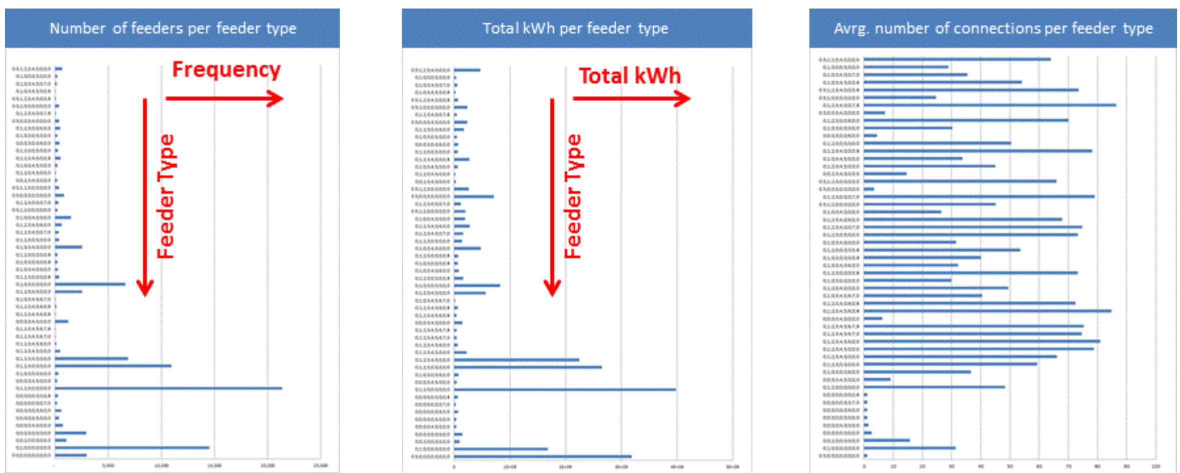


Figure 11.3 Example of the output produced during the feeder stock analysis (Source: Element Energy)

The objective of this analysis was to identify a set of common feeder types that could be used as the basic building blocks of a model of the LV networks across the GB regions. To this end, the analysis of the feeder data provided by the DNOs concluded that:

1) The DNO networks presented a very similar breakdown in term of feeder types

2) A large proportion of the whole feeder stock (i.e. all LV feeders within a particular licence patch), the number of customers connected and total energy consumption can be represented by a very limited number of feeder types. More precisely, the analysis concluded that the top 10 most frequent feeders reported in the DNO datasets were able to account for circa 83% of the total number of feeders and circa 76% of the total energy consumption (see Figure 11.4 below)

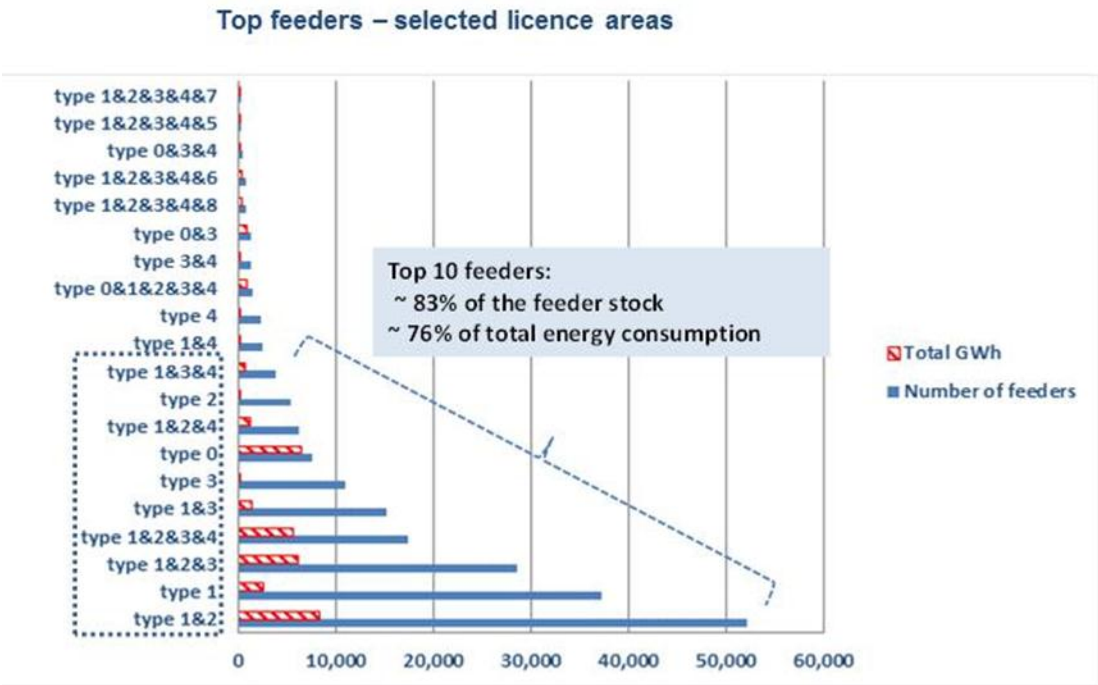


Figure 11.4 The top 20 feeder constituting the bulk of the feeder population in three of the network areas analysed (Source: Element Energy)

These top ten feeders are predominantly domestic (profile classes 1 and 2), half-hourly (here labeled as profile class 0), commercial (profile classes 3 and 4) and mix of domestic and small commercial (i.e. a mix of profile classes 1, 2, 3, 4). For this modeling exercise, we have considered 13 types of feeder that have been identified as most relevant in terms of their frequency of occurrence in the LV networks, the proportion of overall electricity consumption and overall number of connections they account for. These 13 most relevant feeder types are listed in Table 11.1, below.

Table 11.1 List of the 13 existing feeder types included in the modelling exercise

	Feeder Type	Customer types connected (PC = Profile Class)
1	type 1	PC 1 domestic customers (unrestricted)
2	type 2	PC 2 domestic customers (economy 7 and variations)
3	type 3	PC 3 commercial customers (unrestricted)
4	type 0	Half-hourly commercial customers connected at LV level

5	type 1&2	PC 1 and PC 2 domestic customers
6	type 1&3	PC 1 domestic and PC3 commercial customers
7	type 3&4	PC 3 and PC 4 commercial customers
8	type 0&3	Half-hourly and PC 3 commercial customers
9	type 1&2&3	PC 1 and PC 2 domestic and PC 3 commercial customers
10	type 1&2&4	PC 1 and PC 2 domestic and PC 4 commercial customers
11	type 1&2&3&4	PC 1, PC 2 domestic and PC 3, PC 4 commercial customers
12	type 0&1&2&3&4	PC 1, 2, 3, 4 and half-hourly customers
13	type 1&2&3&4& X	PC 1, 2, 3, 4 and other PC classes customers

An analysis of the average number of connections per feeder type has also demonstrated similarities between different distribution network areas. There are, however, differences in the number of connections depending on the area character, i.e. between rural and urban areas. This led to definition of differing standard feeder load types for urban, suburban and rural networks.

Step B

In this step the analysis investigated the relative proportions of the most common profile classes (PC) on the 13 most relevant feeders defined above:

- The proportions of PC1 and PC2 among the domestic connections and
- The proportions of PC3 and PC4 on the feeders serving mixed (domestic and commercial) and commercial only connections

This analysis was important in defining the standard feeder types not only in terms of profile classes and numbers of customers connected, but also the relative proportions of the different profile class connections. This is particularly relevant in the case of PC2 and PC4, as the prevalence of electric heating in these profile classes results in very different demand profiles in comparison to PC1 and PC3, respectively.

Example results of this analysis are shown below in Figure 11.5 for the Western Power Distribution-South West network. These charts show the frequency of certain ratios of profile classes occurring within the groups of common feeders.

The shapes of the distributions seen in Figure 11.5 are highly reproducible across the other network areas analyzed (in some cases the Type 1 & 2 feeders tend to be even more ‘skewed’ toward heavily PC1 dominated feeders).

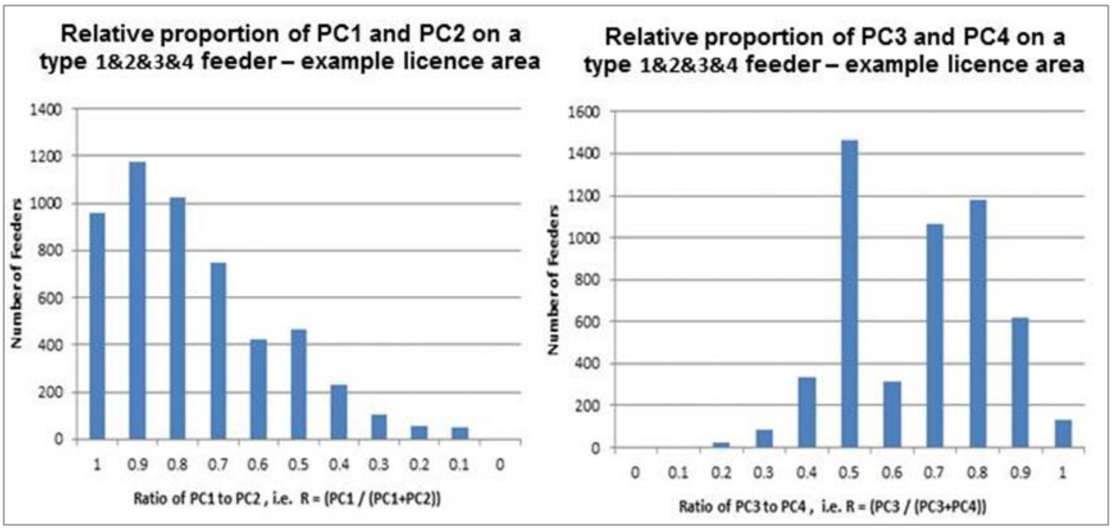


Figure 11.5 Charts for feeder type 1,2,3,4 (Source: Element Energy)

[Note re Figure 11.5 – i.e. the group of feeders that have all these profile classes connected. The ratio of PC 1 and PC2 on these feeders is still weighted toward strongly PC1 dominated feeders, although a higher penetration of PC2 appears to be more common than in the case of the purely domestic feeders. The shape of the distribution of the ratio of PC3 and PC4 on these feeders is interesting, with a strong spike at 50:50 (approximately an even mix), but overall a weighting toward PC 3 dominated feeders.]

The analysis described in Steps A & B resulted in the definition of a set of standard feeder types that would form the basic building block of the modeling of the LV networks. These standard feeder types are defined in terms of mix of profile classes connected, relative proportions of profile classes and overall number of connections. In order to use these standard feeder loads to build a representative model of the LV networks, information is also required on the proportions in which they should be aggregated together, as described in the following step.

Step C

The analysis of the feeder stock also identified the relative frequency of occurrence of the feeder types across the GB regions. Furthermore, it was possible to understand the relative distribution of the feeders in areas of different character (rural, suburban and rural) within each GB region. In this manner, the composition of the overall feeder stock could be described by the short-list of feeder types and their relative proportions in the different regions and areas of different character.

This classification of feeders by the rural / urban character of the area has been achieved by linking the postcodes of the distribution substations (supplied by the DNOs) to the district code of the local authority where they are situated. The government Local Authority Classification datasets (for England, Scotland and Wales) have then been used to classify the feeder location as rural, urban or sub-urban (see Figure 11.6 below)[50].

[50] Due to the granularity limits of this database (minimum detail: Local Authority) and the only partial integrity of the network datasets received, the Urban/Suburban/Rural splitting is of course only approximate.

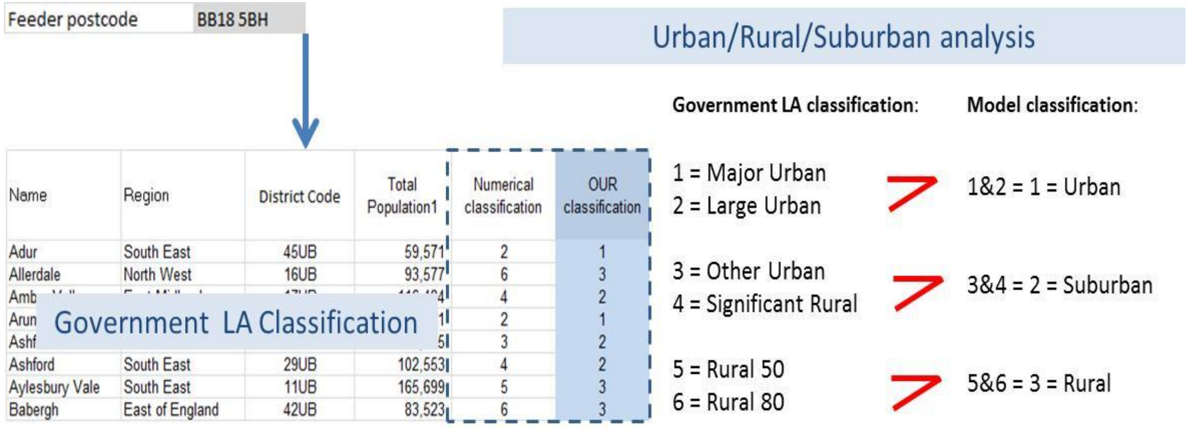


Figure 11.6 Schematic of the urban/suburban/rural feeder classification process adapted

Using the Government LA Classification database, the analysis concluded that:

- The large majority of the connections are generally located in Urban or Suburban areas. Of the regions assessed, the South West was an exception to this, with a higher number of connections in areas classified as rural (Figure 11.7, below)

- The most common feeder types (as described in step A) also appear to be similar between areas of different character, i.e. the same feeder types tend to dominate in areas of urban, sub-urban and rural character (Figure 11.8, below)

- There are some differences in numbers of connections per feeder depending on the area classification, for example domestic feeders with low numbers of connections (10 or less) are more prevalent in rural areas

NOTE

The Distribution Network Operators datasets provided did not cover all licence areas. The following methodology has been adopted for those regions that were not covered by the data provided :

- The frequency of the most relevant feeders across the ‘unknown’ networks is assumed to follow the nearest ‘known’ network region. This is assumed to be a good proxy as the analysis undertaken (see Step A) concluded that: 1) the networks present a very similar breakdown in term of feeder types and 2) a large proportion of the whole feeder stock, number of connections and total energy consumption can be represented by a very limited number of feeder types

- The distribution of the feeders across area of different character within the ‘unknown’ networks will follow the urban, suburban, rural breakdown for residential dwellings as described by the English, Scottish or Welsh House Condition Survey for the relevant Government Office Region (GOR)

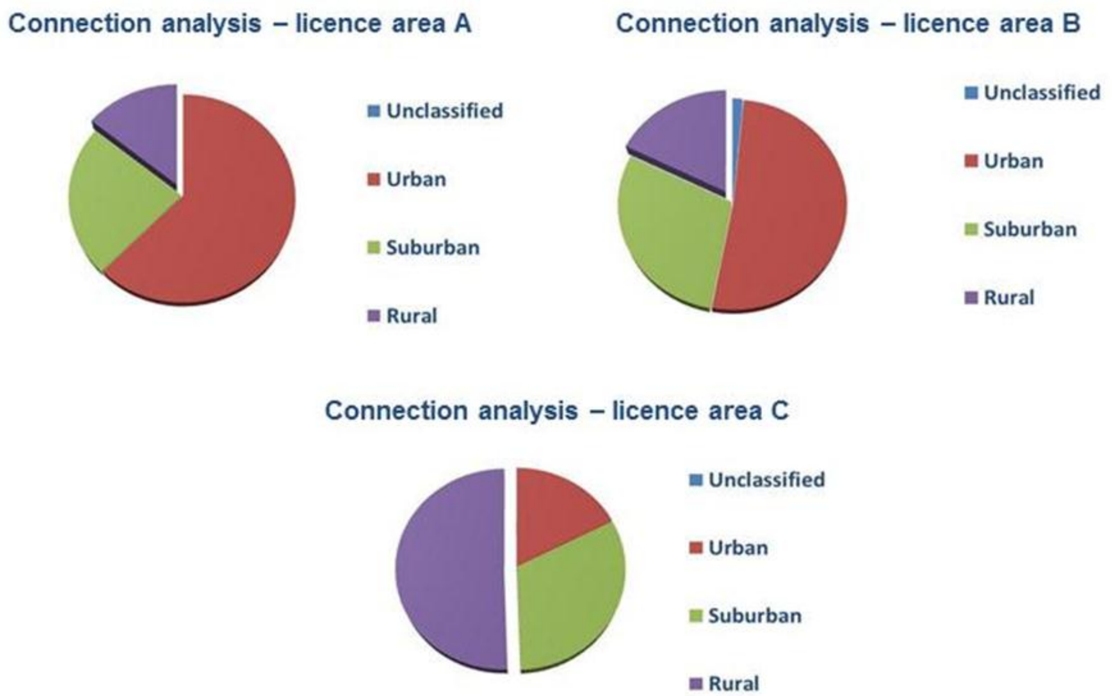


Figure 11.7 Results of the split of number connections between area types (urban/suburban/rural) for three of the network analyses (based on the Government LA Classification datasets) (Source: Element Energy)

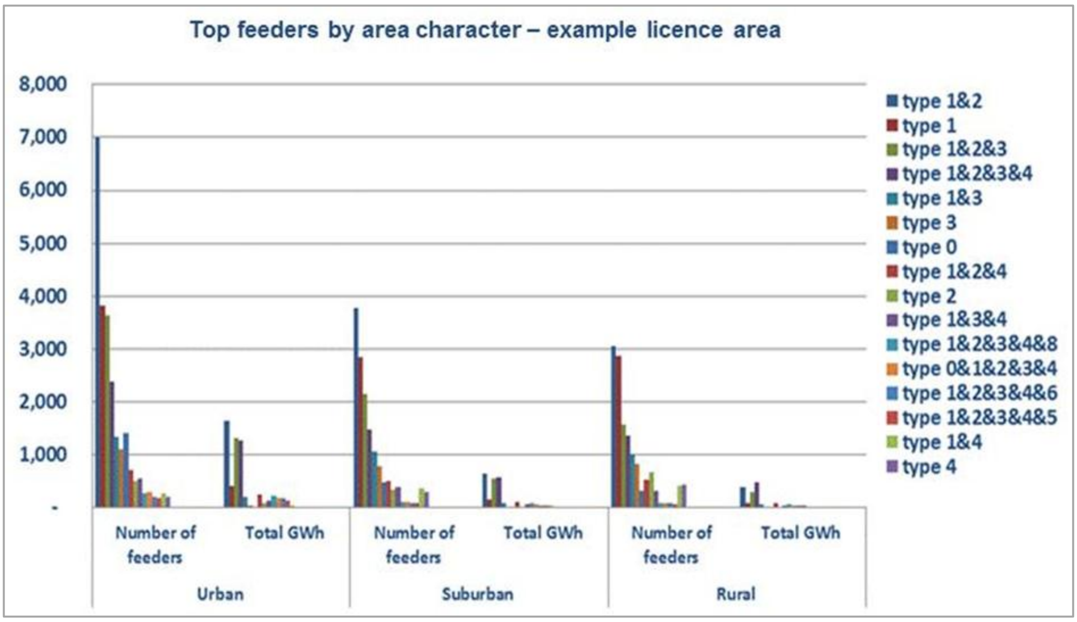


Figure 11.8 Results from the top 20 feeders' analysis in urban/suburban/rural areas for sample licence area (Source: Element Energy)

[Note re Figure 11.8 - This analysis demonstrated strong similarities across the three networks.]

The outcome of the analyses described in Steps A to C was a short-list of standard feeder load types, defined in terms of number of connections, mix of profile classes and their relative frequency within the overall feeder stock of the five GB regions. Standard feeder load types typical of urban, suburban and rural areas were defined.

11.1.3 Detailed analysis of the English, Welsh and Scottish House Condition Surveys

Step D to F

To accurately determine demand profiles at LV feeder level, it is necessary to understand the type of customers on each feeder. Estimated profiles for each of these customers can then be appropriately aggregated (taking into account diversity) to obtain the total demand at LV feeder level.

Given that the Department of Energy and Climate Change (DECC) scenarios include a significant uptake of new electric heating technologies (heat pumps), it is important to consider not just the building type, but also the properties of the building (primarily heat loss), which influence demand.

To this end, we have analyzed the full domestic dwelling datasets produced by the English, Scottish and Welsh *House Condition Survey (HCS)*[51]. These surveys contain a wide range of information on the existing residential dwelling stock, such as:

- Dwelling age;
- Dwelling type (flat, terraced, detached, semi-detached);
- Primary heating fuel (gas, electricity, LPG, other);
- Location (urban / suburban / rural areas).

We have use the first three categories to initially subdivide the GB dwelling stock into 48 dwelling types based on the following parameters:

Age	Definition	Type	Variations included	Primary heating fuel	Variation included
New build	Post 2012	**Detached**		**Gas**	
Recent	1980 - 2012	**Semi-detached**		**Electricity**	Off-gas / On-gas areas; with / without storage heaters
Old	1919 - 1980	**Terraced**		**Other (bottled gas, wood etc)**	Off-gas / On-gas areas
Very Old	Pre 1919	**Flats**	High-rise / Low-rise / Tenements		

Figure 11.9 Classifications used to sub-divide GB existing dwelling stock and new build into 48 distinct house types (Source: Element Energy)

For each dwelling type, the analysis focused on:

[51] English HCS: available here; Scottish HCS: available here; Welsh HCS: available here.

1. Number of dwellings per dwelling type (step D), age (step E) and main heating fuel (step F) for the stock in areas of each area character (urban / suburban / rural)
2. Average usable floor area per dwelling type (m^2)
3. Percentage of dwelling having storage heaters (per dwelling type)
4. Percentage of dwellings in off-gas areas (per dwelling type)
5. Percentage of flats being high-rise flats
6. Percentage of flats being Scottish tenements

- **Point *1*** was performed to inform the feeder definition process (steps D to F as described in Figure 10.1) by defining an appropriate number of different dwelling types. The dwelling types have been chosen to provide sufficient variation to represent the loads on the standard feeders whilst limiting the number of types to a manageable number.

- **Points *2 to 6*** were performed to inform the load profile definition process (see Appendix C for a description of the building demand profile modelling) by providing additional information on, for example, the insulation standards of the dwellings, average floor space and heating system.

The analysis of the English, Scottish and Welsh housing condition surveys has shown that a limited number of house types, comprising a mixture of type, age and primary heating fuel, can be used to represent approximately 88% of the GB housing stock (see Figure 10.9, below).

For this modeling exercise, we have considered 24 existing house types, defined in Table 11.2 below, and 8 new-build house types.

Table 11.2 List of the 24 existing house types included in the modelling exercise

	Type		Type
1	Recent detached ; gas or other heating fuels	13	Recent detached ; electric heating
2	Old detached ; gas or other heating fuels	14	Old detached ; electric heating
3	Very old detached ; gas or other heating fuels	15	Very old detached ; electric heating
4	Recent semi-detached ; gas or other heating fuels	16	Recent semi-detached ; electric heating
5	Old semi-detached ; gas or other heating fuels	17	Old semi-detached ; electric heating
6	Very old semi-detached ; gas or other heating fuels	18	Very old semi-detached ; electric heating
7	Recent terraced ; gas or other heating fuels	19	Recent terraced ; electric heating
8	Old terraced ; gas or other heating fuels	20	Old terraced ; electric heating
9	Very old terraced ; gas or other heating fuels	21	Very old terraced ; electric heating
10	Recent flats ; gas or other heating fuels	22	Recent flats ; electric heating
11	Old flats ; gas or other heating fuels	23	Old flats ; electric heating
12	Very old flats ; gas or other heating fuels	24	Very old flats ; electric heating

The proposed domestic buildings cover each of the 4 standard types (detached, semi-detached, terraced and flats) for 4 age bands (very old, old, recent and new) and 2 primary heating fuels (electric/non electric heating). High rise are considered separately as these predominantly fall into the ‘old’ age category.

This level of detail is required in order to capture the range in heat loss between different constructions, size and age of houses (see for example Table 11.3, below). It is also important to inform the analysis of where in the building stock new low carbon technologies such as photovoltaics and heat pumps are likely to be taken up. For example, flats are less likely to have ground source heat pumps or solar PV, wall insulation applied to a terraced house will have less of an effect than on a detached house, etc.

Table 11.3 Insulation properties assumed for the dwelling different age bands

Age	Properties
Very Old	Solid wall construction (generally pre 1919). Flats of this age will be converted houses or tenements
Old	Cavity wall – mostly un-insulated (1919-1980)
Modern	Cavity wall – mostly insulated (post 1980)
New	Highly insulated, zero carbon standard homes

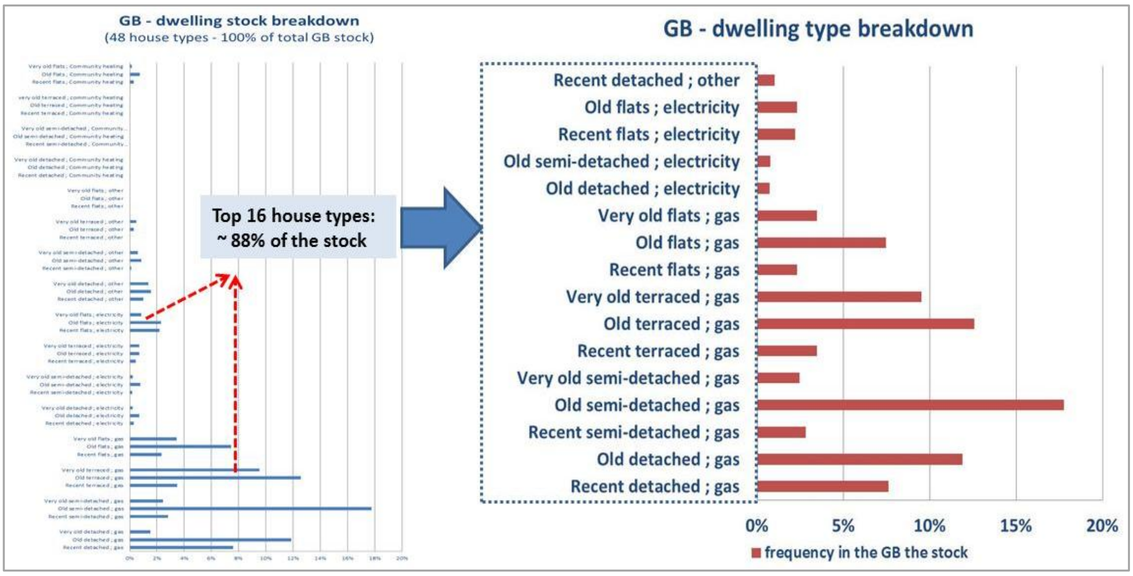


Figure 11.10 Selection of a representative sample of house types from a long-list of house types in the GB housing stock (Source: Element Energy)

[Note re Figure 11.10 - The population of minority house types that may be significant in certain areas, such as high-rise, off-gas or Economy 7, can be identified and captured as specific variants of the short-list.]

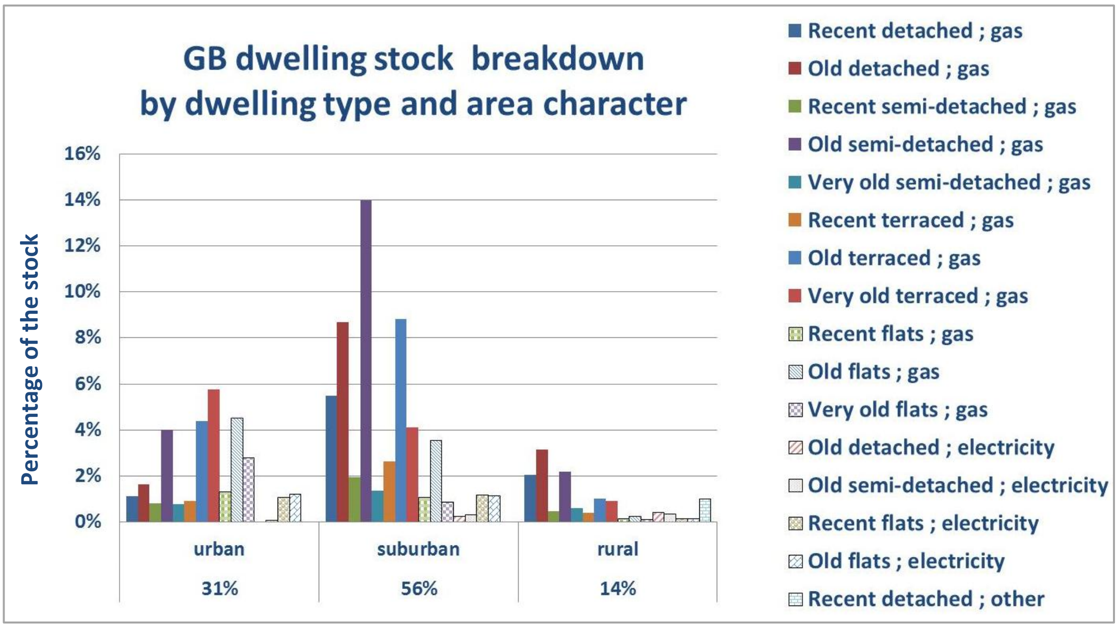


Figure 11.11 GB dwelling stock breakdown by dwelling type and area character (Source: Element Energy)

[Note re Figure 11.11 - The analysis of the House Condition Survey datasets provided an understanding of the typical mix of residential dwellings in the Rural, Suburban and residential areas. This information is used to identify which are the most typical dwellings served by Urban, Suburban and Rural LV feeders.]

Based on this analysis it was possible to populate the standard feeder loads with an appropriate mix of house types such that when aggregated together in the correct proportions (as defined by the relative frequencies of standard feeders in the overall feeder stock) the model reproduces the overall stock composition and the load experienced by the LV network.

This method enabled the model to closely reproduce the breakdown by house type, dwelling ages and heating fuel (electric/non-electric) across the different GB region and area characters (urban/suburban/rural) as observed in the House Condition Surveys (see, for example Figure 11.12 below).

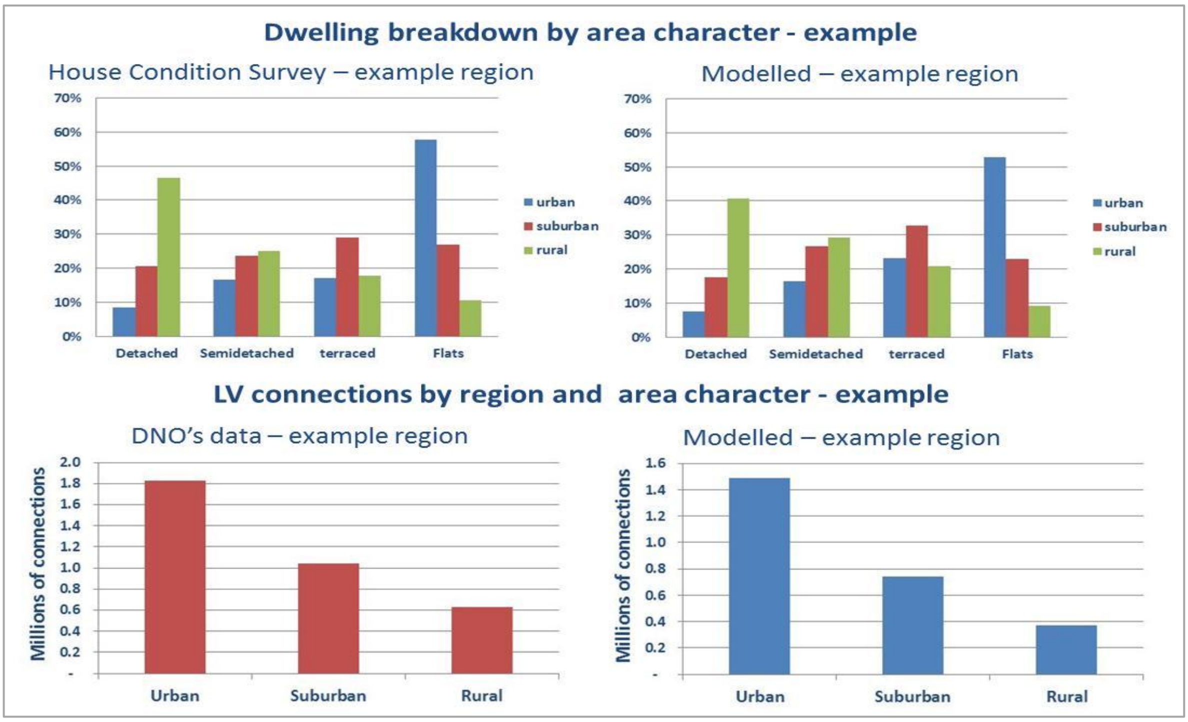


Figure 11.12 Dwelling breakdown by area character – example (Source: Element Energy)

[Note re Figure 11.12 - The coupling of the DNO information on LV feeder networks and the House Condition Survey enable a highly granular reproduction of both the characteristics of the regional building stock and LV network.]

11.1.4 Detailed analysis of the existing non-domestic building stock

An analysis was performed to characterise the non-domestic building stock in terms of premises type and floor space. The composition of the non-domestic building stock has been assessed on the basis of Valuation Office Agency data on the number of non-domestic premises and their rateable value. This data is available at local authority level and classifies the stock into an extensive range of sub-categories (nearly 40 categories). An estimate of the breakdown of the stock by floor space has been derived on the basis of rateable values.

The most prevalent non-domestic building types have been identified on the basis of floor space. For each local authority area the premises types have been ranked on the basis of their contribution to the overall non-domestic floor space. The premises types that are most commonly among the ten largest components of the overall stock have then been selected for detailed demand profile modeling. This short-list of premises types are then used as the building blocks of the standard feeder load configurations.

The short-list of non-domestic building types is as follows:

Table 11.4 Short-list of non-domestic premises types incorporated in the model

Non-domestic premises types
Small Retail (high street)
Large Retail (extended opening)
Office
Education
Hotel
Pubs/Clubs/Restaurants
Other/Industrial

The number of variations in the mix of non-domestic customers that could be connected to LV feeders is enormous and cannot be represented in a limited set of standard feeder types such that a representation of the overall stock can be reproduced when aggregated together. Instead, an average non-domestic customer has been developed for each region, which reflects the composition of the non-domestic stock in the region.

While the most prevalent premises types tended to be common between local authority areas, a significant variation in the mix of these premises types between local authority areas has been found. When averaging across a wider area, for example all local authorities in a Government Office Region, common patterns in the overall mix emerge. The average non-domestic building mix in local authority areas classified as rural, urban and suburban (based on government designations) is shown in the plot below.

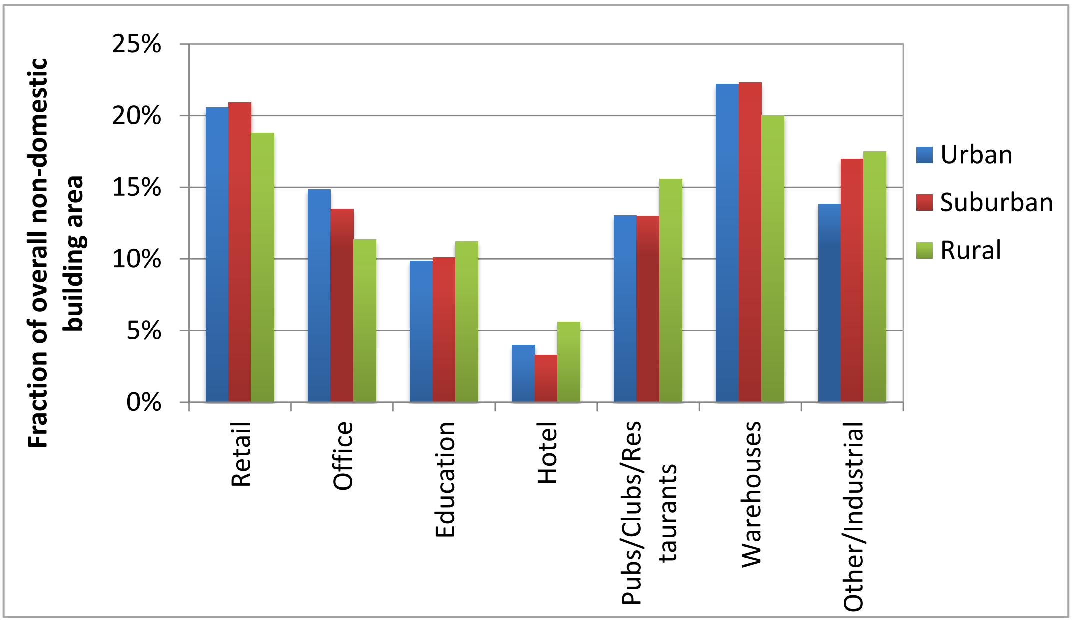


Figure 11.13 Average mix of non-domestic premises for local authority areas grouped by urban/rural character (Source: Element Energy)

The relative proportions of the premises types in the stock within each of the regions, together with the typical electricity consumption per unit area for the different premises types, are used to derive weighting factors to develop a weighted average non-domestic profile. The weighted average profile is based on a set of profiles for each individual premises type, which are each normalised by annual consumption. The non-domestic load on a particular feeder is then calculated on the basis of this normalised average profile scaled by the average consumption per connection on a feeder of that type (specific to each network type and varying by region) and the number of connections on the feeder (with appropriate diversity applied).

The average load per connection is be based on the estimated annual consumption (EAC) per LV feeder data provided by the DNOs and also data provided by Elexon on the distribution of electricity consumption per connection for each Profile Class within each Grid Supply Point (GSP) [52].

11.1.5 Modelling LV feeder load and load growth

The ultimate purpose of the LV network analysis was the identification of the basic building blocks - the standard feeder loads - enabling a bottom-up reproduction of existing and future network loading at a Low Voltage network level.

The analysis produced a set of standard feeders fully characterized in terms of:

1. Number of connections on the feeder (by region and area character)
2. Type of buildings served by the feeder (by region and area character)
3. Estimated Annual energy Consumption (EAC)
4. Relative frequency of the different feeder types across different GB regions and area character (urban/suburban/rural)

An example of this type highly-granular information is displayed in Table 11.5, below.

This information on the build-up of the LV network at feeder level can be combined with the modelling of electricity demand profiles for each of the basic building types in order to derive an assessment of load on the LV network.

This data on the composition of the building stock regionally and on each of the characteristic LV network types also provides the basis for forecasting how the load will evolve over time. This is due to new additions to the building stock, defined by a new build rate and rate of demolition of the existing stock (this is incorporated into the model both as addition of new feeders into the stock and as renewal of existing buildings with new build equivalents). The rate of penetration of new technologies, connected at LV level, is also a key determinant of future load growth. The LV network load configurations determined in this analysis enable the rate of load growth at feeder level to be forecast, based on higher level scenarios for the overall uptake of technologies at a national level.

[52] Based on: the EAC per LV feeder data provided by the DNOs and Elexon's data on the distribution of electricity consumption per connection for each Profile Class within each Grid Supply Point

Table 11.5 LV network loads for each region defined (Source: Element Energy)

	Scotland						North & Midlands						Wales						South & East						London					
LV network type	**Domestic**				**Non-dom**		**Domestic**				**Non-dom**		**Domestic**				**Non-dom**		**Domestic**				**Non-dom**		**Domestic**				**Non-dom**	
URBAN	**Detach**	**Semi**	**Terrace**	**Flat**	**NHH**	**HH**	**Detach**	**Semi**	**Terrace**	**Flat**	**NHH**	**HH**	**Detach**	**Semi**	**Terrace**	**Flat**	**NHH**	**HH**	**Detach**	**Semi**	**Terrace**	**Flat**	**NHH**	**HH**	**Detach**	**Semi**	**Terrace**	**Flat**	**NHH**	**HH**
Central business district	-	-	-	-	2.0	0.7	-	-	-	-	2.3	0.6	-	-	-	-	2.3	0.7	-	-	-	-	2.1	0.6	-	-	-	-	2.1	0.7
Dense urban (apartments etc) (H)	-	-	2.9	39.5	1.0	-	-	-	5.2	36.1	0.8	-	-	-	5.9	35.1	0.7	-	-	-	4.3	37.5	0.9	-	-	-	3.2	38.7	0.9	-
Town centre	-	-	1.3	4.9	2.1	0.6	-	-	0.7	2.0	2.3	0.6	-	-	1.1	3.2	2.3	0.6	-	-	1.2	3.7	2.1	0.5	-	-	1.0	3.6	2.2	0.6
Business park (M)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Retail park (M)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Suburban street (3/4b detached / semis	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
New build housing estate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Terraced Street	5.7	12.4	16.0	15.2	2.0	-	5.3	12.1	21.8	6.7	1.6	-	6.4	16.0	18.9	4.6	1.6	-	6.0	9.6	20.0	9.3	1.6	-	2.1	7.4	22.2	17.3	1.9	-
Rural village (overhead)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Rural village (underground)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Rural farmstead / small holdings	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
SUBURBAN																														
Central business district	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dense urban (apartments etc) (H)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Town centre	-	-	-	-	2.5	0.4	-	-	-	-	2.5	0.5	-	-	-	-	2.3	0.6	-	-	-	-	2.5	0.4	-	-	-	-	2.4	0.5
Business park (M)	-	-	-	-	2.5	0.4	-	-	-	-	2.5	0.5	-	-	-	-	2.3	0.6	-	-	-	-	2.5	0.4	-	-	-	-	2.4	0.5
Retail park (M)	-	-	-	-	2.5	0.4	-	-	-	-	2.5	0.5	-	-	-	-	2.3	0.6	-	-	-	-	2.5	0.4	-	-	-	-	2.4	0.5
Suburban street (3/4b detached / semis	10.2	17.7	4.8	-	2.2	-	10.1	18.4	4.0	-	2.2	-	9.7	19.3	4.9	-	2.3	-	11.7	15.7	3.5	-	2.0	-	6.7	20.1	6.5	-	2.2	-
New build housing estate	10.0	14.9	0.9	7.3	1.0	-	11.3	18.0	0.8	2.3	1.0	-	11.3	19.3	0.9	2.3	1.1	-	12.5	14.7	0.9	2.9	0.9	-	6.6	16.2	1.1	10.1	1.0	-
Terraced Street	-	1.5	17.4	13.8	1.6	-	-	2.6	21.0	9.4	1.7	-	-	2.7	23.7	7.7	1.8	-	-	1.8	18.3	11.8	1.5	-	-	1.6	18.2	13.3	1.7	-
Rural village (overhead)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Rural village (underground)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Rural farmstead / small holdings	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RURAL																														
Central business district	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dense urban (apartments etc) (H)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Town centre	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Business park (M)	-	-	-	-	2.5	0.3	-	-	-	-	2.5	0.4	-	-	-	-	2.2	0.6	-	-	-	-	2.6	0.3	-	-	-	-	2.5	0.4
Retail park (M)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Suburban street (3/4b detached / semis	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
New build housing estate	15.4	10.8	0.5	1.0	3.5	-	17.1	9.9	0.4	0.2	3.6	-	17.6	9.8	0.4	0.2	3.5	-	17.1	9.7	0.3	0.3	3.7	-	16.6	10.0	0.3	0.9	3.6	-
Terraced Street	-	2.9	11.7	10.3	2.2	-	-	4.2	14.3	6.3	2.3	-	-	4.8	15.2	4.9	2.3	-	-	3.8	12.8	8.3	2.3	-	-	3.2	10.0	11.7	2.3	-
Rural village (overhead)	7.3	6.7	0.8	-	0.9	-	8.1	6.2	0.6	-	1.0	-	8.7	6.3	0.6	-	1.1	-	8.0	6.2	0.6	-	1.0	-	8.2	6.4	0.6	-	1.0	-
Rural village (underground)	13.9	12.4	3.6	1.1	2.6	-	16.2	11.3	2.6	0.6	2.4	-	17.4	11.2	2.3	0.5	2.3	-	16.1	11.1	2.5	0.6	2.4	-	16.1	11.4	2.3	0.7	2.3	-
Rural farmstead / small holdings	11.0	-	-	-	-	-	11.0	-	-	-	-	-	11.0	-	-	-	-	-	11.0	-	-	-	-	-	11.0	-	-	-	-	-

[Note re Table 11.5 - that the number of connections represents an average for that LV network type, hence the non-integer connection numbers.]

11.2 Electric vehicles – further assumptions

In order to model the impact of electric vehicles (EV) on the electric loading at a low voltage network level, the modelling exercise included a number of assumptions on:

1. Total number of electric vehicles in the national vehicle stock (national uptake scenarios)
2. Average daily mileages and vehicle efficiency – used to generate annual charging demand (TWh/year)
3. Percentage of the EV charging at home or in other locations (i.e. at work or on the street);
4. Number of electric vehicle by GB region
5. Realistic charging profiles for electric vehicles charging at home or in other locations (MWh per hour over a typical weekday)

The scenarios for electric vehicle uptake at a GB level have been taken from the Department for Transport (DfT) strategy for delivery of the fourth Carbon Budget (Autumn 2011).

The assumptions used to derive forecasts for the total electricity demand and the assumptions regarding the percentage of EVs that charge in different locations, have been taken from the same source. These assumptions are reported in turn below.

The disaggregation of electric vehicle numbers to the regional level and development of charging profiles has been based on additional modelling, also discussed below.

11.2.1 Total energy demand

The total energy demand figures supplied by the DfT datasets assume battery specifications for the vehicles as reported in the table below, and a split between rapid, fast and slow charging speeds. The charging speeds are defined as follows:

- Rapid charging: 50kW draw-down rate;
- Fast charging: 7kW draw-down rate;
- Slow charging: 3kW draw-down rate.

Table 11.6 Battery size assumption underlying the Department for Transport (DfT) as part of its autumn 2011 strategy (Source: Element Energy)

	Car			Van	
	EV	PHEV	REEV	EV	PHEV
Battery Size (kWh)	22	5	13	36	7

NB: These are averages across segments; we would expect smaller battery packs for smaller segments and vice versa; as the market develops with EV penetration spreading from smaller to larger vehicles we would expect the average to increase over time. These figures are more representative of this mature market.

[Note re Table 11.6 - (EV = Battery electric vehicles, PHEV = Plug-in hybrid electric vehicles and REEV = Range extender electric vehicles.]

The key characteristic of the DfT scenarios is the predominance of fast and rapid charging by 2020, with no more slow charging customers beyond 2030. This is reproduced in Figure 11.14, below, which incorporates fast and rapid charging into a single trend-line (named 'fast').

The DfT commentary reports that although there is uncertainty on future recharging behaviour, the figures provided are based on the best available assumptions on the distance travelled, likely electric range of different type of vehicle (EV, PHEV or REEEV), the ownership of the vehicles (private, company or fleet), the proportion of households with off-street parking and the impact of increasing battery range on the need for on-street recharging, among other assumptions.

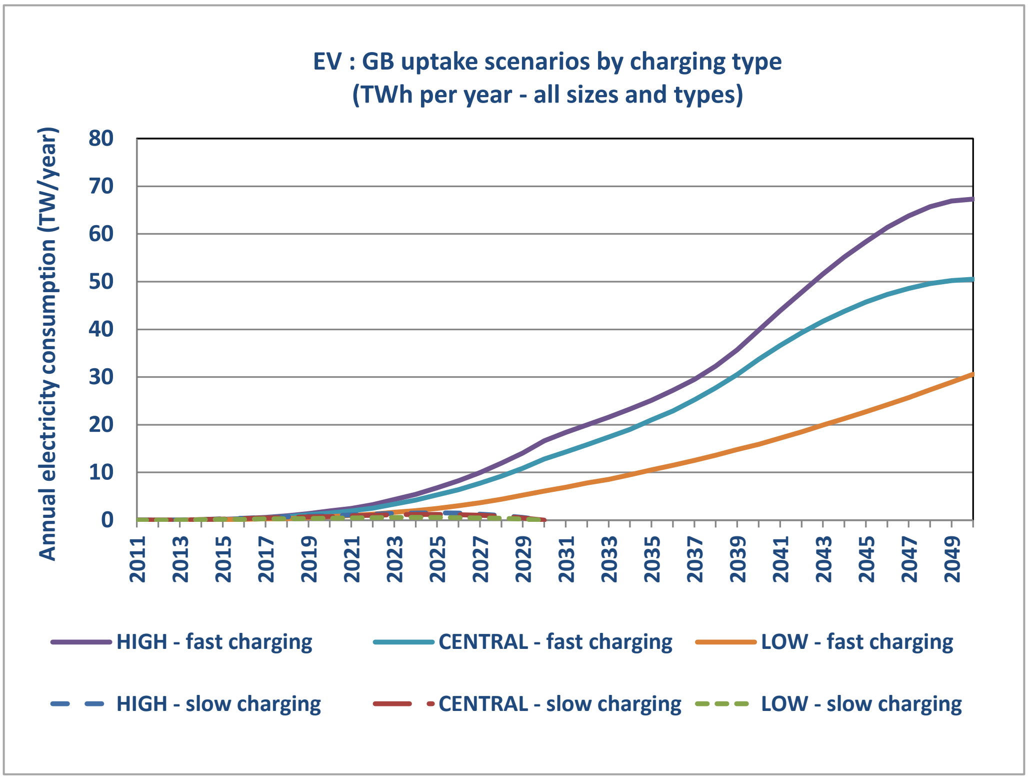


Figure 11.14 **Cumulative electricity demand generated by all electric vehicles over time as described by the Department for Transport (DfT) scenarios (Source: Element Energy)**

11.2.2 Recharging locations

The Department of Transport figures describing the percentage of electric vehicle recharging in different charging locations are reported in Figure 11.15 below.

As for the energy consumption figures, the DfT commentary states that recharging behaviours are highly uncertain and could therefore be used as a variable for sensitivities.

The figures reported, however, are based on the *OLEV Infrastructure Strategy*[53] expectation that the great majority of recharging will be undertaken at home (i.e. overnight), although it is uncertain to what extent future consumers might use public infrastructure to do this.

[53] Make the Connection: The Plug-In Vehicle Infrastructure Strategy, Office for Low Emission Vehicles, June 2011.

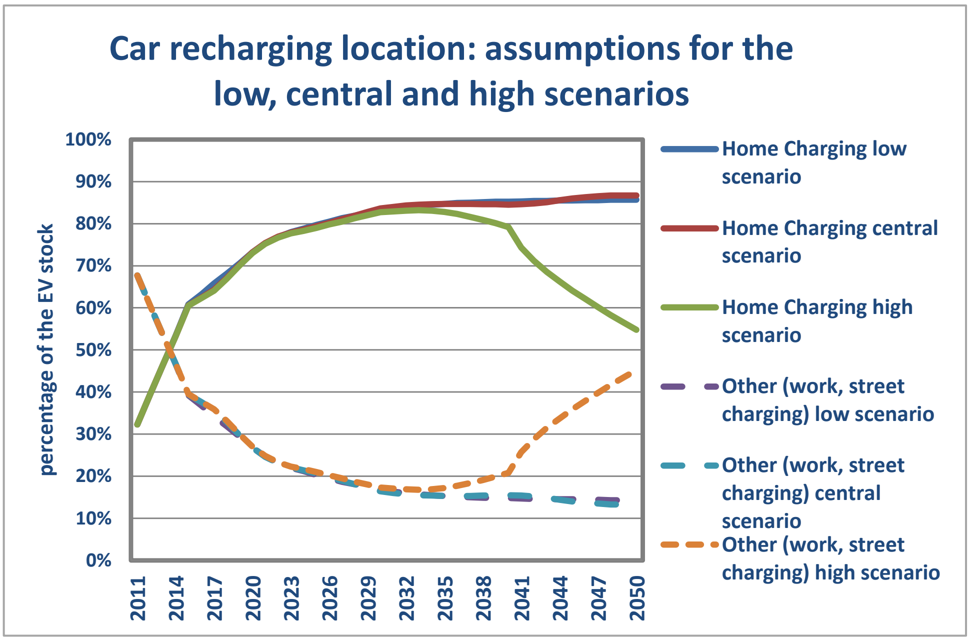


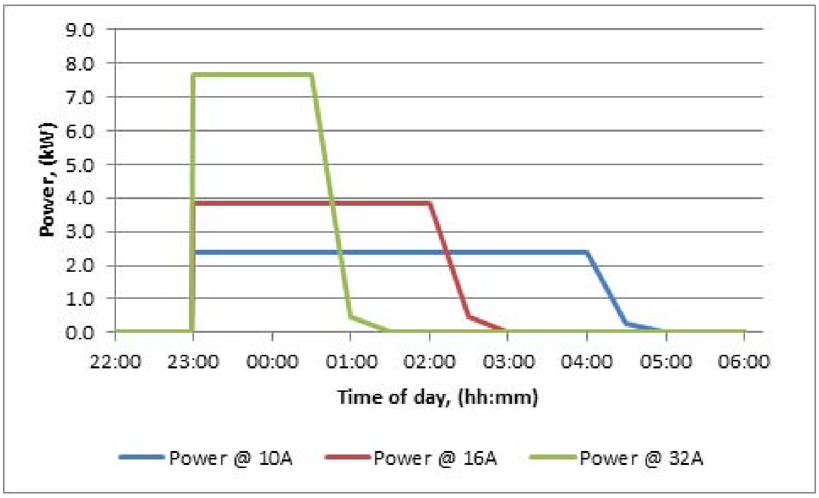
Figure 11.15 Percentage of the electric vehicles charging in different recharging locations (Source: Element Energy - as described by the Department for Transport (DfT) scenarios)

11.2.3 EV charging profiles

The data used for both the WS2 and WS3 models has been based on the TSB's, Ultra-Low Carbon Vehicles Demonstrator Programme, Initial Findings, 2011[54]. NB. This is only the initial findings, as the full report is still to be published. Within this TSB trial:

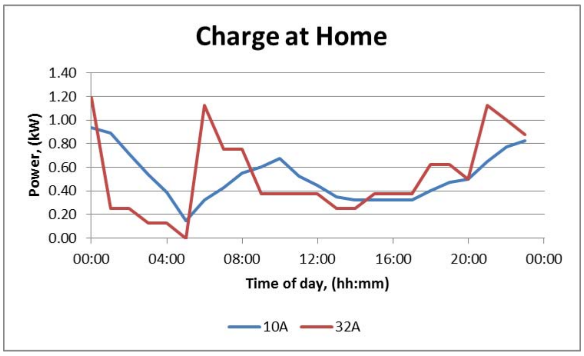
1. It is based on real trial data using
    a. 8 consortia running projects
    b. Including 19 vehicle manufacturers
    c. 340 vehicles (electric, pure hybrid and fuel cell vehicles).
    d. 110,389 individual journeys (from December 2009 to June 2011)
    e. 677,209 miles travelled (1,089,862 km)
    f. 19,782 charging events
    g. 143.2 MWh of electricity consumed
2. It does not have definitive breakdown of charging cycles, but it has been possible to reverse engineer the results in the report to ascertain the likely diversified load presented to the distribution network
3. The scenarios from DECC are disaggregated by charging method and location, it is therefore necessary to derive profiles on this basis
    a. Two charging types are assumed: 10A @ 240V and 32A @ 240V. For a full charge (flat battery) of a single vehicle, this would equate to either 10A or 32A for a defined period of time (2hrs and 5hrs) as shown in the graph below. Our analysis considers the residual charge left in the battery, which will effectively reduce the charging time, but not the peak current drawn from the network

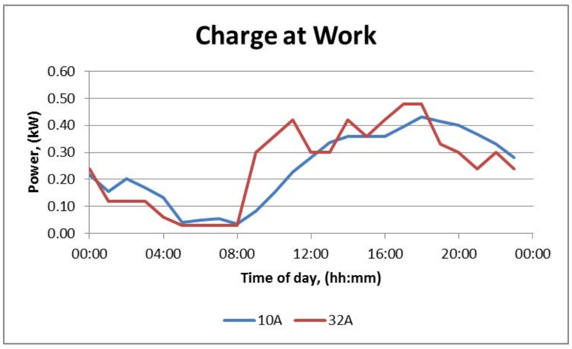
[54] TSB, Ultra-Low Carbon Vehicles Demonstrator Programme, Initial Findings, 2011: http://www.innovateuk.org/_assets/pdf/press-releases/ulcv_reportaug11.pdf



b. The number of miles driven between charges is directly proportional to the amount of kWh required to top-up the battery. This has been based on Vauxhall Ampera data of a 16kWh battery giving 40miles of pure electric driving
c. Average mileage per day is shown on page 8 of the document under "Distribution of daily mileage by ownership" as being c25miles for both private and fleet users. We have halved the number of miles between charges for fleet users, on the assumption that they can charge at both home and work
d. The time of charge is taken from Page 10 of the TSB report (chart titled "Start time frequency by ownership"). Whilst this data looks counter-intuitive (peak at midnight) it is based on best available trial data (NB. The report does not reference any specific charging tariffs that may be used to promote this behaviour)
e. Energy, by way of the time taken to charge (not the peak current) has been apportioned according to the time required for a full EV charge (3b), the energy required for that daily distance (3c), and the proportion of users who charge at different times of the day (3d)
f. We assume that every car drives the average daily distance, every day, and that they charge on a daily basis. This is clearly an approximation, and does not factor in behavioural changes of drivers

4. Results are shown below:





5. These two graphs are collated to form the figure below

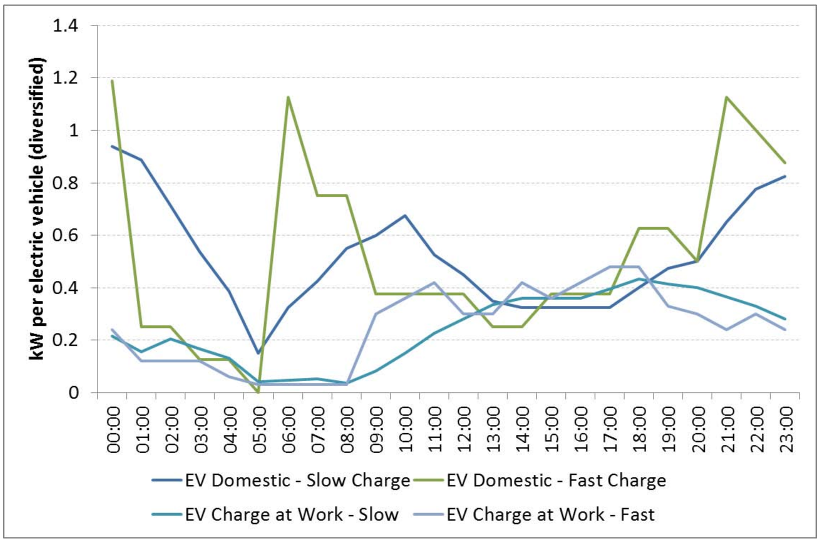


Figure 11.16 Combined Graph showing diversified EV charging profiles

11.2.4 Electric vehicles by region

The Department of Transport national uptake scenarios do not distinguish among the different GB regions. The geographical disaggregation of the national figures has been based on a two-stage approach, which can be summarised as follows (please refer to Section 3.2.7 for further information):

- Step 1: the country has been divided into a number of regions (five regions in total), such that any regional differences that might drive differences in the rate of uptake of technologies can be taken into account (i.e. car stock dimension, extent of urbanisation, etc.)
- Step 2: a further analysis is undertaken to predict how national EV sales figure may be disaggregated across the regions by combining regional variations (step 1) with detailed models of consumer behaviour. These consumer behaviour models take a bottom-up approach to understanding the relative likelihood of different types of consumers to take-up different technologies, depending on a range of factors that influence their purchasing decisions.

The consumer uptake modelling is based on data on vehicle purchasing preferences captured through a survey of over 3,000 private vehicle purchasers. This informed a segregation of consumers into a number of groups (such as early adopters, mass market purchasers, laggards) within each of the regions, which could be combined with data on the total car park in each region and split between private and company ownership, to inform the regional disaggregation. The results of this regional disaggregation are presented in Figure 11.16, below, on the basis of the percentage of the total GB electric vehicle stock within each region over time.

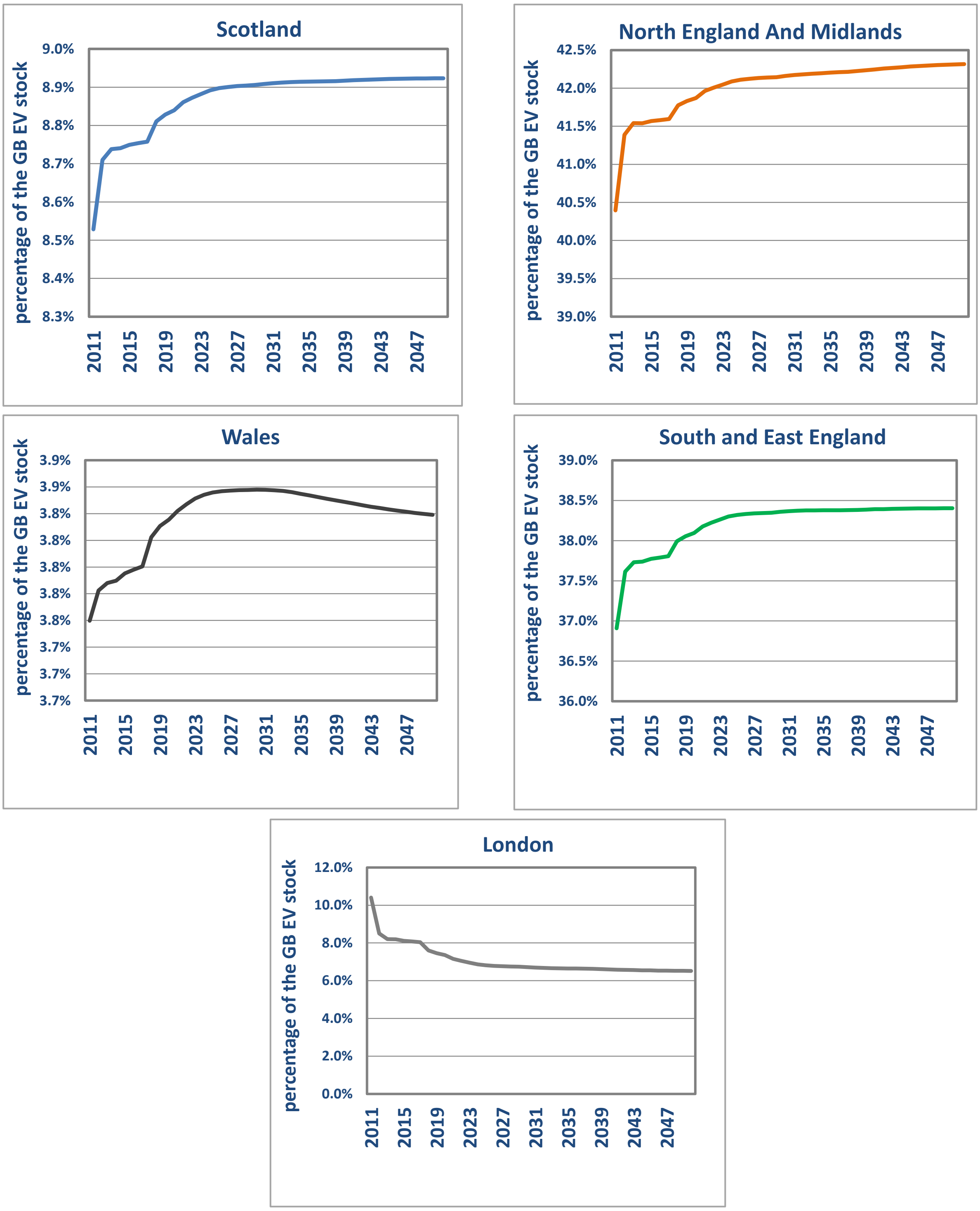


Figure 11.17 Relative uptake of electric vehicles in the five GB regions modelled (Source: Element Energy)

[Note re Figure 11.16 - The figures are derived from a two-step approach aimed at disaggregating the DfT national uptake scenarios according to 1) relevant geographical difference and 2) specific consumer behaviour considerations.]

11.3 HV network analysis

The feeder parameters at HV were determined primarily through extensive analysis of DNO data. The DNOs provided information from the IIS return submitted to Ofgem, which includes information on all HV feeders throughout the network. This information includes the total length of the feeder and the number of customers connected, together with the "class" into which this feeder falls.

The classes of feeder are defined in Table 11.7 below.

Table 11.7 Standard HV feeder definitions from IIS return (Source: DNOs / Ofgem)

Circuit Type	%OHL		Circuit Length		Number of Connected Customers
UG1A	0%		< 4 km		< 1000
UG1B	0%		< 4 km		> 1000
UG2A	0%		> 4 km		< 2000
UG2B	0%		> 4 km		> 2000
MA1A	> 0%	< 20%	< 8 Km		< 1000
MA1B	> 0%	< 20%	< 8 Km		> 1000
MA2A	> 0%	< 20%	> 8km		< 2500
MA2B	> 0%	< 20%	> 8km		> 2500
MB1A	> 20%	< 50%	< 11 km		< 1000
MB1B	> 20%	< 50%	< 11 km		> 1000
MB2A	> 20%	< 50%	> 11 km		< 2200
MB2B	> 20%	< 50%	> 11 km		> 2200
MC1A	> 50%	< 80%	< 19 km		< 500
MC1B	> 50%	< 80%	< 19 km		> 500
MC2A	> 50%	< 80%	> 19 km		< 1700
MC2B	> 50%	< 80%	> 19 km		> 1700
OH1A	> 80%		< 40 km		< 400
OH1B	> 80%		< 40 km		> 400
OH2A	> 80%		> 40 km	< 55 km	< 700
OH2B	> 80%		> 40 km	< 55 km	>700
OH3A	> 80%		> 55 km		< 700
OH3B	> 80%		> 55 km		> 700

The data from all DNOs was compiled into spreadsheet format and the feeders were then ordered according to their customer density. An assumption then had to be taken regarding when the customer density indicated a transition from "urban" to "suburban" network type, and likewise from "suburban" to "rural". This was done by calculating the total number of customers supplied and apportioning based on previous knowledge and experience, which suggested that approximately 45% of customers are within urban areas, 47% in suburban areas and the remaining 8% in rural areas.

Having defined these boundaries, it was then possible to classify each feeder as being located in either an urban, suburban or rural setting. This was cross-checked by examining which of the 22 feeder types described in Table 11.7 above were found in each of the three areas. Clearly, any overhead feeders in an urban environment were deemed to be anomalous, for example.

The average feeder length in each case could then be determined. In order to calculate this, networks were split into "radial" and "meshed" types as these exhibit different characteristics. A sample of feeders was then examined at all voltages to determine the "branching" factor that should be applied. The lengths defined here are the total electrical feeding lengths and hence needed to be scaled down to determine the main feeder length.

A summary of the final parameters for each of the seven HV feeder types is contained in Table 11.8.

Table 11.8 Standard HV feeder parameters

Network	Geographical Area	Customer Density	Network Construction	Topology	Total length (km)	Branched factor	Main length (km)
HV 1	Urban	High	Underground	Radial	4.23	0.9	**3.8**
HV 2	Urban	High	Underground	Meshed	2.79	0.9	**2.5**
HV 3	Suburban	Medium	Underground	Radial	4.62	0.8	**3.7**
HV 4	Suburban	Medium	Underground	Meshed	2.70	0.8	**2.2**
HV 5	Suburban	Medium	Mixed	Radial	15.04	0.7	**10.5**
HV 6	Rural	Low	Overhead	Radial	40.60	0.46	**18.7**
HV 7	Rural	Low	Mixed	Radial	18.00	0.55	**9.9**

The ratings of these feeders were then determined by analysing a sub-set of DNO data (where provided) to determine the average conductor size used in each of these cases (urban, suburban and rural settings etc.). Some discussions were held with DNOs and the outcome of these was combined with the knowledge and experience of EA Technology to determine the appropriate number of distribution substations fed by each HV circuit, and the size of transformer at that distribution substation in each case.

Loads are then apportioned to the HV feeders by summing the LV loads associated with each feeder type (and the propensity with which these feeders are connected). An amount of HV commercial and industrial load is then added in and apportioned across feeders. The load data has been based on analysis of DUKES and from knowledge and experience of EA Technology staff to make engineering judgements. HV connected generation is apportioned in a similar way, split by wind generation and other generation.

11.4 EHV network analysis

Analysis was carried out of DNO Long Term Development Statements and through modelling various sample networks that were provided by DNOs as being representative of each of the six EHV feeder types. From this analysis, the EHV parameters were defined, as shown in the table below.

Table 11.9 Standard EHV feeder parameters

Network	Geographical Area	Customer Density	Network Construction	Topology	Total length (km)	Branched factor	Main length (km)
EHV 1	Urban	High	Underground	Radial	2.63	1	**2.63**
EHV 2	Urban	High	Underground	Meshed	2.76	1	**2.76**
EHV 3	Suburban	Medium	Mixed	Radial	4.27	1	**4.27**
EHV 4	Suburban	Medium	Mixed	Meshed	3.86	1	**3.86**
EHV 5	Rural	Low	Overhead	Radial	9.54	1	**9.54**
EHV 6	Rural	Low	Mixed	Radial	9.08	1	**9.08**

As described earlier, the feeder mapping exercise was carried out to determine which HV feeders are supplied by which EHV circuits. In this way, and by reconciling the total number of HV and EHV feeders with the numbers obtained from IIS and LTDS data respectively, the number of each type of HV feeder supplied by each EHV feeder was determined.

The load at EHV is then calculated by summing the load on the appropriate HV feeders. In addition, similarly to the process at HV, the relevant EHV industrial load is also provided, as is the mix of EHV connected generation, which is apportioned according to engineering judgement for wind and other generation. The data for load and generation at EHV is again taken from DUKES.

11.5 GB Network Model Base Case Data

Table 11.10 EHV circuits by volume and proportion

Apportionment of EHV Feeders - GB Base Case	Numbers	%
EHV1 Urban Underground Radial	540	7%
EHV2 Urban Underground Meshed	810	11%
EHV3 Suburban Mixed Radial	720	10%
EHV4 Suburban Mixed Meshed	1,680	22%
EHV5 Rural Overhead Radial	3,000	40%
EHV6 Rural Mixed Radial	750	10%
	7,500	100%

Table 11.11 HV circuits by volume and proportion

Apportionment of HV Feeders - GB Base Case	Numbers	%
HV1 Urban Underground Radial	5,643	18%
HV2 Urban Underground Meshed	2,997	9%
HV3 Suburban Underground Radial	3,120	10%
HV4 Suburban Underground Meshed	4,200	13%
HV5 Suburban Mixed Radial	5,760	18%
HV6 Rural Overhead Radial	6,750	21%
HV7 Rural Mixed Radial	3,450	11%
	31,920	100%

Table 11.12 LV circuits by volume and proportion

Apportionment of LV Feeders - GB Base Case	Numbers	%
LV1 Central Business District	16,246	1.7%
LV2 Dense urban (apartments etc)	50,099	5.2%
LV3 Town centre	32,154	3.3%
LV4 Business park	70,119	7.3%
LV5 Retail park	13,502	1.4%
LV6 Suburban street (3 4 bed semi detached or detached houses)	122,765	12.7%
LV7 New build housing estate	149,493	15.5%
LV8 Terraced street	336,922	34.9%
LV9 Rural village (overhead construction)	24,122	2.5%
LV10 Rural village (underground construction)	24,802	2.6%
LV11 Rural farmsteads small holdings	4,993	0.5%
LV12 Meshed Central Business District	6,179	0.6%
LV13 Meshed Dense urban (apartments etc)	13,284	1.4%
LV14 Meshed Town centre	11,677	1.2%
LV15 Meshed Business park	12,096	1.3%
LV16 Meshed Retail park	2,520	0.3%
LV17 Meshed Suburban street (3 4 bed semi detached or detached houses)	26,208	2.7%
LV18 Meshed New build housing estate	5,040	0.5%
LV19 Meshed Terraced street	44,482	4.6%
	966,702	100%

Table 11.13 Starting load position for all feeder types in GB model

	Starting Load (kW)
EHV1 Urban Underground Radial	19706
EHV2 Urban Underground Meshed	14630
EHV3 Suburban Mixed Radial	4656
EHV4 Suburban Mixed Meshed	6787
EHV5 Rural Overhead Radial	3820
EHV6 Rural Mixed Radial	4997
HV1 Urban Underground Radial	2999
HV2 Urban Underground Meshed	1933
HV3 Suburban Underground Radial	1381
HV4 Suburban Underground Meshed	1612
HV5 Suburban Mixed Radial	1037
HV6 Rural Overhead Radial	1461
HV7 Rural Mixed Radial	1282
LV1 Central Business District	210
LV2 Dense urban (apartments etc)	60
LV3 Town centre	170
LV4 Business park	119
LV5 Retail park	144
LV6 Suburban street (3 4 bed semi detached or detached houses)	47
LV7 New build housing estate	40
LV8 Terraced street	58
LV9 Rural village (overhead construction)	26
LV10 Rural village (underground construction)	51
LV11 Rural farmsteads small holdings	17
LV12 Meshed Central Business District	210
LV13 Meshed Dense urban (apartments etc)	60
LV14 Meshed Town centre	170
LV15 Meshed Business park	119
LV16 Meshed Retail park	144
LV17 Meshed Suburban street (3 4 bed semi detached or detached houses)	47
LV18 Meshed New build housing estate	40
LV19 Meshed Terraced street	58

Table 11.14 Overview of the feeder thermal starting parameters as taken from the model (N.B. The trigger levels for each circuit type under the default assumptions are shown in the last two columns highlighted in purple)

	Substation capacity	Size Of Tx	Average No Feeders Sharing Tx	Thermal Tx(kW)	Thermal Cable (kW)	Phase Imbalance Cables	Phase Imbalance Tx	Substation Intervention Threshold	Cable Intervention Threshold	Thermal Tx (kW)	Thermal Cable (kW)
EHV1 Urban Underground Radial	180000	83400	1	83400	41700	1	1	50%	60%	83,400	25,020
EHV2 Urban Underground Meshed	60000	48000	1	48000	24000	1	1	75%	75%	36,000	18,000
EHV3 Suburban Mixed Radial	120000	74200	1	74200	37100	1	1	50%	60%	74,200	22,260
EHV4 Suburban Mixed Meshed	60000	48000	1	48000	24000	1	1	75%	75%	36,000	18,000
EHV5 Rural Overhead Radial	60000	50800	1	50800	25400	1	1	80%	60%	50,800	15,240
EHV6 Rural Mixed Radial	60000	53800	1	53800	26900	1	1	80%	60%	53,800	16,140
EHV7		1000	1	1000	3000	1	1	50%	50%	500	1,500
EHV8		1000	1	1000	3000	1	1	50%	50%	500	1,500
HV1 Urban Underground Radial	64000	32000	8	4000	6756	1	1	50%	67%	4,000	4,504
HV2 Urban Underground Meshed	10000	10000	3	3333	5709	1	1	75%	80%	2,500	4,567
HV3 Suburban Underground Radial	48000	24000	7	3429	5328	1	1	50%	67%	3,429	3,552
HV4 Suburban Underground Meshed	10000	10000	4	2500	3901	1	1	75%	80%	1,875	3,121
HV5 Suburban Mixed Radial	48000	24000	4	6000	5100	1	1	50%	67%	6,000	3,400
HV6 Rural Overhead Radial	12000	12000	4	3000	3711	1	1	80%	67%	3,000	2,474
HV7 Rural Mixed Radial	12000	12000	4	3000	4567	1	1	80%	67%	3,000	3,045
HV8		1000	1	1000	3000	1	1	67%	67%	667	2,000
LV1 Central Business District	1000	1000	4	250	257	0.9	0.95	100%	100%	238	231
LV2 Dense urban (apartments etc)	800	800	4	200	205	0.9	0.95	100%	100%	190	184
LV3 Town centre	1000	1000	5	200	199	0.9	0.95	100%	100%	190	179
LV4 Business park	1000	1000	4	250	205	0.9	0.95	100%	100%	238	184
LV5 Retail park	1000	1000	4	250	205	0.9	0.95	100%	100%	238	184
LV6 Suburban street (3/4b semi)	500	500	4	125	139	0.9	0.95	100%	100%	119	125
LV7 New build housing estate	500	500	4	125	205	0.9	0.95	100%	100%	119	184
LV8 Terraced street	500	500	4	125	139	0.9	0.95	100%	100%	119	125
LV9 Rural village (overhead construction)	100	100	2	50	163	0.9	0.95	100%	100%	48	147
LV10 Rural village (underground construction)	315	315	3	105	141	0.9	0.95	100%	100%	100	127
LV11 Rural farmsteads small holdings	50	50	1	50	70	0.9	0.95	100%	100%	48	63
LV12 Meshed Central Business District	2000	2000	5	400	398	0.9	0.95	100%	100%	380	359
LV13 Meshed Dense urban (apartments etc)	1000	1000	5	200	410	0.9	0.95	100%	100%	190	369
LV14 Meshed Town centre	1000	1000	5	200	398	0.9	0.95	100%	100%	190	359
LV15 Meshed Business park	1000	1000	5	200	410	0.9	0.95	100%	100%	190	369
LV16 Meshed Retail park	1000	1000	5	200	410	0.9	0.95	100%	100%	190	369
LV17 Meshed Suburban street (3/4b semi)	1000	1000	5	200	283	0.9	0.95	100%	100%	190	255
LV18 Meshed New build housing estate	1000	1000	5	200	283	0.9	0.95	100%	100%	190	255
LV19 Meshed Terraced street	1000	1000	5	200	480	0.9	0.95	100%	100%	190	432
LV20		1000	1	1000	72	0.9	0.95	100%	100%	950	65

Table 11.15 Overview of the feeder fault level and voltage starting parameters as taken from the model (N.B. The two columns on the right show the maximum amount of load (generation) that can be connected before the legroom (headroom) is breached)

	Fault Level Parameters		Voltage Parameters				
	Starting Fault Level	Fault Level Headroom	Voltage Headroom	Voltage Legroom	kW/%	Permitted kW prior to Voltage Headroom Breach	Permitted kW prior to Voltage Legroom Breach
EHV1 Urban Underground Radial	562.5	750	6%	6%	19,300	115,800	115,800
EHV2 Urban Underground Meshed	712.5	750	6%	6%	18,000	108,000	108,000
EHV3 Suburban Mixed Radial	487.5	750	6%	6%	7,700	46,200	46,200
EHV4 Suburban Mixed Meshed	637.5	750	6%	6%	8,600	51,600	51,600
EHV5 Rural Overhead Radial	262.5	750	6%	6%	18,000	108,000	108,000
EHV6 Rural Mixed Radial	300	750	6%	6%	12,500	75,000	75,000
EHV7	637.5	750	6%	6%	3,000	18,000	18,000
EHV8	637.5	750	6%	6%	3,000	18,000	18,000
HV1 Urban Underground Radial	187.5	250	6%	6%	6,100	36,600	36,600
HV2 Urban Underground Meshed	200	250	6%	6%	5,200	31,200	31,200
HV3 Suburban Underground Radial	150	250	6%	6%	3,900	23,400	23,400
HV4 Suburban Underground Meshed	187.5	250	6%	6%	3,300	19,800	19,800
HV5 Suburban Mixed Radial	150	250	6%	6%	440	2,640	2,640
HV6 Rural Overhead Radial	75	250	6%	6%	280	1,680	1,680
HV7 Rural Mixed Radial	87.5	250	6%	6%	800	4,800	4,800
HV8	165	250	6%	6%	300	1,800	1,800
LV1 Central Business District	5	25	1%	15%	40	40	600
LV2 Dense urban (apartments etc)	4.25	25	1%	15%	40	40	600
LV3 Town centre	5	25	1%	15%	40	40	600
LV4 Business park	5	25	1%	15%	40	40	600
LV5 Retail park	5	25	1%	15%	40	40	600
LV6 Suburban street (3 4 bed semi detached or detached houses)	3.75	25	1%	15%	40	40	600
LV7 New build housing estate	3.75	25	1%	15%	40	40	600
LV8 Terraced street	3.75	25	1%	15%	40	40	600
LV9 Rural village (overhead construction)	3	25	1%	15%	40	40	600
LV10 Rural village (underground construction)	3	25	1%	15%	40	40	600
LV11 Rural farmsteads small holdings	2.5	25	1%	15%	40	40	600
LV12 Meshed Central Business District	8.75	25	1%	15%	40	40	600
LV13 Meshed Dense urban (apartments etc)	7.5	25	1%	15%	40	40	600
LV14 Meshed Town centre	8.75	25	1%	15%	40	40	600
LV15 Meshed Business park	10	25	1%	15%	40	40	600
LV16 Meshed Retail park	10	25	1%	15%	40	40	600
LV17 Meshed Suburban street (3 4 bed semi detached or detached houses)	7.5	25	1%	15%	40	40	600
LV18 Meshed New build housing estate	7.5	25	1%	15%	40	40	600
LV19 Meshed Terraced street	7.5	25	1%	15%	40	40	600
LV20	10	25	1%	15%	40	40	600

12 Appendix C: Customer Load Analysis

12.1 Building loads

The WS3 model requires estimates of half hourly demand profiles for the 19 different LV feeder types. These are built up from a set of individual point loads for 25 different building types (17 domestic building types and 8 non-domestic types) plus non-building related loads (street lighting, traffic lights, signage etc.). Demand profiles at this high level of granularity are required for a number of reasons as follows

- The demand profile varies significantly between building types, depending on factors such as size, age, construction, building use and occupancy
- Different buildings have different potential for uptake of LCTs
- Different potential for DSR in each building type due to the different appliance populations

Figure 12.1 is an overview of the process for estimating LV feeder demand profiles. Individual profiles for each point load type are aggregated based on the number of each point load type present on each feeder. For different years of the scenario, the individual point load profiles will vary depending on the uptake of LCTs. The makeup of the feeders will also vary as new buildings are added.

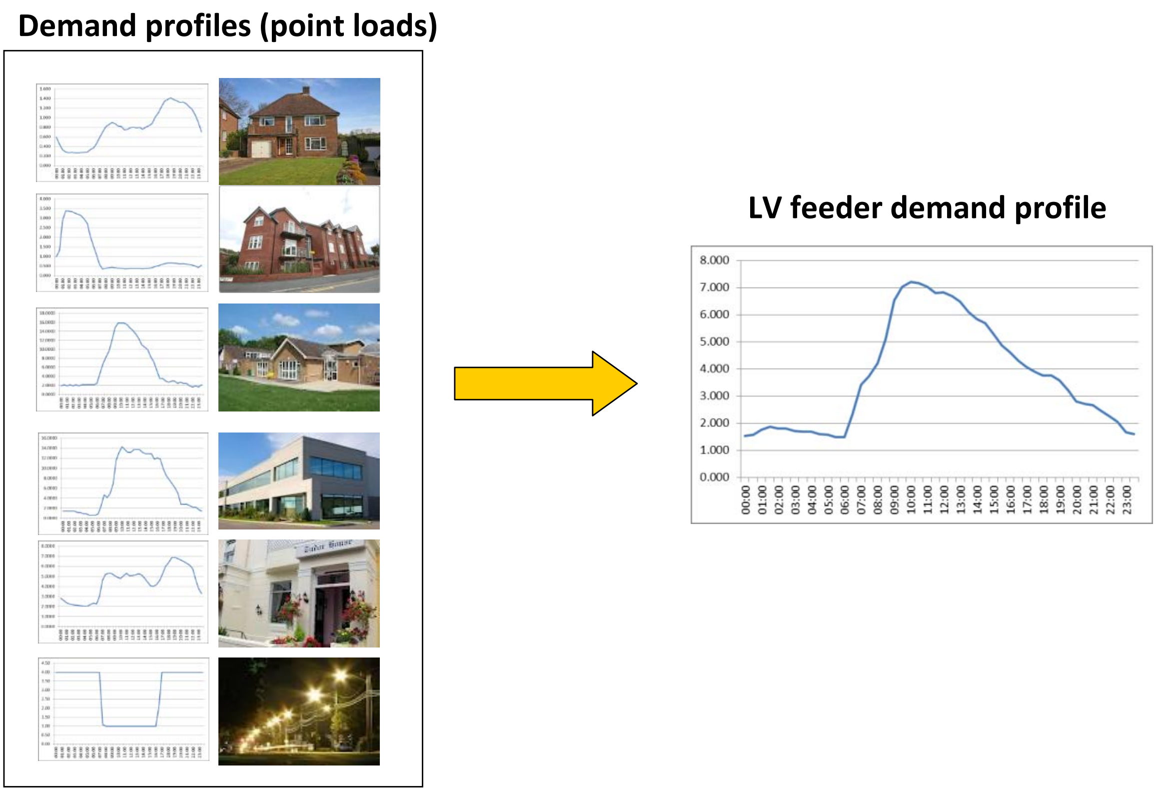


Figure 12.1 LV Feeder Loads (Source: GL Noble Denton)

The following sections explain how the building load profiles were developed and validated against available data. Profiles were generated under three sets of conditions covering winter peak, winter average and summer average (as per Work Stream 2).

12.1.1 Domestic buildings

The set of all domestic buildings can be categorised into four standard types (detached, semi-detached, terraced and flats) and four broad age bands (see Table 12.1 below).

Table 12.1 Domestic building type summary (Source: GL Noble Denton)

Very Old	Generally pre 1919. Solid wall construction. Flats of this age will be converted houses or tenements
Old	1919-1980. Predominantly cavity wall construction – mostly un-insulated
Modern	Post 1980. Predominantly cavity wall construction – mostly insulated
New	Highly insulated, zero carbon homes of the future

This level of detail is required for the modelling in order to capture the range in heat loss between different construction, size and age of houses. It is also important to ensure that any upgrades to houses are appropriate e.g. wall insulation applied to a terraced house will have less of an effect than on a detached.

In addition to these 16 house types, high rise flats have been considered. Although these only represent a small percentage of the overall population, they do cluster and so can be significant on a certain LV feeder. Nearly all high rise flats fall into the 'old' age category, so 17 categories were used to represent the full range of current and future domestic buildings in the UK. The building types and assumptions about the buildings were documented in two papers[55] [56].

Heat losses for each of the domestic building types were generated using the procedure defined in SAP 2009. This is a domestic energy rating procedure developed by BRE (Building Research Establishment). This energy rating is based on annual consumption and so provides an independent estimate of annual space heating, hot water and appliance consumption which can be used to validate the Energy Model results.

The age of a house tends to affect not only its construction (and therefore heat loss), but also its size e.g. a modern detached house is on average smaller than an old Victorian house both in terms of floor area and room height. The heat loss calculations rely on estimates of both the area and U-value of the building heat loss elements. For each building type, an average total floor area is used. U-values used in the calculations are based on building age, from which a construction type can be inferred. For example, older houses were built with a solid brick wall construction which was later

[55] 'WS3 Paper 006 – Building Types', GL Noble Denton, 14 March 2012.
[56] 'WS3 Paper 011a – Building and Appliance Efficiency V2', GL Noble Denton, 24 April 2012.

replaced with the use of cavity walls and then as building regulations became more stringent, these were insulated to different degrees. However, this represents the original construction of the building. It is recognised that a number of improvements will have already been made to some older properties. An allowance can therefore be made for this by estimating an average U-value based on the proportion of properties with improvements. This information has been obtained from the house condition surveys for England[57], Scotland[58] and Wales[59]. Changes to insulation levels of houses can be incorporated into the future scenarios by increasing the proportions of dwellings with retro-fit insulation and improvements to the effectiveness (U-value) of this insulation. In addition, for existing homes where a heat pump is installed there is assumed to be a minimum standard of insulation present. This is taken to include the following:

- 250mm loft Insulation
- Wall Insulation (Cavity fill or solid)
- Double Glazing
- Draught proofing

Finally the average number of occupants *N* in each domestic building type was estimated based on total floor area (*TFA*) using the following formula from SAP 2009[60]:

$$N = 1 + 1.76 \times (1 - e^{(-0.000349 \times (TFA - 13.9)^2)} + 0.0013 \times (TFA - 13.9)$$

Equation 1: Number of occupants as a function of total floor area

The domestic building details are summarised in Table 12.2 below.

Table 12.2 Domestic building type summary (Source: GL Noble Denton)

Building Type	Current Average Heat Loss (W/°C)	Heat Loss for Heat Pump Installation (W/°C)	Total Floor Area (m^2)	Number of Occupants
Very Old Detached	748.2	397.6	187.25	2.99
Old Detached	283.1	247.2	115.05	2.84
Modern Detached	204.0	180.8	124.36	2.88
Very Old Semi-Detached	530.2	293.6	124.95	2.88
Old Semi-Detached	243.9	205.4	90.63	2.63
Modern Semi-Detached	174.9	156.8	79.27	2.45
Very Old Terraced	329.2	204.5	95.15	2.69
Old Terraced	200.2	169.9	80.53	2.47
Modern Terraced	102.3	91.6	72.51	2.31
Very Old Flat	190.2	120.7	73.40	2.33
Old Flat	116.4	96.4	58.48	1.94

[57] English House Condition Survey 2007.
[58] Scottish House Condition Survey 2009.
[59] Welsh House Condition Survey 1998.
[60] The Government's Standard Assessment Procedure for Energy Rating of Dwellings, Building Research Establishment, 2009 edition.

Modern Flat	63.9	55.6	55.15	1.84
High Rise	100.9	85.9	57.13	1.90
New Detached	119.2	119.2	124.36	2.88
New Semi-Detached	115.0	115.0	79.27	2.45
New Terraced	68.6	68.6	72.51	2.31
New Flat	43.8	43.8	55.15	1.84

Using this information GL Noble Denton was able to use their Energy Model to produce electricity demand profiles for each building type. The Energy Model enables consumption profiles to be generated for a building by simulating the interactions between the building, the environment, all appliances within the building and the building occupants on a minute by minute basis. The output from the model is in the form of three profiles representing gas consumption, electricity consumption and electricity generation. These profiles can be further split be end use type e.g. heating, cooking etc.

By varying the building and appliance properties, the Energy Model was used to generate estimates of future profiles taking into account higher building insulation standards and improved appliance efficiencies. Environmental conditions were also varied to assess seasonal and regional variation. When a simulation is performed for a particular building type, a number of building instances are generated. These are all of the same basic construction type but will have different appliances randomly generated based on specified probabilities. Users are also simulated on a probabilistic basis around typical activities at different times of the day. The appliance models then simulate the energy consumption/generation behaviour of each appliance in response to demand inputs (from users or controls) and, where relevant, to internal building temperatures or the state of other related appliances. By performing multiple simulations, the Energy Model accounts for diversity within groups of buildings of the same type to determine a diversified profile.

12.1.2 Domestic space heating profiles

Fully diversified electricity demand profiles were generated for each building type for three different electric heating systems:

- Direct acting resistive heaters
- Storage heaters (Economy 7)
- Heat pumps

For the case of summer average, it is assumed that there is no heating demand. In order to generate average and peak winter heating demands, simulations were run at external temperatures of -5°C and +5°C, with an average room set temperature of 18°C. This range of external temperatures is assumed to cover the range of peak and average winter temperatures which occur in different regions of the UK. Heating profiles at specific temperatures in this range can be calculated by interpolating between the two set of profiles. In order to allow incorporation into the WS3 model the heating profiles were averaged across all domestic building types to produce average profiles.

A number of important assumptions were made during the modelling of heat pump demands. First, the heat pumps were assumed to be air-to-water air source heat pumps with a COP given by:

$$2.184 + 0.098 \times T \qquad \text{for } -5 \leq T \leq 5$$

This relationship between efficiency and temperature is taken from a presentation by Gastec[61] based on appliance test data. It was also assumed that the heat pumps are supplemented by a small top-up electric resistive heater (with a COP of 1) which starts to be used when the external temperature falls below 2°C.

There is some debate over how users will operate heat pumps. It has been suggested that they may run in a continuous manner due to the lower grade heat output required to maintain high COP values. This mode of operation would also help mitigate the peak demands in early morning and evening as many heating systems start up. However, continuous operation keeps the building at a higher average temperature and thus uses more energy overall, effectively negating some of the benefit of high COP values. This additional energy requirement could be up to 20%[62]. Only very limited heat pump field trial data was made available to GL Noble Denton for this study, but this showed heat pumps operating in an intermittent manner.

Heat pumps were therefore assumed to be run intermittently (on demand giving a diurnal profile shape). However, to recognise the fact that heat pumps may struggle to provide sufficient heat to warm up a building from cold under peak conditions, a second, lower set temperature of 14°C was used outside of the hours of normal heating system operation. This allows the heat pump to operate more continuously in very cold conditions.

Figure 12.2 below shows representative profiles for the three systems.

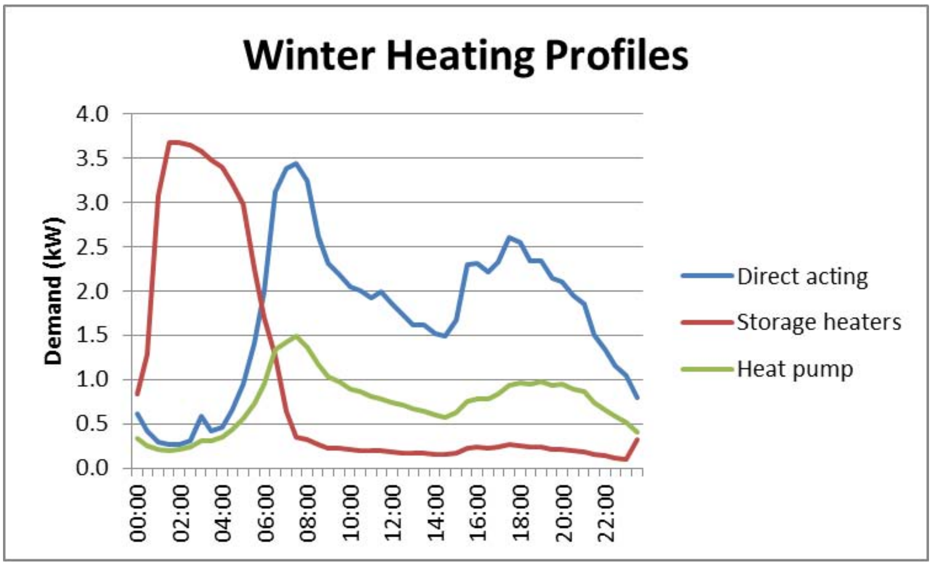


Figure 12.2 Heating system profiles (Source: GL Noble Denton)

Further analysis of heat pumps was carried out to quantify the possible effect of combining them with a 100-400 litre (depending on building size) thermal store. Assuming that water is stored at 55°C our analysis showed that averaged across all domestic building types the storage could provide

[61] Linking gas boilers to heat pumps, Gastec at CRE Ltd, November 2005.
[62] Linking gas boilers to heat pumps, Gastec at CRE Ltd, November 2005.

enough heat to maintain a comfortable internal temperature for around 1hr 20min at an external temperature of 5°C, falling to around 20min at -5°C. Figure 11.3 below shows the potential impact of using a thermal store on household space heating demand. The thermal store is charged during off-peak allowing the heat pump to be turned off around the time of peak demand.

A separate profile was not generated for a heat pump with thermal storage. The effect of thermal storage is accounted for in the model by moving demand from peak to non-peak times. The potential amount of demand which can be moved is based on the above analysis.

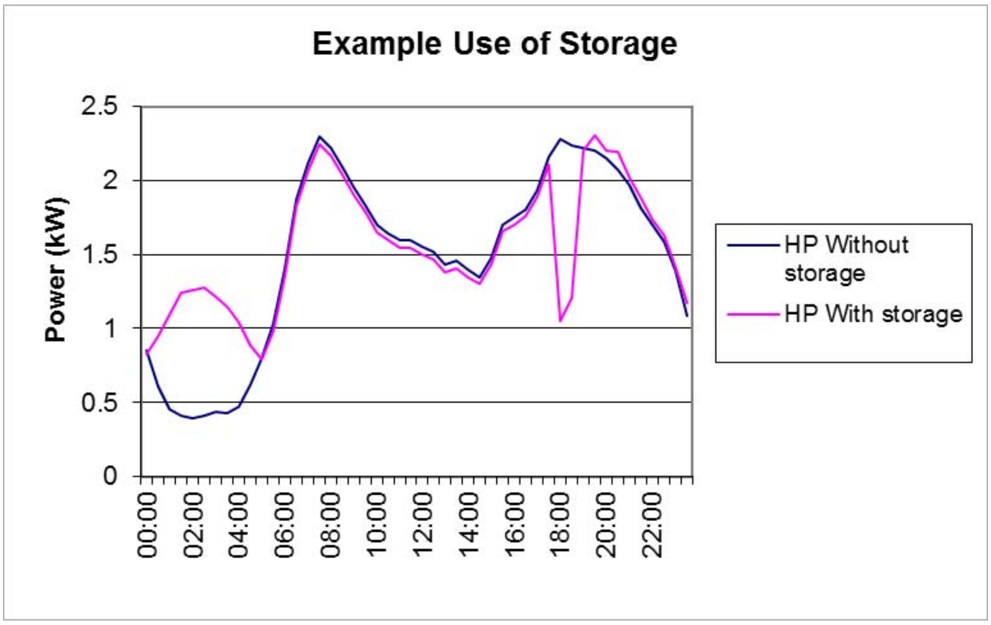


Figure 12.3 Assessment of heat pump thermal storage potential (Source: GL Noble Denton)

12.1.3 Domestic appliance profiles

The Energy model was also used to generate fully diversified demand profiles for the following end use categories based on an average number of occupants:

- Lighting (both summer and winter profiles)
- Wet appliances (washing machine, dishwasher, tumble drier)
- Cold appliances (fridge, freezer)
- Cooking (oven, hob, microwave, kettle)
- Consumer Electronics (TV, DVD, digital receiver, games console, PC, laptop, printer, mobile device charging)
- Hot water

Figure 12.4 below shows the appliance demand composition for an average property in winter.

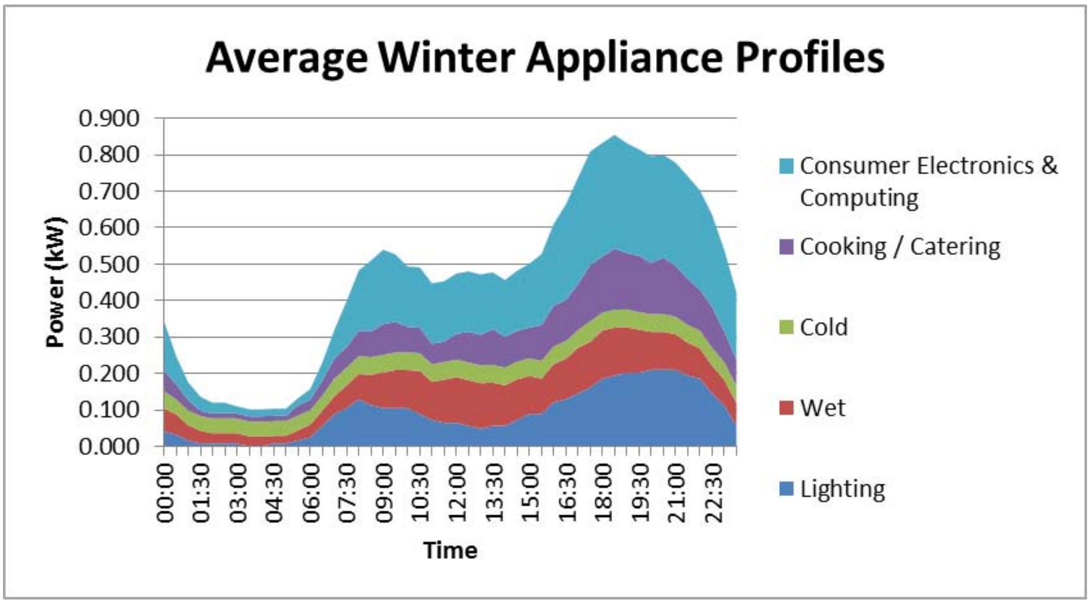


Figure 12.4 Appliance profiles (Source: GL Noble Denton)

These profiles are based on individual appliance models. Ownership levels for appliances have been taken to be the 2010 values from an earlier study[63]. Information about times and duration of operation are inferred from the time use survey[64]. This provides information about what activities people are involved in at different times of day. Figure 12.5 is a high level example. The survey data contains more detail than shown here.

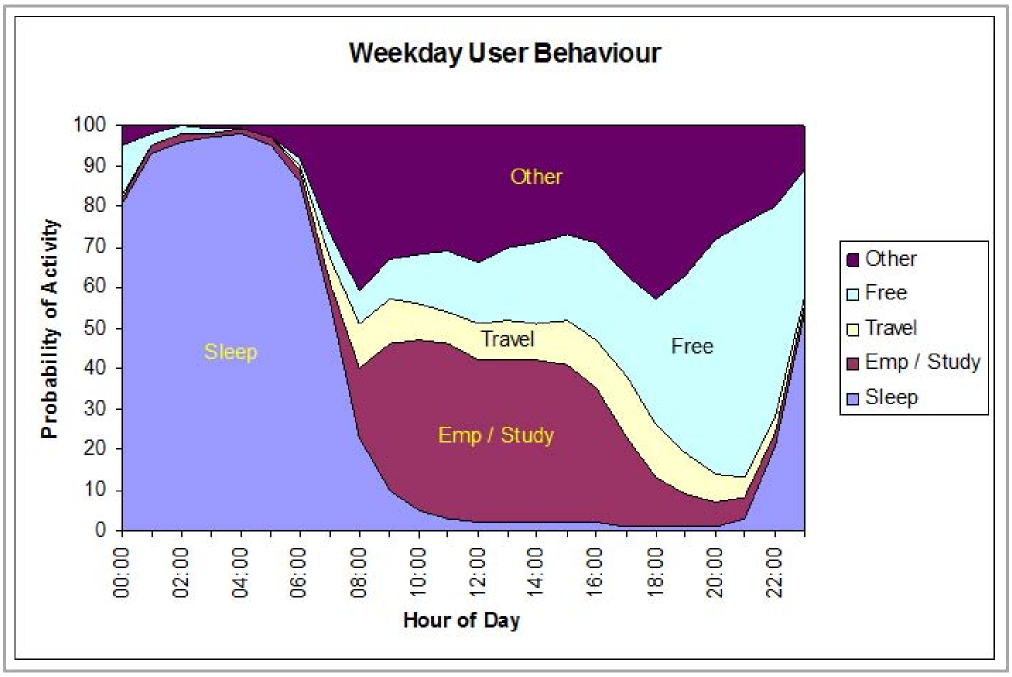


Figure 12.5 Time use survey data overview (Source: GL Noble Denton)

63 Scenarios Report - 'Scenarios for new/renewable energy systems and controls over the next 30 years', report no 8754, GL Industrial Services (Advantica), March 2009.

64 United Kingdom Time Use Survey, Office for National Statistics, 2000.

The average non-heat profiles were used to provide profiles for all domestic buildings by using the following formulae from SAP 2009[65] to scale the profiles based on floor area and derived number of occupants for each house type:

$$E_L = 59.73 \times (TFA \times N)^{0.4714}$$

Equation 2: Average annual energy consumption for lighting

$$E_A = 207.8 \times (TFA \times N)^{0.4714}$$

Equation 3: Average annual energy consumption for electrical appliances

$$V = (25 \times N) + 36$$

Equation 4: Annual average hot water usage in litres per day

The SAP 2009 methodology was also used to scale the load profiles for the variation between summer and winter.

$$E_m = E_L \times [1 + 0.5 \times \cos\left(2\pi \times \frac{(m - 0.2)}{12}\right)]$$

Equation 5: Average daily energy consumption for lighting in month *m*

$$E_m = E_A \times [1 + 0.157 \times \cos\left(2\pi \times \frac{(m - 1.78)}{12}\right)]$$

Equation 6: Average daily energy consumption for electrical appliances in month *m*

Electricity demand for hot water was scaled to account for the variation in demand with input water temperature using the following monthly factors:

Table 12.3 Seasonal hot water factors (Source: GL Noble Denton)

	Winter	Summer
Demand factor	1.1	0.9
Temperature factor	41.2	33.9

Although the WS3 model was aimed primarily at assessing the effect of uptake of electric vehicles, electric heating (heat pumps) and solar PV, it is recognised that there will be changes in terms of both the number and efficiencies of other electrical appliances. Information from the Market Transformation Programme has been used to derive scaling factors for lighting and electrical appliance consumption which takes account of anticipated efficiency improvements[66]. Details of the methodology for applying these scaling factors within the model are given in the paper 'Building and Appliance Efficiency'[67].

[65] The Government's Standard Assessment Procedure for Energy Rating of Dwellings, Building Research Establishment, 2009 edition.
[66] Market Transformation Programme (http://efficient-products.defra.gov.uk/)
[67] 'WS3 Paper 011a – Building and Appliance Efficiency V2', GL Noble Denton, 24 April 2012.

12.1.4 Domestic PV profiles

Three supply profiles were generated for a PV installation with 3.8pkW output. This corresponds to a large domestic installation and so is scaled down when applied to smaller properties due to restricted roof space. These profiles represent the generation expected from a single PV installation and so are not diversified. Given that an individual LV feeder will cover a limited geographical area, there will be little, if any diversification i.e. all panels will be experiencing similar levels of incident solar radiation.

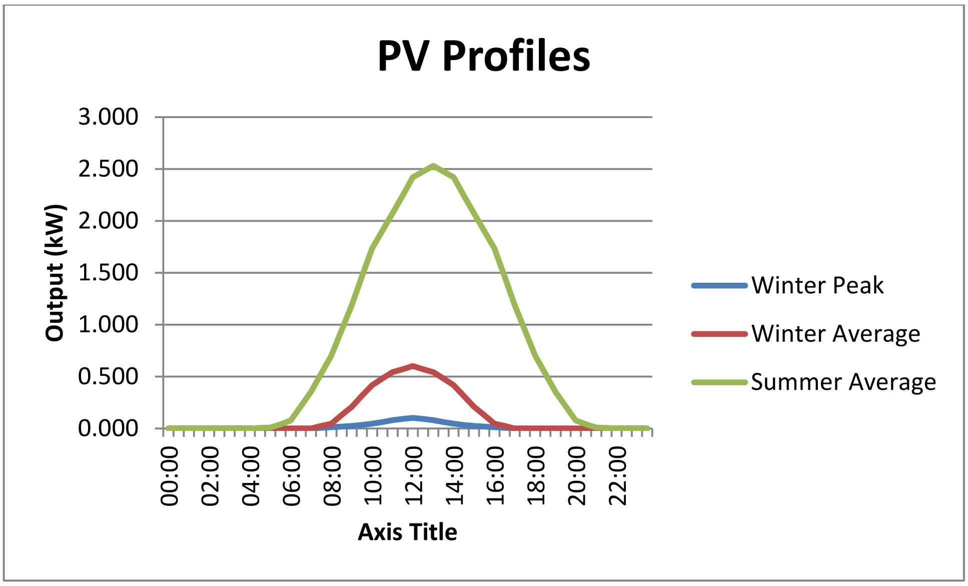


Figure 12.6 Domestic PV profiles (Source: GL Noble Denton)

These profiles were generated based on a sample of two years of radiation data.

12.1.5 Domestic profile validation

A number of validation checks were performed to confirm the validity of the estimated profiles for 2012 as described below.

The appliance models and consumption were compared to the CREST (Centre for Renewable Energy Systems Technology) electricity demand model developed at Loughborough University[68] and showed a good level of agreement. The CREST model has been validated against field data for a sample of homes in the East Midlands region. This estimates electricity demand on a minute by minute basis for domestic appliances but does not include heating demand. Having scaled the load profiles for each appliance type to their yearly average they were compared to data from DECC[69]. The split in energy use is summarised in the table below:

[68] 'Domestic electricity use: A high-resolution energy demand model', Ian Richardson, Murray Thomson, David Infield and Conor Clifford, 2010 (https://dspace.lboro.ac.uk/dspace-jspui/bitstream/2134/6997/1/Domestic%20electricity%20demand%20model%20paper%20_2%2000_%20A.pdf).
[69] Energy Consumption in the UK, Domestic data tables, 2011 update, Department of Energy and Climate Change.

Table 12.4 Estimated UK domestic electrical end-use (Source: GL Noble Denton)

End Use	% of domestic electrical load
Light	13.75%
Cold	13.49%
Wet	13.80%
Consumer electronics	20.13%
Home computing	6.28%
Cooking	12.70%
Hot water	5.81%
Heating	14.04%

The shape of the total demand profile and half-hourly peak were compared to the average Elexon profile data for profile classes 1 and 2 (Domestic unrestricted and domestic Economy 7). In order to do this it was necessary to distinguish between domestic properties on unrestricted and Economy 7 tariffs. This was done using the following information:

- 81.5% of domestic customers are allocated to profile class 1 and 18.5% to profile class 2. However, no information about the split by building type is available i.e. we do not know if profile class 2 is skewed towards smaller houses
- According to the housing condition surveys only 7.7% of all domestic properties have storage heaters as their primary heating system. Therefore we can infer that 41.7% of properties in profile class 2 actually use storage heaters. The house condition surveys
- According to the housing condition surveys, 1.8% of all properties have direct acting electric heating. This was taken to be in profile class 1, giving 2.3% of those properties

Figures 12.7 and 12.8 below show the comparisons for profile classes 1 and 2 respectively. For profile class 1 the agreement is excellent.

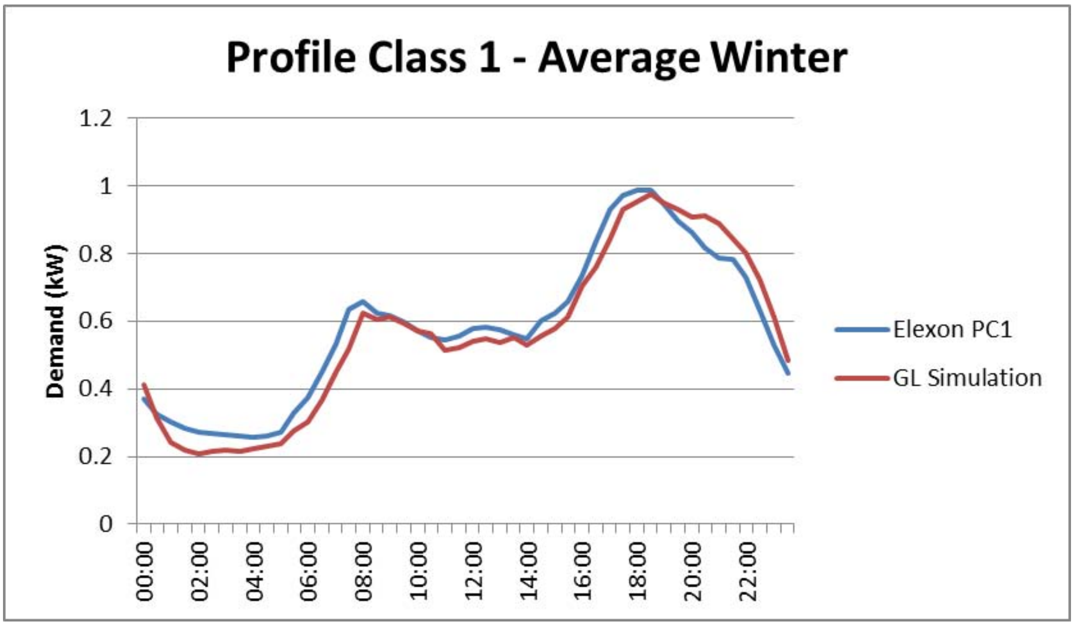


Figure 12.7 Comparison with Elexon Profile Class 1 (Domestic Unrestricted) (Source: GL Noble Denton)

For comparison purposes, it was necessary to build up a pseudo-class 2 profile. This is required because the simulated profiles are by heating system and house type. To allow a comparison with the Elexon profile, these need to be combined to represent a similar composition of houses and heating systems as those that make up the Elexon profile class 2. There is data on the number of storage heating systems from the house condition surveys (based on a sample), but no reliable information on the number of each house type in profile class 2. Although the house condition survey data is the most up to date, it will not be fully representative of 2012. The latest housing condition survey reports are dated 2007 for England, 2009 for Scotland and 1998 for Wales, but the actual survey periods will be earlier than this.

For profile class 2, data provided by Elexon showed a sharp fall in the overnight peak of the switched load. Data from 2002/3 had an overnight peak of approximately 2.1kW compared with 1.5kW based on most recent data. Given this sharp fall in switched demand it was decided to scale the simulated profiles to match the Elexon switched demand. The resulting scaled profile is shown in Figure 12.8 **Error! Reference source not found.**for comparison with the Elexon data.

Further validation of the profile class 2 profiles was achieved through comparison with WinDEBUT profiles. The profile for an Economy 7 (Electricaire) heating system shows a night peak about 1.7 times the size of the evening peak which is slightly higher than the simulated ratio.

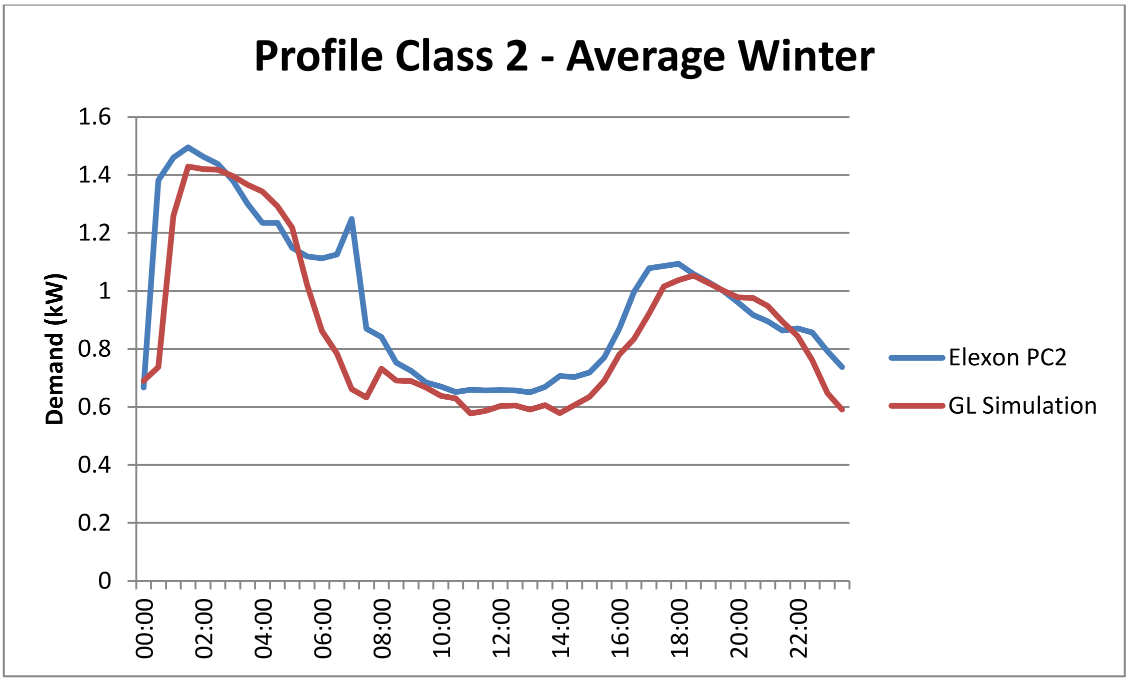


Figure 12.8 Comparison with Elexon Profile Class 2 (Domestic Economy 7) (Source: GL Noble Denton)

12.1.6 Non-domestic buildings

The set of non-domestic buildings was modelled using the seven most prevalent types identified through analysis of Valuation Office Agency data on numbers of premises and floor space by usage class, with retail further split to allow for different opening hours. Details are provided in the 'Building Types' paper[70].

- Retail (high street)
- Retail (extended opening)
- Office
- Education
- Hotel
- Pubs/Clubs/Restaurants
- Warehouses
- Other/Industrial

The aim of the selection for non-domestic properties is to capture the different energy use patterns and opening hours. Another important consideration for the non-domestic building types is the availability of data to validate the profiles. For this reason (and ease of application) a slightly different set of end-use demand profiles were generated for non-domestic buildings than for domestic:

- Lighting (assumed to have much less seasonal variation than domestic lighting)
- Catering
- Computing
- Hot water
- Cooling and ventilation
- Other

The PV profiles generated for domestic buildings are equally applicable when scaled to non-domestic buildings.

The relative size of end-use loads was calculated using data from DECC[71,72], summarised below.

[70] 'WS3 Paper 006 – Building Types', GL Noble Denton, 14 March 2012.
[71] Energy Consumption in the UK, Service sector data tables, Department of Energy and Climate Change, 2011 update.
[72] Energy Consumption in the UK, Industrial data tables, Department of Energy and Climate Change, 2011 update.

Table 12.5 Estimated UK Non-Domestic Electrical End-Use (Source: GL Noble Denton)

Sub-sector	Catering	Computing	Cooling and Ventilation	Hot Water	Heating	Lighting	Other
Commercial Offices	3.3%	14.9%	21.4%	2.2%	19.8%	32.3%	6.1%
Education	10.8%	12.2%	1.6%	6.9%	8.4%	51.3%	8.8%
Hotel and Catering	34.2%	0.6%	10.7%	5.4%	7.2%	32.1%	9.9%
Retail	15.2%	4.3%	9.9%	2.9%	14.3%	43.4%	10.0%
Warehouses	6.4%	3.5%	5.5%	0.9%	14.2%	43.1%	26.3%
Industry					7.8%	2.8%	89.4%

The size of the total load for each building was normalised by assuming an E.A.C. of 1kWh. The shape of the appliance profiles were based on WinDEBUT profiles and validated against Elexon profiles.

Non-domestic buildings are much more varied in terms of their construction and therefore heat loss. There is also less data available regarding non-domestic buildings. For these reasons, a different approach was taken from the domestic buildings, which does not rely on estimating an accurate heat loss. A base resistive heating profile at 5°C was generated. Based on simulations with a range of different heat losses, a demand-temperature relationship was derived. A heat pump profile was then derived from this by scaling the consumption to take account of the higher efficiency. Storage heater profiles were derived from the difference between the unrestricted and restricted versions of the WinDEBUT profiles.

12.1.7 Non-Domestic profile validation

Figure 12.9 compares scaled versions of the Elexon and the simulated demand profile for profile class 3 (unrestricted non-domestic), to validate the shape. The simulated profiles are a weighted average of profiles for the different building types weighted by total UK consumption for each non-domestic sub-sector. Note that this takes no account of those buildings which will fall into profile classes 5-8 or are half-hourly metered.

Estimates from Sustainability First[73] suggest that around 14% of non-domestic electric heating occurs off-peak. However, there are not enough details on the make-up of profile class 4 (in terms of building types or number of storage heating systems) to make a realistic comparison with Elexon profiles.

[73] GB Electricity Demand – Context and 210 Baseline Data, Sustainability First, October 2011.

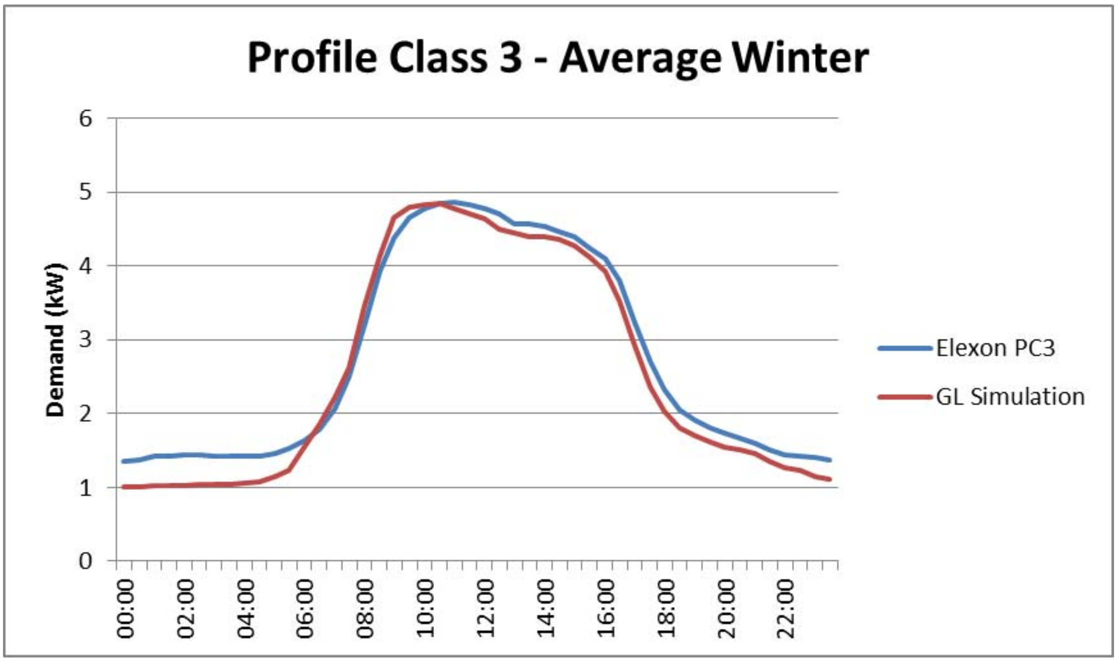


Figure 12.9 **Comparison with Elexon Profile Class 3 (Source: GL Noble Denton)**

12.1.8 Non-Building Demand

The non-building related demands consist predominantly of street lighting including traffic lights and signage. Some of this demand will be present during hours of darkness only, whilst some demand will be present throughout the day.

Data provided by Elexon showed that 95% of street lights operated on an all-night basis (either timed or with photocell). Street lighting was therefore modelled as a switched load which operates during hours of darkness only. It should be noted that this mode of operation may change in future. Two simple profiles were generated for street lights based on sunrise and sunset times for winter and summer. These profiles represent a single street light which is switched to come on half an hour after sunset and then switch off half an hour before sunrise (standard UK lighting up times). This profile can then be scaled according to the average street light power and the number of street lights.

Having estimated the night-time only part of the non-building related demand it was necessary to add in some demand which is present throughout the day. An estimate of the split between continuous and night-time only demand was available from data provided by Elexon which gave the annualised energy for NHH unmetered demand. This data showed 35% of unmetered demand was continuous. To generate the total non-building related demand profile, the daily total for the night-time only demand was used to estimate the continuous demand for the day given that 35% of the total should be continuous. This continuous demand was then apportioned equally across the day. An example profile for non-building related demand in winter is given in Figure 11.10. This assumes 10 street lights of average power 300W.

As street lights are on continuously they will not diversify. The intermittent load (classes as continuous) has already been averaged across the day. No further diversity corrections are therefore required for the non-building demand.

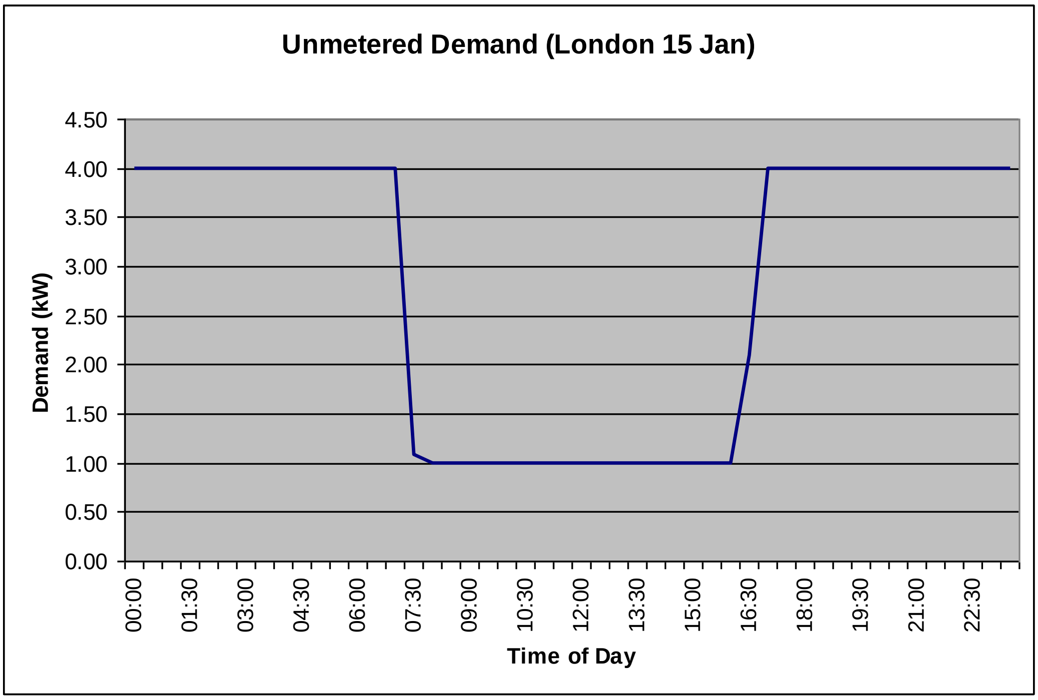


Figure 12.10 Example non-building related demand profile (Source: GL Noble Denton)

Given the fact that certain local councils are moving towards installing low energy street lighting, it is anticipated that in a great number of areas this type of demand will fall by 90%. As the impact it has on overall load profiles is already small, it will become sufficiently small to be completely negligible in terms of the scale of load being considered by the model. In order to model this, it meant fairly complicated inputs required by a user regarding the amount of street lighting that is low energy and how this varies over time. Therefore, the decision has been taken to exclude this load form the model for the time being. There are spare profiles that could be populated with street lighting data should a user wish to include this level of detail.

12.2 Diversity

The individual demand profiles generated by GL Noble Denton represent fully diversified profiles (with the exception of the street lighting and PV profiles which should not be diversified). The diversity is a direct result of the fact that 3,000 simulations have been run for each building type. However, when combining profiles at the LV feeder level where there are a relatively small number of consumers, peak loads may be higher than the diversified profiles suggest.

When considering peak demands it is also important to understand that the measurement timescale is important. Figure 12.11 shows simulated demand for a single heat pump at minutely granularity together with the same data aggregated to half hourly. This shows that the peak demand over a larger time interval is usually less than the instantaneous peak demand over the same period.

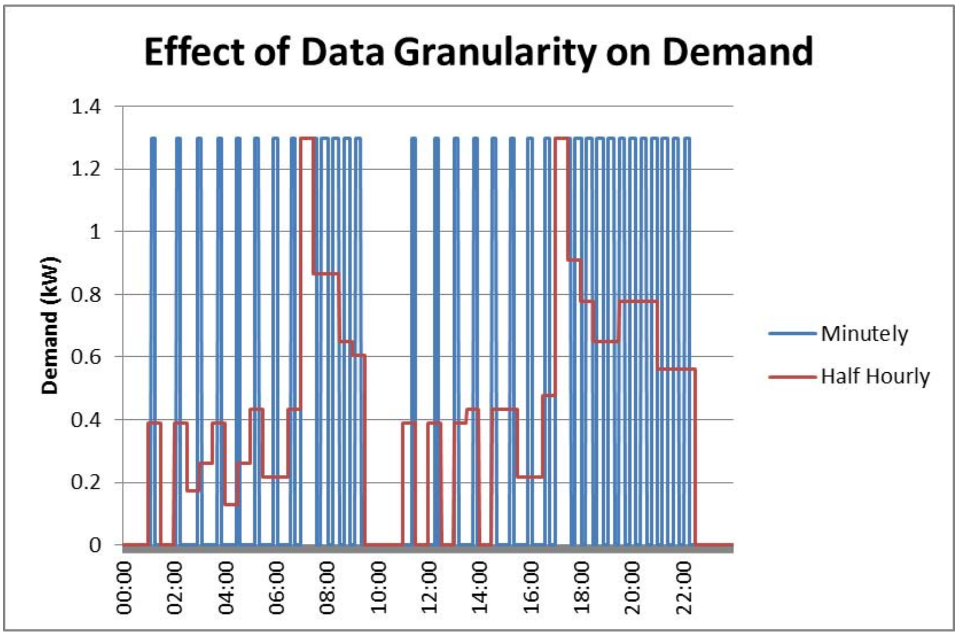


Figure 12.11 Example of measurement granularity effect on peak demand (Source: GL Noble Denton)

Diversity is a result of consumers' demand profiles not aligning exactly. Consider two consumers with the same daily consumption. The total daily consumption will simply be twice the daily consumption for one consumer. However, unless the timing of the peak demands aligns exactly (very unlikely), then the peak demand for the two consumers together will be less than the sum of the peak demands. Figure 12.12 demonstrates this, showing simulated domestic electricity profiles. One curve represents the demand for a single home compared to another which represents the average of many homes (3,000). Note that in this case, the daily demand for the single house is greater than the average of the 3,000 houses. Diversity acts like a smoothing filter. It does not change the overall average level of demand but does reduce the size of the average peak.

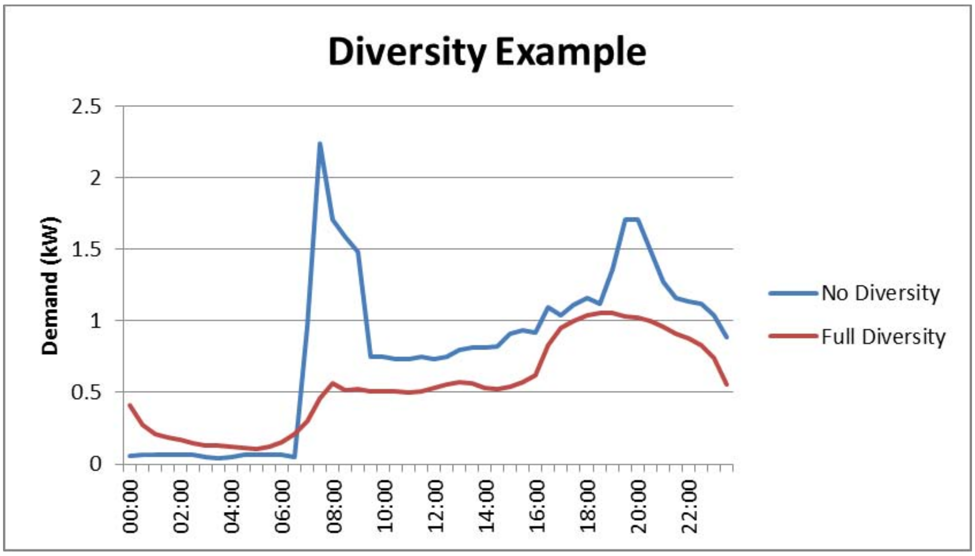


Figure 12.12 Example of Diversity: One house vs. many

Figure 12.3 is a typical diversity curve. It shows how the average peak demand per house (y-axis) varies with the number of houses being aggregated (x-axis). The shape of the curve results from the statistical properties of the data, with the rate of decrease in average peak demand being proportional to 1/√N where N is the number of houses to be aggregated.

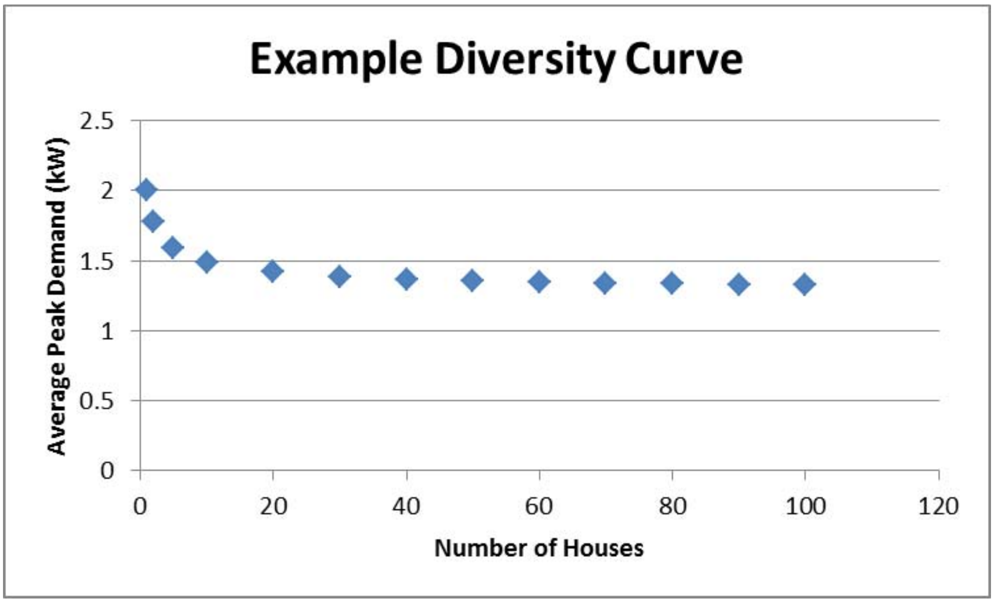


Figure 12.13 Example Diversity Curve (Source: GL Noble Denton)

Given this relationship (Equation 7), it is possible to estimate the aggregated peak demand for any number of profiles (diversified peak demand for n houses Pnd) from the peak demand of the fully diversified profile (Pfd). A good first estimate for the factor of proportionality (f) is 1, based on experience and as suggested in the WinDEBUT user guide[74].

$$Pnd=Pfd*(1+f/\sqrt{n})$$

Equation 7: Diversity Adjustment

12.3 Feeder composition

Analysis of DNO networks has revealed the common classifications of LV feeders

- Customers of certain profile classes
- Number of customers
- Characterise these in terms of number of connected customers (domestic and commercial)
- Map these feeder types onto the standard model LV feeders
- At higher voltages; assumptions regarding the number of lower voltage feeders that are supplied by each type

[74] 'Debut User Guide', L Kerford, March 2001.

13 Appendix D: Further Information on the Smart and Conventional Solutions

13.1 Smart Solutions

13.1.1 The 12 Solution Sets as taken from WS3 Phase 1 Report

Table 13.1 The 12 solution sets as taken from the WS3 Phase 1 report

	POTENTIAL RESPONSES for 2020 Transmission & Distribution (typically Smart Grid 1.0) Solution Sets - capabilities for 2020	POTENTIAL RESPONSES for 2030 Transmission & Distribution (typically Smart Grid 2.0) Solution Sets - capabilities for 2030 & beyond
Focus: Quality of Supply; enhancements to existing network architecture	**1. Smart D-Networks 1 (Supply & Power Quality)** 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 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)	**full functionality:** Integration of storage (P/Electronics 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
Focus: DG connections, management of 2-way power flows	**2. Smart D-Networks 2 (Active Management)** 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	**full functionality:** 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
Focus: plant & systems reliability, failure mode detection	**3. Smart D-Networks 3 (Intelligent Assets)** 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	**full functionality:** Diagnostic tools for managing intelligent control systems Re-commissioning tools and techniques for extending/scaling intelligent control systems Loss optimisation techniques - utilise new devices such as D-FACTS Fault localisation and diagnostic techniques
Focus: Security of networks inc. physical threats, utilising new network architectures	**4. Smart D-Networks 4 (Security & Resilience)** 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	**full functionality:** Self-healing network diagnostics and responses Self islanding option for extreme physical events (essential supplies) 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
Focus: Enhancements to Transmission Networks to add to existing smart functionality & whole-system perspective	**5. Smart T-Networks (Enhancements)** Extension of dynamic ratings to all plant types Monitoring and adaptation of assets subjected to high utilisation Extension of FACTS devices for increased ac transfer capabilities Advanced dynamic sensing and stability monitoring Utilisation of aggregated D-Network DR services Utilisation of aggregated D-Network export services (DG/VPP/V2G) New and enhanced forecasting and modelling for EVs and Wind Generation impact (demand/export) Condition Monitoring for ageing assets - failure advance warnings for lines, cables, transformer and switchgear	**full functionality:** Integration of DNO/DNO/TSO data, analysis, and information Utilisation of aggregated fast D-Network DR/VPP/Storage services for response and reserve Wider use of DC internal and external links and integration of their control systems for secure and stable operation Whole system, all voltage level, integration - see (1) also

Focus: EV charging / discharging (V2G), Network Management, Demand Response and other services	**6. Smart EV Charging** Open Systems with standardised communication protocols and standardised functionality for EVs/Charging Points Architecture - distributed processing - street, substation or community level, distributed charging management, with aggregated reporting and supervision for reliability Commercial frameworks required	**full functionality:** Integration of local storage to support charging capability Demand Response aggregated services (downward/upward) Aggregated V2G services Forecasting and modelling, integrated for DNO/DNO/TSO Standardised functionality available for rapid wider roll-out
Focus: Electricity storage at domestic, LV, and MV levels, and above (static storage devices)	**7. Smart Storage** 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	**full functionality:** 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
Focus: Geographic and social communities in existing built environment	**8. Smart Community Energy** Enhance network performance by forging closer links with those it ser 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	**full functionality:** 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
Focus: SME, C & I buildings, and all aspects of new Built Environments	**9. Smart Buildings & Connected Communities** 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	**full functionality:** 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
Focus: Ancillary Services for local and national system	**10. Smart Ancillary Services (Local & National)** Aggregation of domestic DR (downward response) Aggregation of EV charging (variable rate of charging) Commercial frameworks Aggregation of DG (eg PV) to provide Virtual Power Plant (VPP) capa	**full functionality:** Aggregation of domestic DR (downward/upward responses) Aggregation of EV charging (variable charging/discharging) DSOs manage local networks, 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
Focus: T&D control centres of the future	**11. Advanced Control Centres** Visualisation and decision support tools Data processing at lowest levels, information passed upwards Modelling & Forecasting tools for new demands, in Ops timescales	**full functionality:** 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
Focus: Enterprise wide platforms within companies	**12. Enterprise-wide Solutions** Facilities that provide cost-effective outcomes, across Solution Sets This may apply to Enterprise-wide communications, data storage etc	**full functionality:** 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

13.1.2 Converting the WS3 Ph1 report to a set of solutions for quantification

Table 13.2 Overview of the solutions inputted in the model as they relate to the WS3 Phase 1 solution sets

	v1.0	v2.0
Solution Set	**Solution**	**Solution**
Smart D-Networks 1	Active Network Management - Dynamic Network Reconfiguration	
	Temporary Meshing (soft open point)	
	Distribution Flexible AC Transmission Systems (D-FACTS)	
	Electrical Energy Storage	
	Switched Capacitors	
Smart D-Networks 2	fault current limiters	DSR
	Electrical Energy Storage	Electrical Energy Storage
	Enhanced Automatic voltage Control (EAVC)	
	Generator Constraint Management, GSR (Generator Side Response)	
	Generator Providing Network Support, e.g. PV Mode	
Smart D-Networks 3	RTTR	Distribution Flexible AC Transmission Systems (D-FACTS)
	New Types Of Circuit Infrastructure	
Smart D-Networks 4	Active Network Management - Dynamic Network Reconfiguration	Embedded DC Networks
	Permanent Meshing of Networks	Active Network Management - Dynamic Network Reconfiguration
		Electrical Energy Storage
Smart T-Networks	RTTR	DSR
	DSR	
Smart EV charging	Local smart EV charging infrastructure	Electrical Energy Storage
		Local smart EV charging infrastructure
Smart storage	Electrical Energy Storage	Electrical Energy Storage
		RTTR
Smart Community Energy		DSR
Smart buildings and connected communities	DSR	
	Electrical Energy Storage	
Smart Ancilliary services (local and national)		
Inter-sector energy transfer		DSR
		Electrical Energy Storage
Conventional	Split feeder	
	New split feeder	
	New transformer	
	Minor works	
	Major works	

13.1.3 Selected Smart Solutions

The final smart solutions set can be seen below. The solutions are a blend of technologies and commercial contracts and have been categorised into a core set of 15 representative smart solutions each with a number of associated variants. This reduced the numbers to a much smaller set of broader categories which could then be reviewed for agreement.

It is important to note that many of the technologies have cross solution capabilities, for example Electrical Energy Storage (EES) can provide functions for *Intelligent Voltage Control* and *Waveform Correction*. Such solutions have been identified within the spreadsheet as 'Duplicates' to ensure that each technology is not considered for multiple scenarios whilst at the same time showing solutions within each category.

Table 13.3 Selected smart solutions

SMART SOLUTIONS	WS2 Model	WS3 Model
Active Network Management - Dynamic Network Reconfiguration[75]		
EHV	Y	Y
HV	Y	Y
LV	Y	Y
Distribution Flexible AC Transmission Systems (D-FACTS)		
EHV connected STATCOM	Y	Y
HV connected STATCOM	Y	Y
LV connected STATCOM	Y	Y
D-FACTS@ EHV	N	Y
D-FACTS@ HV	N	Y
D-FACTS@ LV	N	Y
DSR		
DNO led residential DSR	Y	Y
DNO to aggregator led commercial DSR	N	Y
DNO to commercial DSR	N	Y
Retailer led residential DSR (no DNO services)	Y	Y
Retailer led residential DSR with DSO ancillary services	Y	Y
DNO to Community DSR	N	N
DNO to Central business District DSR	N	Y
Aggregated DNO services for TSO benefits	N	N
Electrical Energy Storage		
EHV connected EES - large	N	Y
EHV connected EES - medium	Y	Y
EHV connected EES - small	N	Y
HV connected EES - large	N	Y
HV connected EES - medium	Y	Y

[75] "Dynamic network reconfiguration" refers to the pro-active movement of network split points to align with the null points within the network.

HV connected EES - small	N	Y
LV connected EES - large	N	Y
LV connected EES - medium	Y	Y
LV connected EES - small	N	Y
V2G Storage	N	N
HV Central Business District (commercial building level)	N	Y
Embedded DC Networks		
In business DC Networks	N	N
In Home DC networks	N	N
Embedded DC@EHV	N	Y
Embedded DC@HV	N	Y
Embedded DC@LV	N	Y
Enhanced Automatic voltage Control (EAVC)		
HV/LV Transformer Voltage Control	Y	Y
LV circuit voltage regulators	Y	Y
HV circuit voltage regulators	Y	Y
EHV circuit voltage regulators	Y	Y
LV PoC voltage regulators	N	Y
Fault Current Limiters		
EHV Superconducting fault current limiters	N	Y
HV Superconducting fault current limiters	N	Y
EHV non-superconducting fault current limiters	N	Y
HV non-superconducting fault current limiters	N	Y
HV reactors - mid circuit	N	Y
LV reactors - distribution s/s	N	N
LV reactors - mid circuit	N	N
Generator Providing Network Support, e.g. PV Mode		
Generator support @ EHV	N	Y
Generator support @ HV	N	Y
Generator support @ LV	N	Y
Local smart EV charging infrastructure		
Intelligent control devices	N	Y
Micro Grids		
Islanding of DG	N	N
Micro grids	N	N
RTTR		
RTTR for EHV OH lines, coupled with demand forecast	Y	Y
RTTR for HV OH lines, coupled with demand forecast	Y	Y
RTTR for LV OH lines, coupled with demand forecast	Y	Y
RTTR for EHV UG cables, coupled with demand forecast	Y	Y
RTTR for HV UG cables, coupled with demand forecast	Y	Y
RTTR for LV UG cables, coupled with demand forecast	Y	Y
RTTR for EHV/HV Tx, coupled with demand forecast	Y	Y
RTTR for HV/LV Tx, coupled with demand forecast	Y	Y

Switched Capacitors		
Switched capacitors @ EHV	Y	Y
Switched capacitors @ HV	Y	Y
Switched capacitors @ LV	Y	Y
Temporary Meshing (soft open point)[76]		
EHV - maximising latent capacity	N	Y
HV - maximising latent capacity	N	Y
LV - maximising latent capacity	N	Y
New Types Of Circuit Infrastructure		
Novel EHV tower and insulator structures	N	Y
Novel HV tower and insulator structures	N	Y
Novel EHV underground cable	N	Y
Novel HV underground cable	N	Y
Generator Constraint Management, GSR (Generator Side Response)		
EHV GSR (Generator Side Response)	N	Y
HV GSR (Generator Side Response)	N	Y
LV GSR (Generator Side Response)	N	Y
Permanent Meshing of Networks		
Meshing EHV Networks	N	Y
Meshing HV Networks	N	Y
Meshing LV Networks	N	Y
Inter-sector energy transfer		
Move from electricity to hydrogen	N	N
Move from hydrogen to electricity	N	N
Move from gas to electricity	N	N
Move from electricity to gas	N	N

For the avoidance of doubt, DNO congestion type tariffs, e.g. variable DUoS (Distribution Use of System [charging]) and CDCM (Common Distribution Charging Methodology) is out of scope of this model.

[76] "Temporary meshing" refers to running the network solid, utilising latent capacity, and relying on the use of automation to restore the network following a fault.

Table 13.4 Smart Solutions 1 costs and parameters

	Solution Headroom Impact						Costing		Merit Order Assessment									Dynamic Merit Stack	
Variant Solution - Smart	Thermal Transformer	Thermal Cable	Voltage Headroom	Voltage Legroom	Power Quality	Fault Level	Capex	Opex	Life expectancy	Totex	Cost Curve	Disruption Rating	Cross Network Benefits Rating	Flexibility Rating	Disruption Cost	Cross Network Benefits	Flexibility	2012 Merit	2050 Merit
Active Network Management - Dynamic Network Reconfiguration - EHV	10%	30%	2%	2%	5%	0%	£ 40,000	£ 500	20	£47,106	2	2	1	3	£2,500	-£5,000	90%	£ 2,007	£ 2,007
Active Network Management - Dynamic Network Reconfiguration - HV	10%	30%	3%	3%	5%	0%	£ 50,000	£ 250	20	£53,553	2	2	1	3	£2,500	-£5,000	90%	£ 2,297	£ 2,297
Active Network Management - Dynamic Network Reconfiguration - LV	5%	10%	3%	5%	5%	0%	£ 15,000	£ 100	20	£16,421	2	2	1	3	£2,500	-£5,000	90%	£ 626	£ 626
D-FACTS - EHV connected STATCOM	5%	10%	10%	10%	20%	5%	£ 250,000	£ 200	40	£254,271	3	3	1	2	£10,000	-£5,000	95%	£ 6,158	£ 4,445
D-FACTS - HV connected STATCOM	5%	10%	12%	12%	20%	5%	£ 150,000	£ 200	40	£154,271	3	3	2	2	£10,000	-£10,000	95%	£ 3,664	£ 2,625
D-FACTS - LV connected STATCOM	5%	10%	15%	15%	20%	5%	£ 30,000	£ 100	40	£32,136	3	3	1	2	£10,000	-£5,000	95%	£ 882	£ 665
Distribution Flexible AC Transmission Systems (D-FACTS) - EHV	4%	8%	8%	8%	20%	5%	£ 200,000	£ 200	40	£204,271	3	3	1	2	£10,000	-£5,000	95%	£ 4,970	£ 3,594
Distribution Flexible AC Transmission Systems (D-FACTS) - HV	4%	8%	8%	8%	20%	5%	£ 100,000	£ 200	40	£104,271	3	3	1	2	£10,000	-£5,000	95%	£ 2,595	£ 1,893
Distribution Flexible AC Transmission Systems (D-FACTS) - LV	4%	8%	8%	8%	20%	5%	£ 35,000	£ 100	40	£37,136	3	3	1	2	£10,000	-£5,000	95%	£ 1,001	£ 751
DSR_DNO to Central business District DSR	5%	10%	0%	3%	0%	0%	£ 10,000	£ 500	5	£12,258	2	3	2	3	£10,000	-£10,000	90%	£ 2,206	£ 2,206
DSR - DNO to residential	0%	0%	0%	0%	0%	0%	£ 1,000	£ 100	5	£1,452	2	5	2	4	£100,000	-£10,000	85%	£ 15,547	£ 15,547
DSR_DNO to aggregetor led EHV connected commercial DSR	5%	10%	0%	2%	0%	0%	£ 20,000	£200,000	5	£923,010	2	3	2	3	£10,000	-£10,000	90%	£166,142	£166,142
DSR_DNO to EHV connected commercial DSR	3%	5%	0%	1%	0%	0%	£ 5,000	£ 35,000	5	£163,027	2	2	2	3	£2,500	-£10,000	90%	£ 27,995	£ 27,995
DSR_DNO to aggregetor led HV commercial DSR	5%	10%	0%	2%	0%	0%	£ 15,000	£ 50,000	5	£240,753	2	4	-2	3	£30,000	£20,000	90%	£ 52,335	£ 52,335
DSR_DNO to HV commercial DSR	3%	5%	0%	1%	0%	0%	£ 5,000	£ 20,000	5	£95,301	2	4	3	3	£30,000	-£50,000	90%	£ 13,554	£ 13,554
Electrical Energy Storage_HV Central Business District (commercial building level)	5%	10%	0%	2%	0%	-5%	£ 10,000	£250,000	5	£1,138,763	3	3	2	3	£10,000	-£10,000	90%	£204,977	£146,834
Electrical Energy Storage_EHV connected EES - large	0%	0%	0%	0%	0%	-10%	£16,800,000	£ 500	20	£16,807,106	3	3	2	2	£10,000	-£10,000	95%	£798,338	£571,882
Electrical Energy Storage_EHV connected EES - medium	0%	0%	0%	0%	0%	-8%	£15,200,000	£ 500	20	£15,207,106	3	3	2	2	£10,000	-£10,000	95%	£722,338	£517,440
Electrical Energy Storage_EHV connected EES - small	0%	0%	0%	0%	0%	-5%	£13,600,000	£ 500	20	£13,607,106	3	3	2	2	£10,000	-£10,000	95%	£646,338	£462,998
Electrical Energy Storage_HV connected EES - large	0%	0%	0%	0%	0%	-10%	£ 4,200,000	£ 250	20	£4,203,553	3	3	2	2	£10,000	-£10,000	95%	£199,669	£143,031
Electrical Energy Storage_HV connected EES - medium	0%	0%	0%	0%	0%	-8%	£ 3,800,000	£ 250	20	£3,803,553	3	3	2	2	£10,000	-£10,000	95%	£180,669	£129,420
Electrical Energy Storage_HV connected EES - small	0%	0%	0%	0%	0%	-5%	£ 3,400,000	£ 250	20	£3,403,553	3	3	2	3	£10,000	-£10,000	90%	£153,160	£109,715
Electrical Energy Storage_LV connected EES - large	0%	0%	0%	0%	0%	-10%	£ 350,000	£ 250	20	£353,553	4	2	2	3	£2,500	-£10,000	90%	£ 15,572	£ 6,546
Electrical Energy Storage_LV connected EES - medium	0%	0%	0%	0%	0%	-8%	£ 300,000	£ 100	20	£301,421	4	2	2	3	£2,500	-£10,000	90%	£ 13,226	£ 5,531
Electrical Energy Storage_LV connected EES - small	0%	0%	0%	0%	0%	-5%	£ 250,000	£ 50	20	£250,711	4	2	2	4	£2,500	-£10,000	85%	£ 10,336	£ 4,292
Embedded DC Networks_Embedded DC@EHV	0%	40%	2%	2%	50%	50%	£ 500,000	£ 10,000	40	£713,551	2	3	1	2	£10,000	-£5,000	95%	£ 17,066	£ 17,066
Embedded DC Networks_Embedded DC@HV	0%	30%	5%	5%	50%	50%	£ 250,000	£ 5,000	40	£356,775	2	3	1	2	£10,000	-£5,000	95%	£ 8,592	£ 8,592
Embedded DC Networks_Embedded DC@LV	0%	20%	10%	10%	50%	50%	£ 125,000	£ 500	30	£134,196	2	3	1	2	£10,000	-£5,000	95%	£ 4,408	£ 4,408

Table 13.5 Smart Solutions 2 costs and parameters

Variant Solution - Smart	Solution Headroom Impact						Costing		Merit Order Assessment									Dynamic Merit Stack	
	Thermal Transformer	Thermal Cable	Voltage Headroom	Voltage Legroom	Power Quality	Fault Level	Capex	Opex	Life expectancy	Totex	Cost Curve	Disruption Rating	Cross Network Benefits Rating	Flexibility Rating	Disruption Cost	Cross Network Benefits	Flexibility	2012 Merit	2050 Merit
EAVC - HV/LV Transformer Voltage Control	0%	0%	15%	15%	0%	0%	£ 25,000	£ -	40	£25,000	2	3	1	2	£10,000	-£5,000	95%	£ 713	£ 713
EAVC - EHV circuit voltage regulators	0%	0%	6%	6%	0%	0%	£ 30,000	£ -	20	£30,000	2	2	1	4	£2,500	-£5,000	85%	£ 1,169	£ 1,169
EAVC - HV circuit voltage regulators	0%	0%	6%	6%	0%	0%	£ 20,000	£ -	20	£20,000	2	2	1	4	£2,500	-£5,000	85%	£ 744	£ 744
EAVC - LV circuit voltage regulators	0%	0%	10%	10%	0%	0%	£ 12,000	£ -	20	£12,000	2	2	1	4	£2,500	-£5,000	85%	£ 404	£ 404
EAVC - LV PoC voltage regulators	0%	0%	2%	2%	0%	0%	£ 2,000	£ 50	15	£2,576	2	2	0	4	£2,500	£0	85%	£ 288	£ 288
Fault Current Limiters_EHV Non-superconducting fault current limiters	0%	0%	0%	0%	0%	40%	£ 750,000	£ 200	25	£753,296	3	3	0	2	£10,000	£0	95%	£ 29,005	£ 20,885
Fault Current Limiters_EHV Superconducting fault current limiters	0%	0%	0%	0%	10%	50%	£ 750,000	£ 200	25	£753,296	3	3	0	2	£10,000	£0	95%	£ 29,005	£ 20,885
Fault Current Limiters_HV reactors - mid circuit	0%	0%	0%	0%	-10%	20%	£ 50,000	£ 100	45	£52,250	2	3	0	2	£10,000	£0	95%	£ 1,314	£ 1,314
Fault Current Limiters_HV Non-superconducting fault current limiters	0%	0%	0%	0%	0%	40%	£ 500,000	£ 200	25	£503,296	4	3	0	2	£10,000	£0	95%	£ 19,505	£ 8,655
Fault Current Limiters_HV Superconducting fault current limiters	0%	0%	0%	0%	10%	50%	£ 500,000	£ 200	25	£503,296	4	3	0	2	£10,000	£0	95%	£ 19,505	£ 8,655
Generator Constraint Management GSR - EHV connected generation	0%	0%	2%	0%	0%	0%	£ 150,000	£ 5,000	5	£172,575	2	0	0	0	£0	£0	100%	£ 34,515	£ 34,515
Generator Constraint Management GSR - HV connected generation	0%	0%	4%	0%	0%	0%	£ 80,000	£ 2,000	5	£89,030	2	0	0	0	£0	£0	100%	£ 17,806	£ 17,806
Generator Constraint Management GSR - LV connected generation	0%	0%	6%	0%	0%	0%	£ 20,000	£ 500	5	£22,258	2	0	0	0	£0	£0	100%	£ 4,452	£ 4,452
Generator Providing Network Support e.g. Operating in PV Mode - EHV	0%	0%	2%	2%	0%	0%	£ 15,000	£ 10,000	5	£60,151	2	0	0	0	£0	£0	100%	£ 12,030	£ 12,030
Generator Providing Network Support e.g. Operating in PV Mode - HV	0%	0%	4%	4%	0%	0%	£ 10,000	£ 5,000	5	£32,575	2	0	0	0	£0	£0	100%	£ 6,515	£ 6,515
Generator Providing Network Support e.g. Operating in PV Mode - LV	0%	0%	4%	4%	0%	0%	£ 2,000	£ 1,000	5	£6,515	2	0	0	0	£0	£0	100%	£ 1,303	£ 1,303
Local smart EV charging infrastructure_Intelligent control devices	5%	10%	0%	5%	0%	0%	£ 15,000	£ 250	25	£19,120	4	2	1	4	£2,500	-£5,000	85%	£ 565	£ 196
New Types Of Circuit Infrastructure_Novel EHV tower and insulator structures	0%	150%	0%	2%	0%	0%	£ 900,000	£ -	20	£900,000	2	5	1	1	£100,000	-£5,000	100%	£ 49,750	£ 49,750
New Types Of Circuit Infrastructure_Novel EHV underground cable	0%	150%	0%	2%	0%	0%	£ 900,000	£ -	20	£900,000	2	5	1	1	£100,000	-£5,000	100%	£ 49,750	£ 49,750
New Types Of Circuit Infrastructure_Novel HV tower and insulator structures	0%	150%	0%	3%	0%	0%	£ 600,000	£ -	20	£600,000	2	4	1	1	£30,000	-£5,000	100%	£ 31,250	£ 31,250
New Types Of Circuit Infrastructure_Novel HV underground cable	0%	150%	0%	3%	0%	0%	£ 300,000	£ -	20	£300,000	2	4	1	1	£30,000	-£5,000	100%	£ 16,250	£ 16,250
Permanent Meshing of Networks - EHV	25%	50%	0%	1%	30%	-33%	£ 30,000	£ 200	45	£34,499	2	3	-1	2	£10,000	£10,000	95%	£ 1,151	£ 1,151
Permanent Meshing of Networks - HV	15%	50%	0%	2%	20%	-33%	£ 100,000	£ 100	45	£102,250	2	3	-1	2	£10,000	£10,000	95%	£ 2,581	£ 2,581
Permanent Meshing of Networks - LV Urban	10%	50%	0%	2%	20%	-33%	£ 20,000	£ 100	45	£22,250	2	2	-1	2	£2,500	£10,000	95%	£ 734	£ 734
Permanent Meshing of Networks - LV Sub-Urban	5%	50%	0%	2%	20%	-33%	£ 20,000	£ 100	45	£22,250	2	2	-1	2	£2,500	£10,000	95%	£ 734	£ 734
RTTR for EHV Overhead Lines	0%	30%	0%	0%	0%	0%	£ 13,280	£ -	15	£13,280	3	2	0	4	£2,500	£0	85%	£ 894	£ 681
RTTR for EHV Underground Cables	0%	10%	0%	0%	0%	0%	£ 49,800	£ -	15	£49,800	3	2	0	4	£2,500	£0	85%	£ 2,964	£ 2,163
RTTR for EHV/HV transformers	10%	0%	0%	0%	0%	0%	£ 3,000	£ -	40	£3,000	3	2	0	4	£2,500	£0	85%	£ 117	£ 99
RTTR for HV Overhead Lines	0%	30%	0%	0%	0%	0%	£ 6,640	£ -	15	£6,640	3	2	0	4	£2,500	£0	85%	£ 518	£ 411
RTTR for HV Underground Cables	0%	10%	0%	0%	0%	0%	£ 24,900	£ -	15	£24,900	3	2	0	4	£2,500	£0	85%	£ 1,553	£ 1,152
RTTR for HV/LV transformers	10%	0%	0%	0%	0%	0%	£ 4,980	£ -	20	£4,980	3	2	0	4	£2,500	£0	85%	£ 318	£ 258
RTTR for LV Overhead Lines	0%	20%	0%	0%	0%	0%	£ 4,980	£ -	15	£4,980	3	2	0	4	£2,500	£0	85%	£ 424	£ 344
RTTR for LV Underground Cables	0%	8%	0%	0%	0%	0%	£ 16,600	£ -	15	£16,600	3	2	0	4	£2,500	£0	85%	£ 1,082	£ 816
Switched capacitors - EHV	0%	0%	10%	10%	10%	0%	£ 830,000	£ 150	30	£832,759	2	3	1	2	£10,000	-£5,000	95%	£ 26,529	£ 26,529
Switched capacitors - HV	0%	0%	6%	6%	10%	0%	£ 300,000	£ 50	30	£300,920	2	2	1	2	£2,500	-£5,000	95%	£ 9,450	£ 9,450
Switched capacitors - LV	0%	0%	5%	5%	10%	0%	£ 50,000	£ 10	30	£50,184	2	2	1	2	£2,500	-£5,000	95%	£ 1,510	£ 1,510
Temporary Meshing (soft open point) - EHV	10%	50%	0%	1%	10%	-33%	£ 20,000	£ 500	25	£28,241	2	1	0	4	£0	£0	85%	£ 960	£ 960
Temporary Meshing (soft open point) - HV	8%	50%	0%	2%	10%	-33%	£ 20,000	£ 500	25	£28,241	2	2	0	4	£2,500	£0	85%	£ 1,045	£ 1,045
Temporary Meshing (soft open point) - LV	5%	50%	0%	2%	10%	-33%	£ 20,000	£ 100	25	£21,648	3	2	0	4	£2,500	£0	85%	£ 821	£ 612

Table 13.6 Size and energy capacity of electrical energy storage solutions within the WS3 model

	Storage(kW)	Storage(kWh)
Electrical Energy Storage_HV Central Business District (commercial building level)	500	1,000
Electrical Energy Storage_EHV connected EES - large	15,000	30,000
Electrical Energy Storage_EHV connected EES - medium	12,500	25,000
Electrical Energy Storage_EHV connected EES - small	7,500	15,000
Electrical Energy Storage_HV connected EES - large	3,000	6,000
Electrical Energy Storage_HV connected EES - medium	2,500	5,000
Electrical Energy Storage_HV connected EES - small	1,500	3,000
Electrical Energy Storage_LV connected EES - large	100	200
Electrical Energy Storage_LV connected EES - medium	75	150
Electrical Energy Storage_LV connected EES - small	50	100

13.1.4 Mapping Enablers to Smart Solutions

The enablers that are required to facilitate a smart solution are listed in the model against the respective solution, and shown on the following two pages.

It should be noted that for the solution to function effectively, all of the named enablers must be present; therefore when selecting the solution the model also deploys the necessary enablers (unless this has already been done via a top-down investment). There are some enablers that are not currently used by the model (when using the incremental investment strategy). Examples of these included enablers concerned with monitoring waveform quality, as the model (in its present form) does not consider power quality issues. However, there are several enablers that could be regarded as being alternatives. For example, it is possible to install “LV circuit monitoring” or “LV circuit monitoring with state estimation”. Only the former of these is currently tagged against solutions where either of the techniques is valid to facilitate the solution. If the model were to tag both enablers, it would mean that both would have to be invested in such that the solution could operate (when in reality one or the other is required).

If a DNO were to decide to opt for state estimation, therefore, it would be necessary to change the tagging of the enablers to reflect this.

Table 13.7 Mapping of Enablers to Smart Solutions (for the Smart Incremental investment strategy) 1

	ENABLERS																													
SMART SOLUTIONS	Advanced control systems	Communications to and from devices	Design tools	DSR - Products to remotely control loads at consumer premises	DSR - Products to remotely control EV charging	EHV Circuit Monitoring	HV Circuit Monitoring (along feeder)	HV Circuit Monitoring (along feeder) w/ State Estimation	HV/LV Tx Monitoring	Link boxes fitted with remote control	LV Circuit Monitoring (along feeder)	LV Circuit monitoring (along feeder) w/ state estimation	LV feeder monitoring at distribution substation	LV feeder monitoring at distribution substation w/ state estimation	RMUs Fitted with Actuators	Communications to DSR aggregator	Dynamic Network Protection, 11kV	Weather monitoring	Monitoring waveform quiality (EHV/HV Tx)	Monitoring waveform quiality (HV/LV Tx)	Monitoring waveform quiality (HV feeder)	Monitoring waveform quiality (LV Feeder)	Smart Metering infrastructure - DCC to DNO 1 way	Smart Metering infrastructure -DNO to DCC 2 way A+D	Smart Metering infrastructure -DNO to DCC 2 way control	Phase imbalance - LV dist s/s	Phase imbalance - LV circuit	Phase imbalance -smart meter phase identification	Phase imbalance - LV connect customer, 3 phase	Phase imbalance -HV circuit
Active Network Management - Dynamic Network Reconfiguration - EHV	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE
Active Network Management - Dynamic Network Reconfiguration - HV	TRUE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	TRUE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE
Active Network Management - Dynamic Network Reconfiguration - LV	TRUE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	TRUE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE
D-FACTS - EHV connected STATCOM	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE
D-FACTS - HV connected STATCOM	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE
D-FACTS - LV connected STATCOM	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE
Distribution Flexible AC Transmission Systems (D-FACTS) - EHV	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE
Distribution Flexible AC Transmission Systems (D-FACTS) - HV	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE
Distribution Flexible AC Transmission Systems (D-FACTS) - LV	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE
DSR_DNO to Central business District DSR	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE
DSR - DNO to residential	FALSE	TRUE	FALSE	TRUE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE
DSR_DNO to aggregetor led EHV connected commercial DSR	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE
DSR_DNO to EHV connected commercial DSR	FALSE	TRUE	FALSE	TRUE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE
DSR_DNO to aggregetor led HV commercial DSR	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE
DSR_DNO to HV commercial DSR	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE
Electrical Energy Storage_HV Central Business District (commercial building level)	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE
Electrical Energy Storage_EHV connected EES - large	TRUE	TRUE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE
Electrical Energy Storage_EHV connected EES - medium	TRUE	TRUE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE
Electrical Energy Storage_EHV connected EES - small	TRUE	TRUE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE
Electrical Energy Storage_HV connected EES - large	TRUE	TRUE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE
Electrical Energy Storage_HV connected EES - medium	TRUE	TRUE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE
Electrical Energy Storage_HV connected EES - small	TRUE	TRUE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE
Electrical Energy Storage_LV connected EES - large	TRUE	TRUE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE
Electrical Energy Storage_LV connected EES - medium	TRUE	TRUE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE
Electrical Energy Storage_LV connected EES - small	TRUE	TRUE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE
Embedded DC Networks_Embedded DC@EHV	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE
Embedded DC Networks_Embedded DC@HV	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE
Embedded DC Networks_Embedded DC@LV	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE

Table 13.8 Mapping of Enablers to Smart Solutions (for the Smart Incremental investment strategy) 2

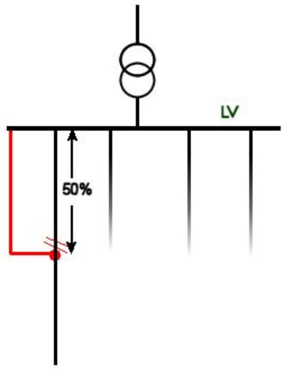
	ENABLERS																													
SMART SOLUTIONS	Advanced control systems	Communications to and from devices	Design tools	DSR - Products to remotely control loads at consumer premises	DSR - Products to remotely control EV charging	EHV Circuit Monitoring	HV Circuit Monitoring (along feeder)	HV Circuit Monitoring (along feeder) w/ State Estimation	HV/LV Tx Monitoring	Link boxes fitted with remote control	LV Circuit Monitoring (along feeder)	LV Circuit monitoring (along feeder) w/ state estimation	LV feeder monitoring at distribution substation	LV feeder monitoring at distribution substation w/ state estimation	RMUs Fitted with Actuators	Communications to DSR aggregator	Dynamic Network Protection, 11kV	Weather monitoring	Monitoring waveform quality (EHV/HV Tx)	Monitoring waveform quality (HV/LV Tx)	Monitoring waveform quality (HV feeder)	Monitoring waveform quality (LV Feeder)	Smart Metering infrastructure - DCC to DNO 1 way	Smart Metering infrastructure -DNO to DCC 2 way A+D	Smart Metering infrastructure -DNO to DCC 2 way control	Phase imbalance - LV dist s/s	Phase imbalance - LV circuit	Phase imbalance -smart meter phase identification	Phase imbalance - LV connect customer, 3 phase	Phase imbalance -HV circuit
EAVC - HV/LV Transformer Voltage Control	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	TRUE	FALSE	TRUE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE
EAVC - EHV circuit voltage regulators	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	TRUE	FALSE	TRUE	FALSE	TRUE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE
EAVC - HV circuit voltage regulators	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	TRUE	FALSE	TRUE	FALSE	TRUE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE
EAVC - LV circuit voltage regulators	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	TRUE	FALSE	TRUE	FALSE	TRUE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE
EAVC - LV PoC voltage regulators	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	TRUE	FALSE	TRUE	FALSE	TRUE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE
Fault Current Limiters_EHV Non-superconducting fault current limiters	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE
Fault Current Limiters_EHV Superconducting fault current limiters	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE
Fault Current Limiters_HV reactors - mid circuit	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE
Fault Current Limiters_HV Non-superconducting fault current limiters	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE
Fault Current Limiters_HV Superconducting fault current limiters	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE
Generator Constraint Management GSR - EHV connected generation	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE
Generator Constraint Management GSR - HV connected generation	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	TRUE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE
Generator Constraint Management GSR - LV connected generation	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	TRUE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE
Generator Providing Network Support e.g. Operating in PV Mode - EHV	FALSE	FALSE	FALSE	FALSE	FALSE	TRUE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE
Generator Providing Network Support e.g. Operating in PV Mode - HV	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	TRUE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE
Generator Providing Network Support e.g. Operating in PV Mode - LV	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	TRUE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE
Local smart EV charging infrastructure_Intelligent control devices	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE
New Types Of Circuit Infrastructure_Novel EHV tower and insulator structures	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE
New Types Of Circuit Infrastructure_Novel EHV underground cable	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE
New Types Of Circuit Infrastructure_Novel HV tower and insulator structures	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE
New Types Of Circuit Infrastructure_Novel HV underground cable	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE
Permanent Meshing of Networks - EHV	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE
Permanent Meshing of Networks - HV	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE
Permanent Meshing of Networks - LV Urban	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE
Permanent Meshing of Networks - LV Sub-Urban	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE
RTTR for EHV Overhead Lines	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE
RTTR for EHV Underground Cables	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	TRUE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE
RTTR for EHV/HV transformers	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	TRUE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE
RTTR for HV Overhead Lines	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	TRUE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE
RTTR for HV Underground Cables	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	TRUE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE
RTTR for HV/LV transformers	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	TRUE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE
RTTR for LV Overhead Lines	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	TRUE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE
RTTR for LV Underground Cables	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	TRUE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE
Switched capacitors - EHV	FALSE	FALSE	FALSE	FALSE	FALSE	TRUE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE
Switched capacitors - HV	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	TRUE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE
Switched capacitors - LV	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	TRUE	FALSE	TRUE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE
Temporary Meshing (soft open point) - EHV	TRUE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE
Temporary Meshing (soft open point) - HV	TRUE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE
Temporary Meshing (soft open point) - LV	TRUE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE

13.2 Conventional solutions

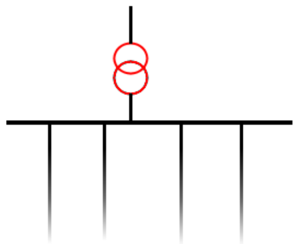
13.2.1 Overview

The following diagrams and explanations detail the solutions that are included where any coloured circuits or transformers indicate new assets provided by the solution. It should be noted that the diagrams refer to LV implementation of the solutions, but the solutions will also be applicable at HV and EHV as described in the accompanying text.

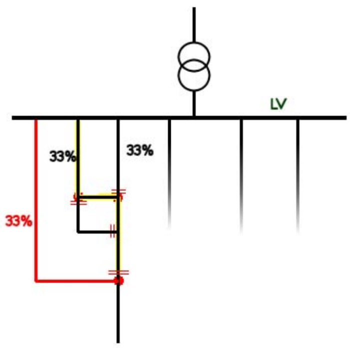
- **Split the feeder** i.e. transfer half of the load of the existing feeder onto a new feeder



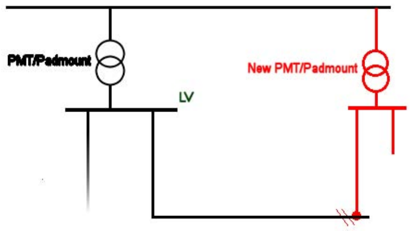
- **Replace the transformer**



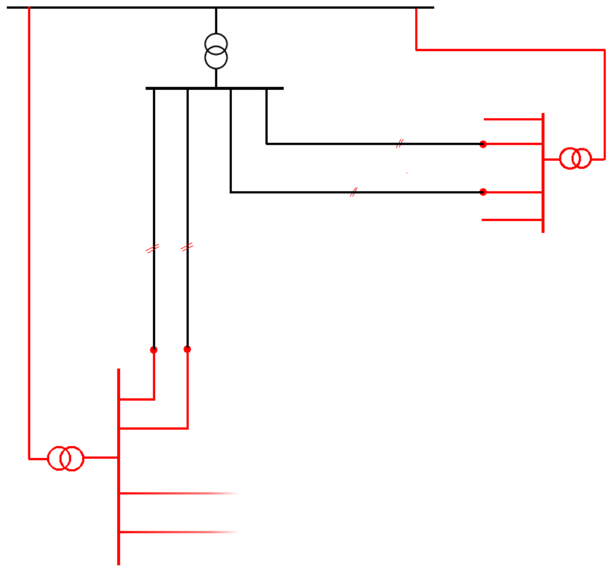
- **New split feeder** i.e. run a new feeder from the substation to the midpoint of the already split feeder and perform some cable jointing to further split the load, resulting in three feeders each having approximately equal loads). It should be noted that the total amount of cabling required to deliver this solution has been calculated to be equal to the cabling required to deliver the "split feeder" solution, but there is additional cross-jointing required meaning that the costs are slightly higher. The figures in the diagram of 33% represent the load that now exists on each feeder as against an unreinforced case, but are not representative of the relative cable lengths of each feeder.



- **Minor works** at LV this would involve the installation of a new pole mounted, pad mounted substation or second transformer at a pre-existing substation to take half of the load from the substation being reinforced but with limited HV cabling required, while at HV and EHV it will take the form of an additional transformer being installed at an existing site.



- **Major works** at LV this would involve the construction of new distribution substations with associated LV cabling to integrate these substations into the heavily loaded network, and also some HV cabling to allow the new substations to be fed from the relevant primary substations; at higher voltages the principle is the same, with the construction of a new primary substation or bulk supply point and associated cabling.



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 the first three solutions listed 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 splitting of feeders and replacement of transformers, there is also the option for minor and major work at LV, HV and EHV. These options allow for the cases where more significant investment is needed for portions of the network that have undergone significant periods of load growth.

The costs associated with these options do not come directly from DPCR5 figures, but have been agreed with the Network Operators as being reasonable in facilitating 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 are all assumed to be 40 years in the model.

The costs of the various solutions and the other parameters associated with them are summarised in the table below. It should be noted that these costs are calculated on a per feeder basis, meaning that the cost of installing, for example, a primary transformer is smeared across the number of feeders that the transformer supplies. This is then applied in the model by having cost functions which bias the costs over time for different reinforcements meaning that a transformer is not paid for more than once, but equally meaning that the total amount of investment required is more appropriately captured (i.e. it is not shown that a DNO would only need to invest in 25% of a transformer to solve a problem as, clearly, the DNO would need to bear the costs of the entire transformer as part of a reinforcement scheme).

These costs are listed for existing network areas that are being invested in, rather than for new “greenfield” sites. It is envisaged that alternative costs will be available for greenfield developments which will be some 20% lower to represent the reduced levels of difficulty in installing circuits and obtaining any extensions to existing wayleave agreements, or other land constraints.

Table 13.9 Conventional Solutions costs and parameters

Variant Solution - Conventional	Solution Headroom Impact						Costing		Merit Order Assessment											Dynamic Merit Stack	
	Thermal Transformer	Thermal Cable	Voltage Headroom	Voltage Legroom	Power Quality	Fault Level	Capex	Opex	Life expectancy	Totex	Cost Curve	Disruption Rating	Cross Network Benefits Rating	Flexibility Rating	Disruption Cost	Cross Network Benefits	Flexibility	Total Additions	Total Multiplier	2012 Merit	2050 Merit
LV Underground network Split feeder	0%	100%	1%	3%	0%	0%	£ 30,000	£-	40	£30,000	1	4	0	1	£30,000	£0	100%	£30,000	3%	£ 1,500	£ 1,661
LV New Split feeder	0%	80%	1%	2%	0%	0%	£ 33,000	£-	40	£33,000	1	4	0	1	£30,000	£0	100%	£30,000	3%	£ 1,575	£ 1,752
LV Ground mounted 11/LV Tx	80%	0%	1%	6%	0%	-10%	£ 3,432	£-	40	£3,432	1	4	0	2	£30,000	£0	95%	£30,000	2%	£ 794	£ 812
LV underground Minor works	100%	100%	1%	10%	0%	-15%	£ 80,000	£-	40	£80,000	1	4	0	1	£30,000	£0	100%	£30,000	3%	£ 2,750	£ 3,179
LV underground Major works	500%	500%	1%	15%	0%	-20%	£ 250,000	£-	40	£250,000	1	4	0	1	£30,000	£0	100%	£30,000	3%	£ 7,000	£ 8,341
LV overhead network Split feeder	0%	100%	1%	3%	0%	0%	£ 10,000	£-	40	£10,000	1	4	0	1	£30,000	£0	100%	£30,000	3%	£ 1,000	£ 1,054
LV overhead network New Split feeder	0%	80%	1%	2%	0%	0%	£ 11,000	£-	40	£11,000	1	4	0	1	£30,000	£0	100%	£30,000	3%	£ 1,025	£ 1,084
LV Pole mounted 11/LV Tx	80%	0%	1%	6%	0%	-10%	£ 1,450	£-	40	£1,450	1	4	0	2	£30,000	£0	95%	£30,000	2%	£ 747	£ 754
LV overhead Minor works	100%	100%	1%	10%	0%	-15%	£ 20,000	£-	40	£20,000	1	4	0	1	£30,000	£0	100%	£30,000	3%	£ 1,250	£ 1,357
LV overhead Major works	500%	500%	1%	15%	0%	-20%	£ 125,000	£-	40	£125,000	1	4	0	1	£30,000	£0	100%	£30,000	3%	£ 3,875	£ 4,546
HV underground network Split feeder	0%	100%	1%	2%	0%	0%	£ 217,600	£-	40	£217,600	1	5	0	1	£100,000	£0	100%	£100,000	3%	£ 7,940	£ 9,108
HV underground New Split feeder	0%	80%	1%	1%	0%	0%	£ 239,360	£-	40	£239,360	1	5	0	1	£100,000	£0	100%	£100,000	3%	£ 8,484	£ 9,768
Large 33/11 Tx	80%	0%	1%	4%	0%	-10%	£ 86,667	£-	40	£86,667	1	5	0	2	£100,000	£0	95%	£100,000	2%	£ 4,433	£ 4,875
HV underground Minor works	100%	100%	1%	6%	0%	-15%	£ 450,000	£-	40	£450,000	1	5	0	1	£100,000	£0	100%	£100,000	3%	£ 13,750	£ 16,164
HV underground Major works	500%	500%	1%	12%	0%	-20%	£1,500,000	£-	40	£1,500,000	1	5	0	1	£100,000	£0	100%	£100,000	3%	£ 40,000	£ 48,048
HV overhead network Split feeder	0%	100%	1%	2%	0%	0%	£ 315,000	£-	40	£315,000	1	4	0	1	£30,000	£0	100%	£30,000	3%	£ 8,625	£ 10,315
HV overhead New Split feeder	0%	80%	1%	1%	0%	0%	£ 346,500	£-	40	£346,500	1	4	0	1	£30,000	£0	100%	£30,000	3%	£ 9,413	£ 11,272
Small 33/11 Tx	80%	0%	1%	4%	0%	-10%	£ 97,500	£-	40	£97,500	1	4	0	2	£30,000	£0	95%	£30,000	2%	£ 3,028	£ 3,525
HV overhead Minor works	100%	100%	1%	6%	0%	-15%	£ 500,000	£-	40	£500,000	1	5	0	1	£100,000	£0	100%	£100,000	3%	£ 15,000	£ 17,683
HV overhead Major works	500%	500%	1%	12%	0%	-20%	£ 900,000	£-	40	£900,000	1	5	0	1	£100,000	£0	100%	£100,000	3%	£ 25,000	£ 29,829
EHV underground network Split feeder	0%	100%	1%	2%	0%	0%	£ 622,600	£-	40	£622,600	1	5	0	1	£100,000	£0	100%	£100,000	3%	£ 18,065	£ 21,406
EHV underground New Split feeder	0%	80%	1%	1%	0%	0%	£ 684,860	£-	40	£684,860	1	5	0	1	£100,000	£0	100%	£100,000	3%	£ 19,622	£ 23,296
EHV underground Minor works	100%	100%	1%	3%	0%	-15%	£1,200,000	£-	40	£1,200,000	1	5	0	1	£100,000	£0	100%	£100,000	3%	£ 32,500	£ 38,939
EHV underground Major works	500%	500%	1%	6%	0%	-20%	£5,000,000	£-	40	£5,000,000	1	5	0	1	£100,000	£0	100%	£100,000	3%	£127,500	£154,328
EHV overhead network Split feeder	0%	100%	1%	2%	0%	0%	£ 600,000	£-	40	£600,000	1	5	0	1	£100,000	£0	100%	£100,000	3%	£ 17,500	£ 20,719
EHV overhead New Split feeder	0%	80%	1%	1%	0%	0%	£ 660,000	£-	40	£660,000	1	5	0	1	£100,000	£0	100%	£100,000	3%	£ 19,000	£ 22,541
EHV overhead Minor works	100%	100%	1%	3%	0%	-15%	£1,000,000	£-	40	£1,000,000	1	5	0	1	£100,000	£0	100%	£100,000	3%	£ 27,500	£ 32,866
EHV overhead Major works	500%	500%	1%	6%	0%	-20%	£3,000,000	£-	40	£3,000,000	1	5	0	1	£100,000	£0	100%	£100,000	3%	£ 77,500	£ 93,597

13.3 Assigning Parameters to the Solutions and Enablers

13.3.1 Solution Costs

Table 13.10 Solution costs

Capital (£)	The capital cost of procuring and installing the solution. This cost does not include the costs of associated enablers such as monitoring.
Operational Expenditure (£)	The annual estimated opex cost of the solution. NB. This figure is then converted into an NPV equivalent, which is combined with the capital costs to form a cost of deployment.
Cost Curve Type	The cost curve applied to model the future change in cost of the solution based on time and volume. In summary these are: 1. Rising (120% of original cost after 30yrs) 2. Flat (100% original cost after 30yrs) 3. Shallow reduction (75% of original cost after 30yrs) 4. Medium reduction (50% of original cost after 30yrs) 5. High reduction (20% of original cost after 30yrs) See the end of this Appendix for further details and supporting evidence on the cost curves.
Life Expectancy of Solution	Expected life of the solution in years.

All costs in the following tables (and supporting Annex) do not include optimism bias.

13.3.2 Cost Function Parameters

Table 13.11 Disruption Factor Attributes

Disruption Factor	Impact on public	Description	Example Solution	Estimate of disruption cost (per solution deployment)
1	Very Low	• Installation of equipment in a Network Operators' substation. • No need for outages or network reconfiguration to connect and commission solution	• Substation communications • Network monitoring devices	£0k
2	Low	• Installation of equipment in a Network Operators' substation or on their circuits. • Network reconfiguration necessary in order to connect / commission solution. • No requirements to purchase new substation land or obtain new wayleaves	• Enhanced forms of Voltage Control relay(s) • Non-intrusive real time thermal rating kit	£0k - £5k [Set as £2.5k in the model]
3	Moderate	• Installation of equipment in a 3rd party substation or on a Network Operators' overhead line / underground cable network • Limited (<100kW) customer supply disconnection necessary in order to connect / commission solution • New land purchases necessary (e.g. adjacent to an existing substation) • New easement / wayleaves required, though not widespread (e.g. 1-2 landowners)	• Substation located electrical energy storage, SVCs, etc. • Large scale pole mounted equipment (e.g. voltage regulators) • Industrial / aggregator led DSR	£5k - £20k [Set as £10k in the model]
4	High	• New wayleaves or easements essential with several landowners (2-5) to facilitate solution. • Small / short term disruption to transport under the Road Traffic Act. • Supply (100kW-1MW) disconnection necessary to connect / commission solution.	• New LV circuits / smaller sections of HV circuit • New underground cable / overhead lines • Community / village level DSR (via DNO and/or Energy Suppliers)	£20k - £50k [Set as £30k in the model]
5	Very High	• Active public consultation / engagement required with long lead times in order to facilitate solution • Consensus of multiple landowners necessary (5+) • Significant disruption to transport (cars, trains, airports) • Significant (>1MW) supply disconnection necessary to connect / commission solution. • Derogations from legal / licence obligations	• New ENV or large HV circuits • Town/ suburb level DSR (via DNO and/or Energy Suppliers)	£50k+ [Set as £100k in the model]

Table 13.12 Cross Network Benefits Factor attributes

#	Cross Network Benefits	Description	Example Solution	Initial (merit) Cost
-2	Moderate Reduction	20 to 50% reduction in Headroom at a higher or lower voltage level	• Placeholder – no examples known	£20k
-1	Slight Reduction	0 to 20% reduction in Headroom at a higher or lower voltage level	• Permanent meshing: whilst meshing uses the latent capacity of feeders through higher network utilisation, the load may be transferred from one feeder to another, which may lead to a small reduction in rating at higher voltages	£10k
0	None	Solutions which only have benefits on the network to which they are deployed	• Fault current limiters	0
1	Low Improve-ment	0 to 20% increase in Headroom at a higher or lower voltage level	• Small LV connected battery storage units • Point of connection voltage control units (e.g. LV regulators on a domestic customers property), but may give some ability to relax the voltage control at HV • Switched capacitor, D-FACTS, STATCOM type units where the devices have an ability to inject VArs for network support • HV Generation Constraint Management	-£5k
2	Medium Improve-ment	20 to 50% increase in Headroom at a higher or lower voltage level	• Large scale (HV or aggregated LV) electrical energy storage units, that could change the profiles of downstream demands	-£10k
3	High Improve-ment	>50% increase in Headroom at a higher or lower voltage level	• Widescale aggregated domestic demand response – has the ability to change the demand profiles at LV, which in turn will affect the demands placed on the HV and EHV networks	-£50k

Table 13.13 Flexibility factor attributes

#	Flexibility	Description	Example Solution	Merit Factor
1	Low	A permanent fixed asset, unable to be redeployed	• underground cable	x 1.0
2	Low-Medium	A fixed asset that can be redeployed, but with significant cost	• transformer, • HV storage unit, • EHV D-FACTS device	x 0.95
3	Medium	A smaller fixed asset, that could be moved within the life of the asset	• LV battery storage, • HV in-line voltage regulator	x 0.9
4	Medium-High	A component or control type solution that could be readily redeployed	• Power donut on HV or EHV overhead line	x 0.85
5	High	A portable device able to be redeployed with minimal time or operational expenditure	• Clip- current transformer or monitoring device in a DNOs substation	x 0.8

13.3.3 Other Parameters

Impact on	Estimated impact on fixed losses such as transformer iron loss, storage unit

Fixed Losses (%)	running losses in real terms as a percentage of that network loss
Impact on Variable Losses (%)	Estimated percentage impact on copper losses on a given network A negative figure would indicate an improvement (reduction) in losses; a positive figure would indicate an increase in losses. Many 'smart solutions' can have a detrimental impact on technical losses, for example the use of dynamic line rating (where the line rating is increased from 100% to 130%), could increase losses by as much as 69% (due to the squared relationship between current and copper losses) if running at full rating continuously
Impact on quality of supply (%)	Estimated percentage impact on CI/CMLs A positive figure would indicate an improvement in Supply Quality; a negative figure would indicate a reduction in Supply Quality (on the base case)
Year when solution becomes available	Some smart solutions are unavailable at present - this field allows for a year to be specified from when the solution can be deployed
Year when data on the solution is available	In order to validate the headroom release figures, some data from trial implementations may be required; this field allows a year when such (improved) data becomes available to be entered
Source of Data	Details on where the data is being provided from, e.g. a specific Tier 1 or Tier 2 Low Carbon Network Fund project

13.4 Further information to support the use of cost curves

13.4.1 Overview

The cost of solutions is key to comparing smart and conventional solutions within the WS3 model. Each solution has costs entered against it and must be modeled in the present and in the future. To this end, it is important to understand how the costs of technologies may change in the future. This paper presents the generic cost curves which have been produced to predict the changes in cost over time of solutions.

Five generic cost curves have been produced which represent the changing costs of different types of technology over time. The technologies that support our generic curves have been chosen as they combine different factors such as volume, material cost price changes and learning curves, from both within and out of the energy sector.

A cost curve will be associated with each solution in the model to allow the future costs of solutions to be approximated based on similar technologies.

The figure below shows the five generic cost curves on a single graph rebased to year zero and the year zero cost.

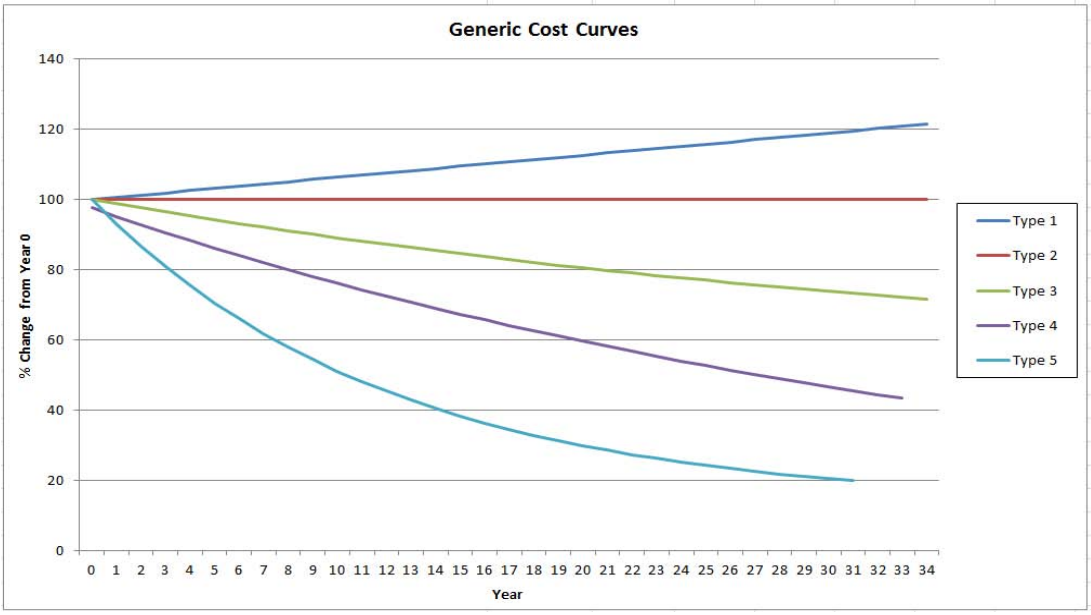


Figure 13.1 Graph showing all cost curves plotted together

The five cost curves have been derived from the curves shown on the proceeding pages and are made up as follows:

- Type 1; Rising (based on an average of the Steel and Aluminium cost curves)
- Type 2; Flat (to represent no change in cost)
- Type 3; Shallow reduction (based on an average of offshore wind farm costs and flat line)
- Type 4; Medium reduction (based on the cost curve for offshore wind farms)
- Type 5; High reduction (based on the cost curve for laptops)

Table 13.14 Equations to describe the five cost curves used within the WS3 model

Type	Equation
1	$0.6312x + 99.369$
2	x
3	$99.576e^{-0.01x}$
4	$99.915e^{-0.025x}$
5	$94.559e^{-0.053x}$

13.4.2 Supporting information to back up the cost curves

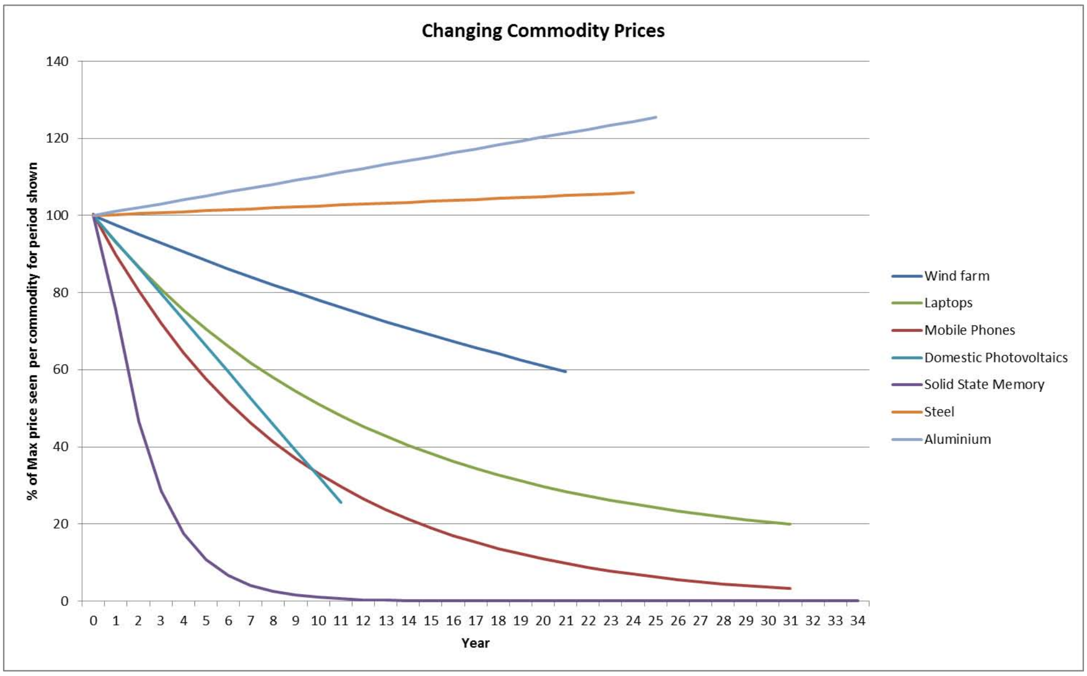


Figure 13.2 Cost curve - changing commodity prices

The graph above shows the all of the technology price curves together, rebased to start at year 0 and 100%. The technologies were chosen based on the following:

- Wind farms have seen big increases in installed capacity but have also met significant technical challenges in installation offshore. Whilst the volume of wind farms installed has increased significantly, the price reduction observed has been gradual and at times volatile due to the reliance on expensive materials.
- Laptops demonstrate a domestic product which has seen a large increase in popularity, especially as they have come to rival desktop computers in terms of price point, whilst not being an essential consumer product. Smart solutions which might follow a similar curve are solutions such as point of connection demand side response devices.
- Mobile Phones represent technologies which start off as niche products with massive potential for cost reductions and functional improvements as sales volumes increase and technology improves. Technologies which may follow similar curves are domestic products allowing for complete home energy management.

- Domestic Photovoltaics represent a technology which has become more attractive due to low carbon incentives such as FITs.
- Solid State Memory represents a technology which has seen massive volume increases, starting off as a very niche product with limited uses, solid state memory can now be found in almost every consumer electrical product.

13.4.2.1 Cost curve – aluminum

Description: Aluminum cost changes can be attributed to the following:

1. Extraction costs
2. Processing costs – high energy requirements
3. Transport costs
4. Materials, commodities and labour costs
5. Currency movements

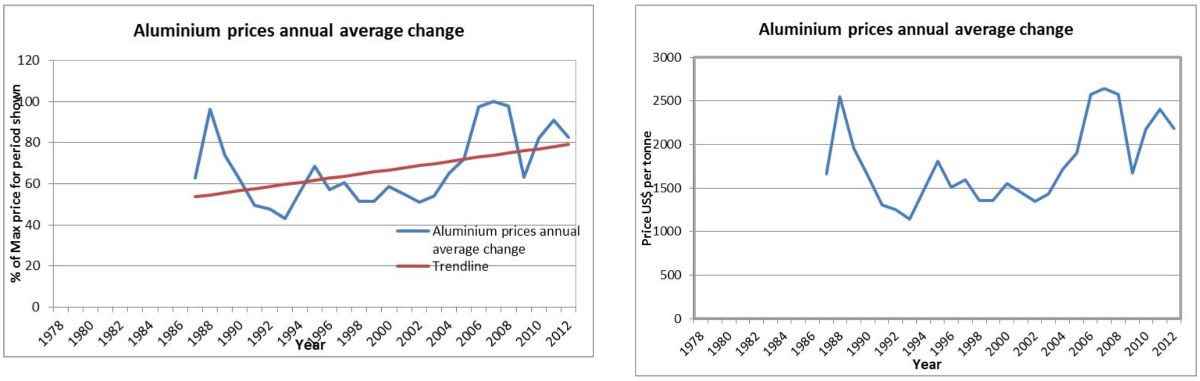


Figure 13.3 Cost curve – aluminium[77]

13.4.2.2 Cost curve – steel

Description: Steel cost changes can be attributed to the following:

1. Extraction costs
2. Processing costs – high energy requirements
3. Transport costs
4. Materials, commodities and labour costs
5. Currency movements

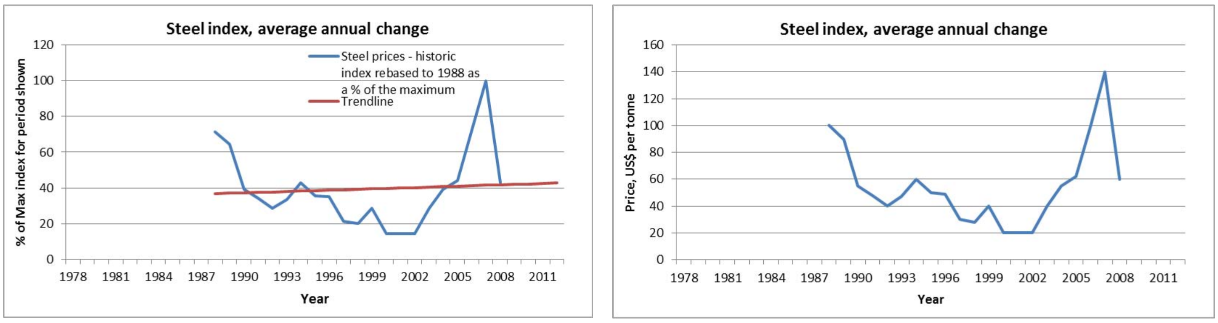


Figure 13.4 Cost curve – steel[78]

13.4.2.3 Cost curve – average offshore wind farm capex cost per MW

[77] Source of data; London Metal Exchange, http://www.lme.com/aluminium_graphs.asp accessed on 05.04.12.
[78] Source of data; London Metal Exchange, http://www.lme.com/steel/index.asp accessed on 05.04.12.

Description: Wind farm cost changes can be attributed to the following:

1. Innovation
2. Volume; economies of scale
3. Materials, commodities and labour costs
4. Currency movements
5. Increasing prices for turbines over and above the cost of materials, due to supply chain constraints, market conditions and engineering issues
6. Learning Curves; the increasing depth and distance of more ambitious projects, affecting installation, foundation and operation and maintenance (O&M) costs
7. Supply chain constraints, notably in vessels and ports
8. Planning and consenting delays

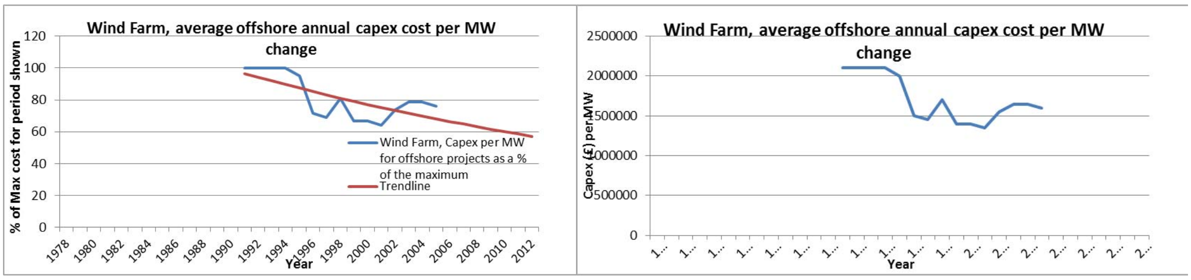


Figure 13.5 Cost curve – wind farm, average offshore annual capex cost per MW[79]

13.4.2.4 Cost curve – annual average laptop cost

Description: Laptop cost changes can be attributed to the following:

1. Innovation; smaller and faster processors, hard disc drives, memory and displays
2. Availability of off-the-shelf components due to common component manufacture
3. Volume – Moderate take-up rates as desktop PCs were widely preferred and cheaper
4. Materials, commodities and labour costs
5. Currency movements

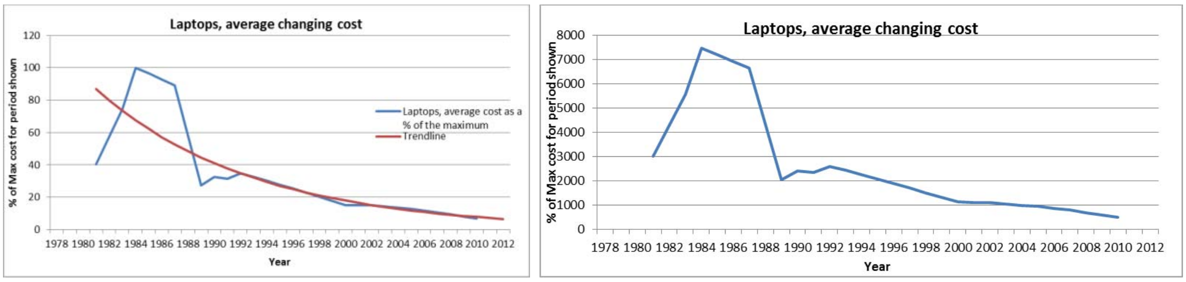


Figure 13.6 Cost curve – annual average laptop cost[80]

[79] Source of information; UKERC "Great Expectations: The cost of offshore wind in UK waters –understanding the past and projecting the future".
[80] Source of information; Online historical laptop research http://oldcomputers.net accessed on 02/04/12. All prices converted using average exchange rate for the year of manufacture (where appropriate) and adjusted for inflation.

13.4.2.5 Cost curve– annual average mobile 'phone cost

Description: Mobile 'phone cost changes can be attributed to the following:

1. Innovation; smaller and faster processors, memory and displays.
2. Availability of off-the-shelf components due to common component manufacture
3. Volume – rapid change, fast take-up niche product
4. Materials, commodities and labour costs
5. Currency movements

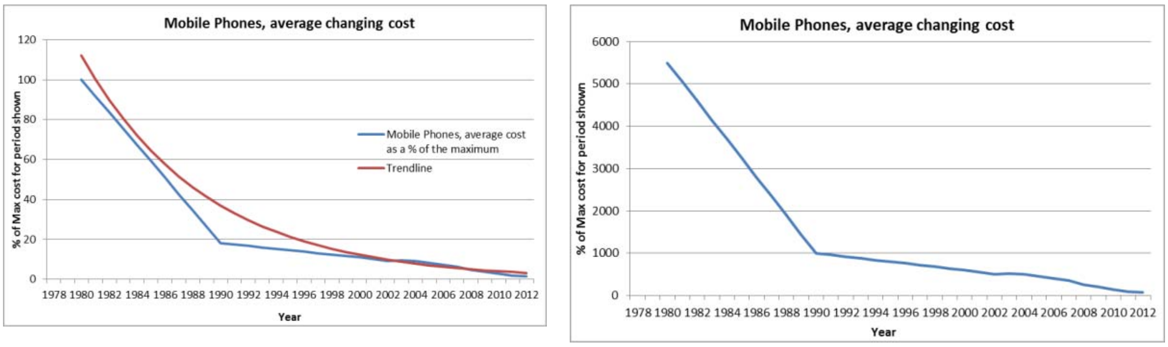


Figure 13.7 Cost curve – annual average mobile 'phone cost[81]

13.4.2.6 Cost curve– domestic photovoltaic peak costs per watt per annum

Description: Domestic PV cost changes can be attributed to the following:

1. Innovation, increased efficiency in solar energy conversion resulting in higher power densities
2. Learning curves; higher component yields in manufacture
3. Volume – Rapid take-up rate
4. Materials, commodities and labour costs
5. Currency movements

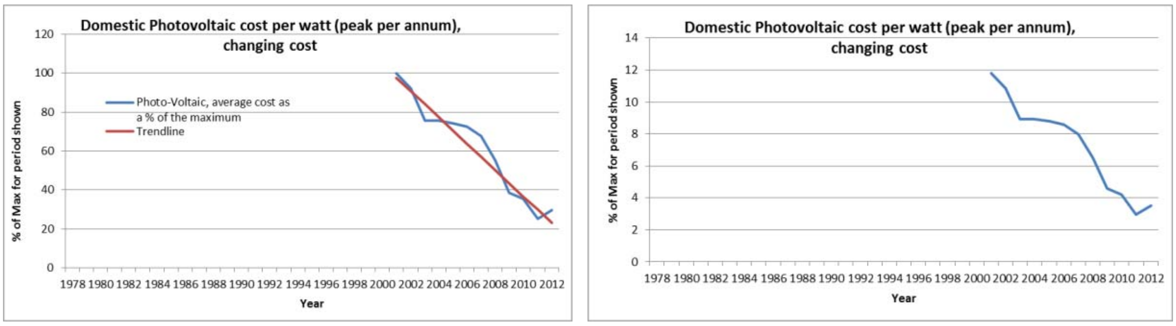


Figure 13.8 Cost curve – domestic photovoltaic peak costs per watt per annum[82]

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[81] Source of data; http://www.castlecover.co.uk/household-products/index.html accessed on 04.04.12. Prices adjusted for inflation.

[82] Source of data; http://www.solarbuzz.com/facts-and-figures/retail-price-environment/module-prices accessed on 03.04.12

13.4.2.7 Cost curve– Solid State Memory costs per Mega-Byte

Description: Solid State Memory cost changes can be attributed to the following:

1. Innovation, different techniques to increase capacity
2. Learning curves; higher component yields in manufacture
3. Volume – very rapid take-up as solid state memory was used in most forms of electronic equipment from mobile phones to laptops, calculators, and radios etc.
4. Materials, commodities and labour costs
5. Currency movements

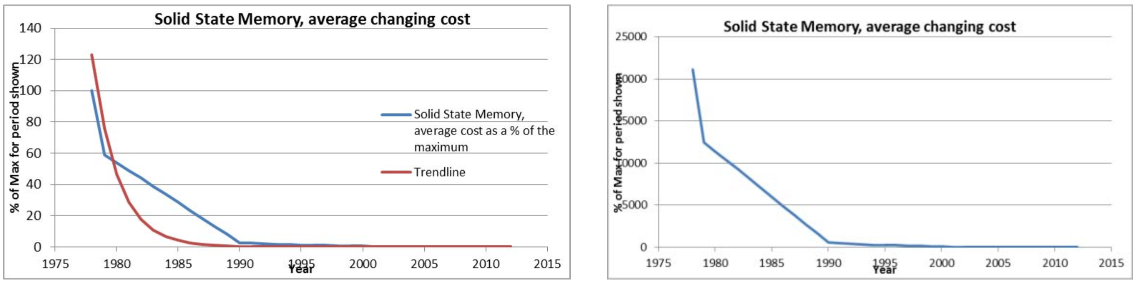

Figure 13.9 Cost curve – solid state memory costs per MB[83]

[83] Source of data; http://www.pcworld.com/article/246617/evolution_of_the_solidstate_drive.html accessed on 04.04.12.

14 Appendix E: Further information on the GB Model

This Annex provides further detail about the interdependencies between the generation and network models. The half-hourly demand profiles provide the main link between these models.

14.1 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[84]. This section provides an overview of the different demand profiles that we will consider.

Counterfactual – 2012-2023: 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[85]. 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.

Smart strategies– 2012-2023: 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 smart solution specifications, and so the generation model will produce identical costs for each (which will net off to zero).

Counterfactual –2023-2050 After enhanced smart meter communications are available, under the conventional investment strategy

[84] 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.

[85] 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.

After a pre-set date[86], 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.

Smart strategies (2023-2050) 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[87]. 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.

14.1.1 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
- 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.

14.2 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.

[86] As a default, the date has been set to 2023. This is purely a modelling assumption.
[87] 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.

14.3 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.

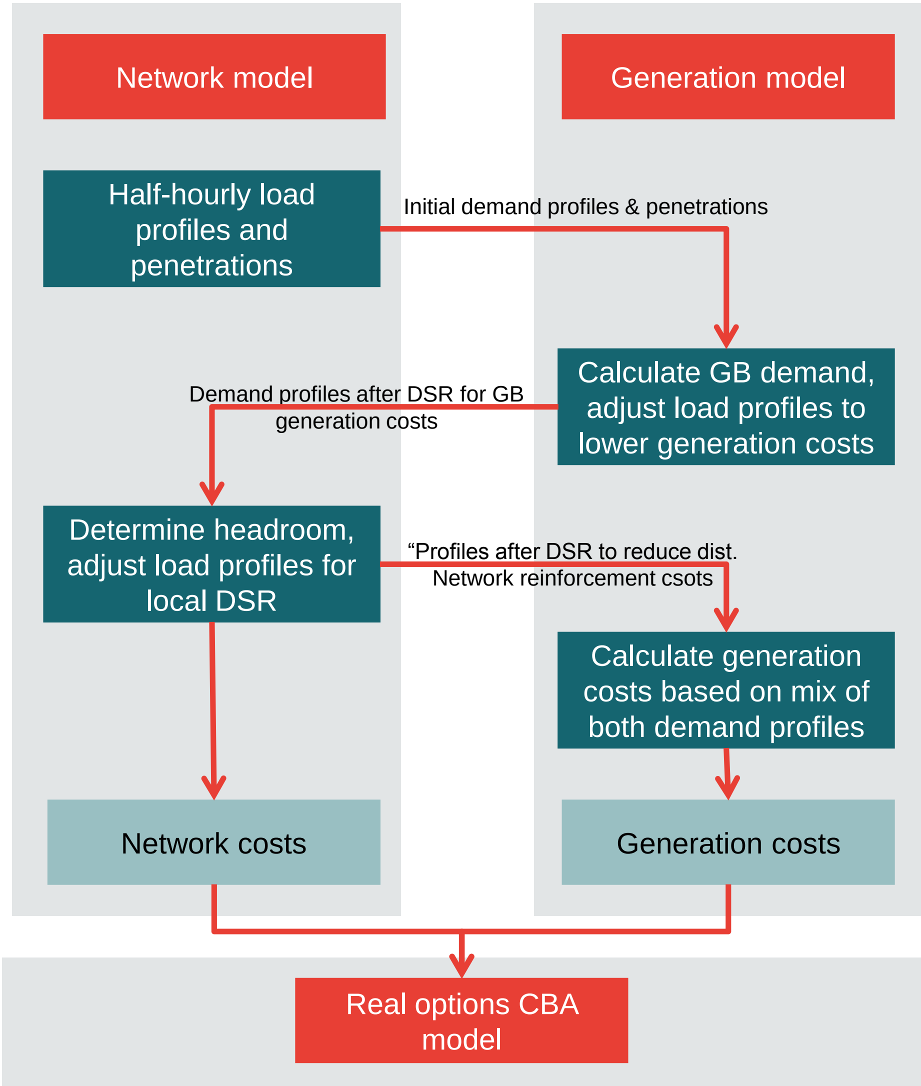

Figure 14.1 Overview of model interlinkages for DSR

14.3.1 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[88] (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 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).

[88] 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.

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.

14.3.2 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[89]. 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).

14.3.3 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.

14.4 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:

[89] 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.

- 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
- 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

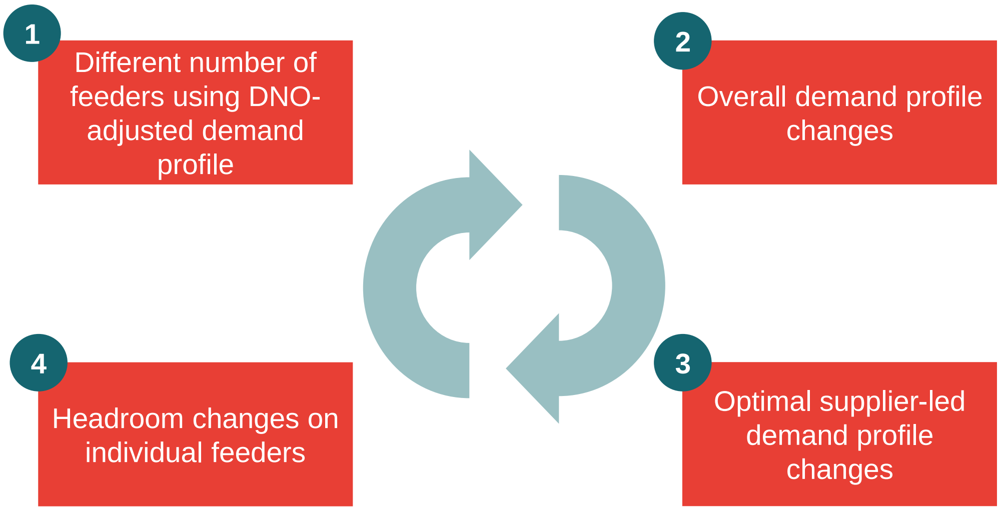

Figure 14.2 Feedback effects (Source: Frontier Economics)

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.

15 Appendix F: Full List of Scenario Data Provided by WS1 (DECC)

This appendix provides the following data on low carbon technology (LCT) uptake scenarios. These forecasts have been developed by government and are consistent with the LCT uptake scenarios used in the Work Stream 1 & 2 activities:

15.1 Photovoltaics scenarios

LOW	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
PV generation GWh (all sizes)	310	720	740	760	780	810	850	890	950	1,020
installations (all sizes)	215,000	219,000	226,000	234,000	244,000	256,000	271,000	289,000	310,000	336,000
MW (all sizes)	870	900	920	950	980	1,020	1,060	1,120	1,190	1,290

MID	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
PV generation GWh (all sizes)	310	760	850	950	1,050	1,170	1,300	1,450	1,630	1,850
installations (all sizes)	215,000	239,000	274,000	313,000	354,000	401,000	453,000	510,000	575,000	649,000
MW (all sizes)	870	960	1,070	1,200	1,330	1,470	1,640	1,820	2,050	2,340

HIGH	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
PV generation GWh (all sizes)	310	790	950	1,140	1,330	1,530	1,760	2,010	2,310	2,670
installations (all sizes)	215,000	258,000	323,000	391,000	464,000	545,000	634,000	731,000	840,000	963,000
MW (all sizes)	870	1,020	1,230	1,450	1,680	1,930	2,210	2,530	2,910	3,380

LOW	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
PV generation GWh (all sizes)	1,050	1,100	1,160	1,210	1,260	1,310	1,360	1,410	1,460	1,520
installations (all sizes)	341,000	355,000	369,000	382,000	392,000	402,000	414,000	424,000	434,000	444,000
MW (all sizes)	1,330	1,400	1,470	1,540	1,610	1,670	1,750	1,810	1,880	1,950

MID	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
PV generation GWh (all sizes)	2,050	2,280	2,530	2,810	3,110	3,460	3,840	4,260	4,730	5,250
installations (all sizes)	716,000	790,000	872,000	963,000	1,064,000	1,177,000	1,301,000	1,440,000	1,593,000	1,764,000
MW (all sizes)	2,600	2,880	3,200	3,550	3,940	4,370	4,850	5,390	5,980	6,640

HIGH	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
PV generation GWh (all sizes)	3,160	3,720	4,390	5,190	6,120	7,220	8,520	10,050	11,860	14,000
installations (all sizes)	1,091,000	1,237,000	1,405,000	1,598,000	1,818,000	2,070,000	2,368,000	2,720,000	3,134,000	3,623,000
MW (all sizes)	3,990	4,710	5,560	6,560	7,740	9,130	10,780	12,720	15,010	17,710

15.2 Plug-in Vehicles

15.2.1 Uptake scenarios

4th carbon budget plug-in cars uptake scenarios - cumulative total number of vehicles in each year

	70g ~20%PiV in 2030				60g ~40%PiV in 2030				50g ~50%PIV in 2030			
	#EV	#PHEV	#RE-EV	TWh	#EV	#PHEV	#RE-EV	TWh	#EV	#PHEV	#RE-EV	TWh
2011	1,000	0	0	0.0	1,000	0	0	0.0	1,000	0	0	0.0
2012	5,429	3,319	1,166	0.0	5,429	3,319	1,166	0.0	5,429	3,319	1,166	0.0
2013	16,350	7,352	2,583	0.0	16,350	7,352	2,583	0.0	16,350	7,352	2,583	0.0
2014	32,534	12,424	4,365	0.1	37,068	13,845	4,864	0.1	56,784	20,024	7,035	0.1
2015	57,101	21,378	7,511	0.2	70,479	26,023	9,143	0.3	129,561	46,549	16,355	0.3
2016	92,922	36,418	12,795	0.2	118,989	46,390	16,299	0.5	227,768	87,783	30,843	0.6
2017	138,751	58,467	20,542	0.4	181,671	76,548	26,895	0.8	348,505	145,872	51,253	0.9
2018	193,341	88,448	31,076	0.5	271,081	122,445	43,021	1.1	488,872	222,962	78,339	1.3
2019	255,445	127,283	44,721	0.7	385,388	187,003	65,703	1.5	645,970	321,198	112,854	1.8
2020	323,817	175,894	61,801	0.9	515,212	270,174	94,926	1.9	816,900	442,726	155,553	2.3
2021	403,343	239,423	84,122	1.2	668,965	381,537	134,054	2.4	1,035,031	605,533	212,755	2.9
2022	489,913	315,794	110,955	1.4	840,132	519,885	182,662	3.0	1,295,647	807,993	283,890	3.7
2023	578,784	408,855	143,652	1.8	1,021,681	689,843	242,377	3.8	1,593,397	1,054,404	370,467	4.7
2024	669,505	519,525	182,536	2.1	1,192,857	887,338	311,767	4.6	1,902,973	1,338,534	470,297	5.7
2025	757,276	646,204	227,045	2.5	1,360,322	1,119,081	393,190	5.5	2,219,257	1,656,862	582,142	6.9
2026	844,116	796,805	279,959	2.9	1,529,122	1,392,647	489,308	6.4	2,546,874	2,010,225	706,296	8.0
2027	928,626	972,363	341,641	3.4	1,696,678	1,709,944	600,790	7.4	2,886,436	2,398,169	842,600	9.3
2028	1,009,408	1,173,912	412,455	3.9	1,860,410	2,072,881	728,308	8.4	3,238,556	2,820,242	990,895	10.6
2029	1,085,063	1,402,488	492,765	4.4	2,017,738	2,483,366	872,533	9.5	3,603,845	3,275,991	1,151,023	12.0
2030	1,154,191	1,659,127	582,935	5.0	2,162,403	2,938,340	1,032,389	10.7	3,982,915	3,764,963	1,322,824	13.5

Car Scenarios 2030 – 2050; cumulative total

	70g ~20%PiV in 2030 (Trends)				60g ~40%PiV in 2030 – 2050 targets (Mix)				50g ~50%PIV in 2030 – 2050 targets (EV)			
	#EV	#PHEV	#RE-EV	TWh	#EV	#PHEV	#RE-EV	TWh	#EV	#PHEV	#RE-EV	TWh
2031	1,224,239	1,929,872	678,062	5.6	2,294,960	3,390,869	1,211,097	11.9	4,421,711	4,151,606	1,458,672	14.9
2032	1,298,388	2,216,810	778,878	6.3	2,421,261	3,837,349	1,413,267	13.1	4,943,699	4,434,227	1,557,971	16.1
2033	1,378,989	2,520,188	885,470	6.9	2,546,891	4,272,185	1,644,242	14.4	5,576,502	4,611,133	1,620,127	17.3
2034	1,468,394	2,840,256	997,927	7.7	2,677,643	4,688,585	1,910,705	15.7	6,352,711	4,680,631	1,644,545	18.6
2035	1,568,957	3,177,262	1,116,334	8.4	2,834,063	5,051,671	2,236,727	17.3	7,310,870	4,641,028	1,630,630	19.9
2036	1,676,458	3,522,581	1,237,662	9.2	3,024,622	5,344,973	2,637,910	18.9	8,496,632	4,490,631	1,577,788	21.5
2037	1,794,215	3,875,747	1,361,748	10.0	3,258,789	5,549,531	3,134,084	20.8	9,964,162	4,227,748	1,485,424	23.3
2038	1,925,545	4,236,296	1,488,428	10.9	3,546,633	5,642,017	3,749,818	23.0	11,777,804	3,850,685	1,352,943	25.6
2039	2,073,766	4,603,761	1,617,538	11.8	3,898,886	5,593,686	4,515,499	25.4	14,014,081	3,357,750	1,179,750	28.4
2040	2,242,197	4,977,677	1,748,913	12.7	4,327,027	5,369,089	5,468,649	28.2	16,764,081	2,747,250	965,250	31.8
2041	2,418,175	5,368,349	1,886,177	13.7	4,759,310	5,094,961	6,466,892	30.7	19,406,154	2,197,800	772,200	35.2
2042	2,600,875	5,773,943	2,028,683	14.7	5,196,041	4,760,721	7,520,169	33.0	21,919,121	1,709,400	600,600	38.4
2043	2,790,296	6,194,457	2,176,431	15.8	5,637,564	4,353,489	8,640,669	35.1	24,277,648	1,282,050	450,450	41.5
2044	2,986,438	6,629,892	2,329,421	16.9	6,084,259	3,857,580	9,843,340	36.8	26,451,428	915,750	321,750	44.4
2045	3,189,300	7,080,247	2,487,654	18.0	6,482,902	3,396,676	10,937,392	38.3	28,404,209	610,500	214,500	47.0
2046	3,398,884	7,545,523	2,651,130	19.2	6,827,741	2,990,019	11,897,972	39.6	30,092,623	366,300	128,700	49.3
2047	3,615,189	8,025,719	2,819,847	20.4	7,112,350	2,662,072	12,694,610	40.6	31,464,794	183,150	64,350	51.1
2048	3,838,215	8,520,836	2,993,807	21.6	7,329,563	2,443,763	13,289,933	41.3	32,458,664	61,050	21,450	52.5
2049	4,067,961	9,030,874	3,173,010	22.9	7,471,377	2,374,017	13,638,114	41.7	33,000,000	0	0	53.3
2050	4,304,429	9,555,833	3,357,455	24.2	7,528,862	2,501,634	13,682,953	41.7	33,000,000	0	0	53.3

4^{th} carbon budget plug-in vans uptake scenarios – cumulative total number of vehicles in each year

	105g ~20%PiV in 2030			90g ~35%PiV in 2030			75g ~50%PIV in 2030		
	#EV	#PHEV	TWh	#EV	#PHEV	TWh	#EV	#PHEV	TWh
2011	0	0	0.0	0	0	0.0	0	0	0.0
2012	723	0	0.0	723	0	0.0	723	0	0.0
2013	2,371	0	0.0	2,371	0	0.0	2,371	0	0.0
2014	5,052	141	0.0	8,325	313	0.0	10,220	413	0.0
2015	8,915	570	0.0	19,263	1,529	0.0	25,255	2,084	0.1
2016	15,157	1,941	0.0	33,205	4,589	0.1	44,744	6,362	0.1
2017	23,202	4,767	0.1	49,307	10,247	0.1	67,461	14,343	0.2
2018	32,488	9,551	0.1	66,751	19,233	0.2	92,212	27,094	0.3
2019	42,470	16,779	0.1	84,739	32,259	0.3	117,836	45,649	0.4
2020	52,617	26,926	0.2	102,495	50,014	0.3	143,201	71,014	0.5
2021	64,844	39,652	0.2	125,086	73,528	0.4	176,133	103,947	0.6
2022	78,295	55,007	0.3	151,485	102,910	0.5	215,770	144,306	0.8
2023	92,635	73,037	0.4	181,189	138,265	0.7	261,770	191,955	1.0
2024	107,630	93,645	0.4	210,528	179,382	0.8	308,724	246,344	1.2
2025	123,003	116,726	0.5	238,537	225,769	1.0	355,510	306,494	1.4
2026	139,856	144,750	0.6	269,343	279,659	1.1	408,662	374,858	1.7
2027	158,928	177,870	0.7	304,021	341,316	1.3	470,298	451,229	1.9
2028	180,944	216,312	0.8	343,623	411,108	1.6	542,565	535,496	2.3
2029	206,608	260,380	1.0	389,177	489,519	1.8	627,640	627,640	2.6
2030	236,611	310,457	1.1	441,682	577,155	2.1	727,741	727,741	3.1

Vans scenarios 2030 – 2050; cumulative total

	105g ~20%PiV in 2030 (Trends)			90g ~35%PiV in 2030 – 2050 targets (Mix)			75g ~50%PIV in 2030 – 2050 targets (EV)		
	#EV	#PHEV	TWh	#EV	#PHEV	TWh	#EV	#PHEV	TWh
2031	265,742	359,768	1.3	493,545	668,583	2.4	838,931	807,727	3.5
2032	297,234	412,913	1.5	545,324	764,561	2.7	964,124	867,741	3.9
2033	331,430	470,160	1.6	597,581	865,925	3.0	1,106,646	907,918	4.3
2034	368,670	531,783	1.8	650,889	973,604	3.3	1,270,293	928,395	4.7
2035	409,289	598,055	2.1	705,832	1,088,624	3.7	1,459,403	929,307	5.2
2036	451,201	666,172	2.3	760,580	1,209,033	4.0	1,675,007	906,852	5.7
2037	494,454	735,781	2.5	815,233	1,335,152	4.4	1,921,760	860,139	6.2
2038	539,097	806,471	2.7	869,915	1,467,336	4.7	2,205,084	788,214	6.7
2039	585,180	877,770	3.0	924,772	1,605,980	5.1	2,531,282	690,062	7.3
2040	632,757	949,135	3.2	979,977	1,751,520	5.5	2,907,680	564,596	8.0
2041	685,331	1,027,997	3.5	1,034,691	1,894,916	5.9	3,280,235	451,677	8.7
2042	740,017	1,110,026	3.8	1,088,664	2,035,303	6.3	3,646,172	351,304	9.4
2043	796,814	1,195,221	4.1	1,141,630	2,171,736	6.6	4,002,306	263,478	10.1
2044	855,721	1,283,582	4.4	1,193,309	2,303,185	7.0	4,344,975	188,199	10.8
2045	916,740	1,375,110	4.7	1,243,402	2,428,529	7.4	4,669,975	125,466	11.4
2046	979,869	1,469,804	5.0	1,291,593	2,546,542	7.7	4,972,476	75,280	12.1
2047	1,045,110	1,567,665	5.3	1,337,549	2,655,888	8.0	5,246,928	37,640	12.7
2048	1,112,461	1,668,692	5.7	1,380,914	2,755,112	8.3	5,486,960	12,547	13.2
2049	1,181,924	1,772,886	6.0	1,421,312	2,842,624	8.5	5,685,249	0	13.6
2050	1,253,497	1,880,246	6.4	1,458,346	2,916,693	8.8	5,833,385	0	14.0

15.2.2 Recharging locations

Car recharging location

	70g ~20%PiV in 2030			60g ~40%PiV in 2030			50g ~50%PIV in 2030		
	@ HOME	@ WORK	On-Street	@ HOME	@ WORK	On-Street	@ HOME	@ WORK	On-Street
2011	32.3%	54.7%	13.0%	32.3%	54.7%	13.0%	32.3%	54.7%	13.0%
2012	39.4%	53.6%	7.0%	39.4%	53.6%	7.0%	39.4%	53.6%	7.0%
2013	46.5%	45.5%	8.0%	46.5%	45.5%	8.0%	46.5%	45.5%	8.0%
2014	53.4%	38.1%	8.5%	53.3%	38.0%	8.7%	53.3%	38.0%	8.7%
2015	60.8%	30.7%	8.5%	60.6%	30.8%	8.6%	60.5%	30.8%	8.7%
2016	63.2%	28.3%	8.5%	62.4%	29.1%	8.5%	62.3%	29.2%	8.5%
2017	65.8%	25.9%	8.4%	64.3%	27.4%	8.3%	64.1%	27.6%	8.3%
2018	68.1%	23.7%	8.1%	67.1%	24.7%	8.1%	66.9%	25.0%	8.1%
2019	70.6%	21.4%	7.9%	70.3%	21.8%	7.9%	70.1%	22.0%	7.9%
2020	73.2%	19.0%	7.7%	73.2%	19.1%	7.8%	73.0%	19.2%	7.7%
2021	75.3%	17.2%	7.5%	75.4%	17.1%	7.5%	75.2%	17.2%	7.6%
2022	76.8%	15.9%	7.3%	76.9%	15.9%	7.3%	76.7%	15.9%	7.4%
2023	78.0%	15.0%	7.0%	77.9%	15.1%	7.0%	77.7%	15.0%	7.2%
2024	78.8%	14.4%	6.7%	78.6%	14.7%	6.7%	78.3%	14.6%	7.1%
2025	79.7%	13.8%	6.5%	79.4%	14.2%	6.4%	79.0%	14.1%	6.9%
2026	80.5%	13.3%	6.1%	80.2%	13.7%	6.1%	79.8%	13.5%	6.7%
2027	81.3%	12.9%	5.8%	81.1%	13.1%	5.8%	80.5%	12.9%	6.6%
2028	81.9%	12.6%	5.5%	81.9%	12.6%	5.5%	81.3%	12.3%	6.5%
2029	82.6%	12.3%	5.2%	82.8%	12.0%	5.2%	82.0%	11.7%	6.3%
2030	83.3%	11.9%	4.8%	83.6%	11.5%	4.9%	82.7%	11.1%	6.2%
2031	83.7%	11.8%	4.6%	84.0%	11.3%	4.7%	82.9%	10.8%	6.3%
2032	84.0%	11.7%	4.4%	84.3%	11.2%	4.5%	83.1%	10.4%	6.5%
2033	84.3%	11.6%	4.2%	84.5%	11.2%	4.3%	83.2%	10.0%	6.8%
2034	84.5%	11.5%	4.0%	84.6%	11.2%	4.2%	83.1%	9.7%	7.3%
2035	84.7%	11.4%	3.9%	84.7%	11.3%	4.1%	82.8%	9.4%	7.8%
2036	84.9%	11.3%	3.9%	84.7%	11.3%	4.0%	82.3%	9.3%	8.4%
2037	85.0%	11.2%	3.8%	84.7%	11.4%	4.0%	81.6%	9.3%	9.1%
2038	85.1%	11.2%	3.7%	84.6%	11.4%	4.0%	80.9%	9.3%	9.8%
2039	85.2%	11.1%	3.7%	84.6%	11.5%	4.0%	80.1%	9.4%	10.5%
2040	85.2%	11.0%	3.7%	84.5%	11.5%	4.0%	79.2%	9.5%	11.2%
2041	85.3%	11.0%	3.7%	84.6%	11.4%	4.0%	74.3%	9.5%	16.2%
2042	85.4%	10.9%	3.7%	84.8%	11.2%	4.0%	71.2%	9.2%	19.6%
2043	85.4%	10.8%	3.7%	85.1%	10.8%	4.1%	68.5%	8.8%	22.6%
2044	85.5%	10.8%	3.7%	85.6%	10.3%	4.1%	66.3%	8.3%	25.5%
2045	85.5%	10.7%	3.7%	86.0%	9.9%	4.1%	64.1%	7.8%	28.0%
2046	85.6%	10.7%	3.7%	86.3%	9.6%	4.1%	62.1%	7.5%	30.4%
2047	85.6%	10.6%	3.7%	86.5%	9.4%	4.1%	60.2%	7.2%	32.6%
2048	85.7%	10.6%	3.7%	86.7%	9.2%	4.1%	58.3%	7.0%	34.7%
2049	85.7%	10.6%	3.8%	86.7%	9.1%	4.1%	56.5%	6.9%	36.6%
2050	85.7%	10.5%	3.8%	86.7%	9.1%	4.1%	54.8%	6.9%	38.3%

Van recharging location

	70g ~20%PiV in 2030			60g ~40%PiV in 2030			50g ~50%PIV in 2030		
	@ HOME	@ WORK	On-Street	@ HOME	@ WORK	On-Street	@ HOME	@ WORK	On-Street
2011									
2012	0.0%	86.3%	13.8%	0.0%	86.3%	13.8%	0.0%	86.3%	13.8%
2013	0.0%	86.3%	13.8%	0.0%	86.3%	13.8%	0.0%	86.3%	13.8%
2014	0.0%	86.5%	13.5%	0.0%	86.6%	13.4%	0.0%	86.7%	13.3%
2015	0.0%	86.9%	13.1%	0.0%	87.0%	13.0%	0.0%	87.1%	12.9%
2016	1.3%	83.7%	15.0%	0.6%	85.8%	13.6%	0.4%	86.3%	13.2%
2017	2.7%	80.4%	16.9%	1.2%	84.5%	14.2%	0.9%	85.5%	13.6%
2018	4.0%	77.5%	18.5%	3.3%	79.6%	17.1%	3.0%	80.6%	16.4%
2019	5.5%	74.7%	19.8%	6.2%	73.0%	20.8%	5.9%	74.0%	20.1%
2020	7.9%	70.1%	21.9%	9.2%	67.0%	23.8%	8.9%	67.9%	23.2%
2021	10.6%	65.6%	23.8%	11.8%	62.6%	25.6%	11.6%	63.3%	25.1%
2022	13.1%	62.1%	24.8%	14.0%	59.7%	26.3%	13.8%	60.2%	26.0%
2023	15.4%	59.4%	25.2%	15.9%	57.8%	26.3%	15.7%	58.1%	26.1%
2024	17.6%	57.3%	25.1%	17.4%	57.3%	25.4%	17.2%	57.4%	25.4%
2025	19.8%	55.1%	25.1%	19.0%	56.3%	24.6%	18.8%	56.4%	24.8%
2026	21.3%	54.1%	24.6%	20.5%	55.5%	24.0%	20.2%	55.4%	24.4%
2027	22.3%	53.8%	23.9%	21.8%	54.7%	23.5%	21.3%	54.6%	24.1%
2028	22.7%	54.2%	23.2%	22.7%	54.2%	23.1%	22.0%	53.9%	24.0%
2029	22.6%	55.0%	22.4%	23.3%	53.9%	22.8%	22.4%	53.5%	24.0%
2030	22.8%	55.1%	22.1%	23.9%	53.2%	22.8%	22.8%	52.9%	24.3%
2031	23.6%	54.3%	22.1%	24.7%	52.4%	22.9%	24.2%	51.7%	24.1%
2032	24.6%	53.1%	22.4%	25.6%	51.4%	23.0%	25.8%	50.1%	24.1%
2033	25.8%	51.5%	22.7%	26.6%	50.3%	23.1%	27.6%	48.2%	24.3%
2034	27.1%	49.8%	23.1%	27.7%	48.9%	23.4%	29.5%	46.0%	24.5%
2035	27.9%	48.8%	23.3%	28.7%	47.8%	23.5%	30.8%	44.5%	24.7%
2036	28.5%	48.1%	23.4%	29.4%	47.1%	23.5%	31.6%	43.7%	24.7%
2037	29.0%	47.5%	23.5%	30.0%	46.6%	23.5%	31.9%	43.4%	24.7%
2038	29.3%	47.1%	23.6%	30.4%	46.3%	23.3%	31.9%	43.6%	24.5%
2039	29.5%	46.8%	23.6%	30.7%	46.2%	23.1%	31.7%	44.1%	24.2%
2040	29.6%	46.7%	23.7%	30.9%	46.3%	22.8%	31.4%	44.8%	23.8%
2041	29.8%	46.3%	23.8%	31.2%	46.1%	22.7%	30.6%	44.9%	24.5%
2042	30.1%	46.0%	24.0%	31.8%	45.5%	22.7%	30.3%	44.5%	25.3%
2043	30.3%	45.7%	24.1%	32.5%	44.7%	22.8%	30.5%	43.4%	26.1%
2044	30.4%	45.4%	24.2%	33.5%	43.6%	22.9%	31.1%	41.8%	27.1%
2045	30.6%	45.1%	24.3%	34.2%	42.7%	23.1%	31.7%	40.5%	27.8%
2046	30.8%	44.8%	24.4%	34.8%	42.0%	23.2%	32.2%	39.3%	28.4%
2047	30.9%	44.6%	24.5%	35.3%	41.4%	23.3%	32.6%	38.5%	28.9%
2048	31.1%	44.4%	24.5%	35.6%	41.0%	23.4%	33.0%	37.9%	29.2%
2049	31.2%	44.2%	24.6%	35.8%	40.8%	23.4%	33.2%	37.5%	29.3%
2050	31.3%	44.0%	24.7%	35.9%	40.7%	23.4%	33.2%	37.5%	29.3%

15.2.3 Recharging speed

Car recharging speed

	70g ~20%PiV in 2030			60g ~40%PiV in 2030			50g ~50%PIV in 2030		
	Slow	**Fast**	**Rapid**	**Slow**	**Fast**	**Rapid**	**Slow**	**Fast**	**Rapid**
2011	87.0%	0.0%	13.0%	87.0%	0.0%	13.0%	87.0%	0.0%	13.0%
2012	85.0%	8.0%	7.0%	85.0%	8.0%	7.0%	85.0%	8.0%	7.0%
2013	77.0%	15.0%	8.0%	77.0%	15.0%	8.0%	77.0%	15.0%	8.0%
2014	70.4%	21.1%	8.5%	70.2%	21.1%	8.7%	70.2%	21.1%	8.7%
2015	65.0%	26.4%	8.5%	64.9%	26.4%	8.6%	64.9%	26.5%	8.6%
2016	59.1%	32.3%	8.5%	58.9%	32.6%	8.5%	58.9%	32.6%	8.5%
2017	53.6%	38.0%	8.4%	53.1%	38.6%	8.3%	53.1%	38.6%	8.3%
2018	48.3%	43.6%	8.1%	47.9%	44.0%	8.1%	47.8%	44.1%	8.1%
2019	43.3%	48.8%	7.9%	43.1%	48.9%	7.9%	43.0%	49.0%	7.9%
2020	38.5%	53.7%	7.7%	38.5%	53.7%	7.8%	38.4%	53.8%	7.7%
2021	35.7%	56.8%	7.5%	35.7%	56.8%	7.5%	35.6%	56.8%	7.6%
2022	32.4%	60.4%	7.3%	32.4%	60.4%	7.3%	32.3%	60.3%	7.4%
2023	28.7%	64.3%	7.0%	28.7%	64.3%	7.0%	28.6%	64.1%	7.2%
2024	24.9%	68.4%	6.7%	24.8%	68.5%	6.7%	24.7%	68.2%	7.1%
2025	21.0%	72.6%	6.5%	20.9%	72.7%	6.4%	20.8%	72.3%	6.9%
2026	17.0%	76.9%	6.1%	16.9%	77.0%	6.1%	16.8%	76.5%	6.7%
2027	12.8%	81.4%	5.8%	12.8%	81.4%	5.8%	12.7%	80.7%	6.6%
2028	8.6%	85.9%	5.5%	8.6%	85.9%	5.5%	8.6%	85.0%	6.5%
2029	4.3%	90.5%	5.2%	4.4%	90.5%	5.2%	4.3%	89.3%	6.3%
2030	0.0%	95.2%	4.8%	0.0%	95.1%	4.9%	0.0%	93.8%	6.2%
2031	0.0%	95.4%	4.6%	0.0%	95.3%	4.7%	0.0%	93.7%	6.3%
2032	0.0%	95.6%	4.4%	0.0%	95.5%	4.5%	0.0%	93.5%	6.5%
2033	0.0%	95.8%	4.2%	0.0%	95.7%	4.3%	0.0%	93.2%	6.8%
2034	0.0%	96.0%	4.0%	0.0%	95.8%	4.2%	0.0%	92.7%	7.3%
2035	0.0%	96.1%	3.9%	0.0%	95.9%	4.1%	0.0%	92.2%	7.8%
2036	0.0%	96.1%	3.9%	0.0%	96.0%	4.0%	0.0%	91.6%	8.4%
2037	0.0%	96.2%	3.8%	0.0%	96.0%	4.0%	0.0%	90.9%	9.1%
2038	0.0%	96.3%	3.7%	0.0%	96.0%	4.0%	0.0%	90.2%	9.8%
2039	0.0%	96.3%	3.7%	0.0%	96.0%	4.0%	0.0%	89.5%	10.5%
2040	0.0%	96.3%	3.7%	0.0%	96.0%	4.0%	0.0%	88.8%	11.2%
2041	0.0%	96.3%	3.7%	0.0%	96.0%	4.0%	0.0%	90.7%	9.3%
2042	0.0%	96.3%	3.7%	0.0%	96.0%	4.0%	0.0%	91.1%	8.9%
2043	0.0%	96.3%	3.7%	0.0%	95.9%	4.1%	0.0%	91.3%	8.7%
2044	0.0%	96.3%	3.7%	0.0%	95.9%	4.1%	0.0%	91.6%	8.4%
2045	0.0%	96.3%	3.7%	0.0%	95.9%	4.1%	0.0%	91.9%	8.1%
2046	0.0%	96.3%	3.7%	0.0%	95.9%	4.1%	0.0%	92.2%	7.8%
2047	0.0%	96.3%	3.7%	0.0%	95.9%	4.1%	0.0%	92.6%	7.4%
2048	0.0%	96.3%	3.7%	0.0%	95.9%	4.1%	0.0%	93.0%	7.0%
2049	0.0%	96.2%	3.8%	0.0%	95.9%	4.1%	0.0%	89.4%	10.6%
2050	0.0%	96.2%	3.8%	0.0%	95.9%	4.1%	0.0%	89.7%	10.3%

Van recharging speed

	70g ~20%PiV in 2030			60g ~40%PiV in 2030			50g ~50%PIV in 2030		
	Slow	**Fast**	**Rapid**	**Slow**	**Fast**	**Rapid**	**Slow**	**Fast**	**Rapid**
2011	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
2012	76.7%	9.6%	13.8%	76.7%	9.6%	13.8%	76.7%	9.6%	13.8%
2013	67.1%	19.2%	13.8%	67.1%	19.2%	13.8%	67.1%	19.2%	13.8%
2014	57.7%	28.8%	13.5%	57.8%	28.9%	13.4%	57.8%	28.9%	13.4%
2015	48.3%	38.6%	13.1%	48.3%	38.7%	13.0%	48.4%	38.7%	13.0%
2016	38.2%	46.8%	15.0%	38.6%	47.8%	13.6%	38.7%	47.7%	13.6%
2017	28.6%	54.5%	16.9%	29.0%	56.7%	14.2%	29.1%	56.6%	14.2%
2018	19.8%	61.8%	18.5%	19.8%	63.1%	17.1%	19.8%	63.1%	17.1%
2019	11.5%	68.7%	19.8%	11.7%	67.5%	20.8%	11.6%	68.2%	20.1%
2020	4.2%	73.9%	21.9%	4.8%	71.4%	23.8%	4.7%	72.1%	23.2%
2021	5.0%	71.2%	23.8%	5.6%	68.8%	25.6%	5.5%	69.4%	25.1%
2022	5.5%	69.7%	24.8%	5.9%	67.8%	26.3%	5.8%	68.2%	26.0%
2023	5.7%	69.1%	25.2%	5.9%	67.9%	26.3%	5.8%	68.1%	26.1%
2024	5.6%	69.4%	25.1%	5.5%	69.2%	25.4%	5.4%	69.2%	25.4%
2025	5.2%	69.7%	25.1%	5.0%	70.4%	24.6%	5.0%	70.2%	24.8%
2026	4.5%	70.9%	24.6%	4.3%	71.7%	24.0%	4.3%	71.3%	24.4%
2027	3.5%	72.6%	23.9%	3.4%	73.0%	23.5%	3.4%	72.5%	24.1%
2028	2.4%	74.5%	23.2%	2.4%	74.5%	23.1%	2.3%	73.7%	24.0%
2029	1.2%	76.4%	22.4%	1.2%	75.9%	22.8%	1.2%	74.8%	24.0%
2030	0.0%	77.9%	22.1%	0.0%	77.2%	22.8%	0.0%	75.7%	24.3%
2031	0.0%	77.9%	22.1%	0.0%	77.1%	22.9%	0.0%	75.9%	24.1%
2032	0.0%	77.6%	22.4%	0.0%	77.0%	23.0%	0.0%	75.9%	24.1%
2033	0.0%	77.3%	22.7%	0.0%	76.9%	23.1%	0.0%	75.7%	24.3%
2034	0.0%	76.9%	23.1%	0.0%	76.6%	23.4%	0.0%	75.5%	24.5%
2035	0.0%	76.7%	23.3%	0.0%	76.5%	23.5%	0.0%	75.3%	24.7%
2036	0.0%	76.6%	23.4%	0.0%	76.5%	23.5%	0.0%	75.3%	24.7%
2037	0.0%	76.5%	23.5%	0.0%	76.5%	23.5%	0.0%	75.3%	24.7%
2038	0.0%	76.4%	23.6%	0.0%	76.7%	23.3%	0.0%	75.5%	24.5%
2039	0.0%	76.4%	23.6%	0.0%	76.9%	23.1%	0.0%	75.8%	24.2%
2040	0.0%	76.3%	23.7%	0.0%	77.2%	22.8%	0.0%	76.2%	23.8%
2041	0.0%	76.2%	23.8%	0.0%	77.3%	22.7%	0.0%	75.5%	24.5%
2042	0.0%	76.0%	24.0%	0.0%	77.3%	22.7%	0.0%	74.7%	25.3%
2043	0.0%	75.9%	24.1%	0.0%	77.2%	22.8%	0.0%	73.9%	26.1%
2044	0.0%	75.8%	24.2%	0.0%	77.1%	22.9%	0.0%	72.9%	27.1%
2045	0.0%	75.7%	24.3%	0.0%	76.9%	23.1%	0.0%	72.2%	27.8%
2046	0.0%	75.6%	24.4%	0.0%	76.8%	23.2%	0.0%	71.6%	28.4%
2047	0.0%	75.5%	24.5%	0.0%	76.7%	23.3%	0.0%	71.1%	28.9%
2048	0.0%	75.5%	24.5%	0.0%	76.6%	23.4%	0.0%	70.8%	29.2%
2049	0.0%	75.4%	24.6%	0.0%	76.6%	23.4%	0.0%	70.7%	29.3%
2050	0.0%	75.3%	24.7%	0.0%	76.6%	23.4%	0.0%	70.7%	29.3%

15.3 Heat pump scenarios

Low scenario

Cumulative heat pumps installed (thousands)									
Year	Residential		Business		Public		Total Residential	Total Business	Total Public
	No storage	Storage	No storage	Storage	No storage	Storage			
2012	0.0	0.0	5.3	5.5	5.4	8.5	0.0	10.8	13.9
2013	0.0	0.0	6.7	6.9	6.7	10.7	0.0	13.6	17.4
2014	0.0	0.0	8.1	8.3	8.1	12.8	0.0	16.4	20.9
2015	0.0	0.0	9.4	9.7	9.4	15.0	0.0	19.1	24.4
2016	0.0	6.5	10.8	11.0	10.8	17.1	6.5	21.8	27.9
2017	0.0	32.4	12.1	12.4	12.2	19.3	32.4	24.5	31.5
2018	0.0	129.7	13.5	13.8	13.5	21.4	129.7	27.3	34.9
2019	0.0	324.3	14.8	15.2	14.9	23.6	324.3	30.0	38.5
2020	0.0	648.5	16.2	16.6	16.3	25.7	648.5	32.8	42.0
2021	0.0	695.3	17.9	18.4	18.0	28.4	695.3	36.3	46.4
2022	0.0	742.0	19.7	20.2	19.8	31.3	742.0	39.9	51.1
2023	0.0	789.2	21.5	22.1	21.6	34.3	789.2	43.6	55.9
2024	0.0	837.0	23.4	24.0	23.5	36.5	837.0	47.4	60.0
2025	0.0	886.4	25.4	26.0	25.4	36.5	886.4	51.4	61.9
2026	0.0	938.4	27.4	28.1	27.4	40.0	938.4	55.5	67.4
2027	0.0	988.8	29.5	30.2	29.4	43.6	988.8	59.7	73.0
2028	0.0	1,037.7	31.6	32.4	31.4	47.4	1,037.7	64.0	78.8
2029	0.0	1,093.9	33.6	34.7	33.4	51.3	1,093.9	68.3	84.7
2030	0.0	1,147.2	36.2	37.0	35.9	55.4	1,147.2	73.2	91.3

Mid scenario

Cumulative heat pumps installed (thousands)									
Year	**Residential**		**Business**		**Public**		**Total Residential**	**Total Business**	**Total Public**
	No storage	**Storage**	**No storage**	**Storage**	**No storage**	**Storage**			
2012	0.0	0.0	12.1	0.0	12.6	0.0	0.0	12.1	12.6
2013	0.0	0.0	15.2	0.0	15.7	0.0	0.0	15.2	15.7
2014	0.0	0.0	18.3	0.0	18.9	0.0	0.0	18.3	18.9
2015	0.0	0.0	21.4	0.0	22.1	0.0	0.0	21.4	22.1
2016	0.1	6.4	24.4	0.0	25.3	0.0	6.5	24.4	25.3
2017	0.4	32.0	27.5	0.0	28.5	0.0	32.4	27.5	28.5
2018	1.7	128.0	30.6	0.0	31.7	0.0	129.7	30.6	31.7
2019	4.2	320.0	33.7	0.0	34.9	0.0	324.2	33.7	34.9
2020	8.4	640.1	36.7	0.0	38.1	0.0	648.5	36.7	38.1
2021	12.6	957.6	43.0	0.0	44.5	0.0	970.2	43.0	44.5
2022	16.9	1,401.7	49.4	0.0	51.1	0.0	1,418.6	49.4	51.1
2023	26.6	1,913.2	56.1	0.0	58.0	0.0	1,939.8	56.1	58.0
2024	56.2	2,478.6	63.1	0.0	65.0	0.0	2,534.8	63.1	65.0
2025	86.0	3,043.2	70.3	0.0	72.3	0.0	3,129.2	70.3	72.3
2026	115.9	3,619.3	75.8	2.1	79.7	0.0	3,735.2	77.9	79.7
2027	146.0	4,206.6	81.4	4.2	87.4	0.0	4,352.6	85.6	87.4
2028	176.4	4,804.8	87.2	6.4	95.1	0.0	4,981.2	93.6	95.1
2029	209.7	5,409.7	93.1	8.7	103.1	0.0	5,619.4	101.8	103.1
2030	257.8	6,008.2	99.3	10.9	111.3	0.0	6,266.0	110.2	111.3

High scenario

Cumulative heat pumps installed (thousands)									
Year	Residential		Business		Public		Total Residential	Total Business	Total Public
	No storage	Storage	No storage	Storage	No storage	Storage			
2012	0.0	0.0	11.9	0.3	12.1	0.4	0.0	12.2	12.5
2013	0.0	0.0	14.9	0.4	15.1	0.5	0.0	15.3	15.6
2014	0.0	0.0	17.9	0.5	18.2	0.6	0.0	18.4	18.8
2015	0.0	0.0	20.9	0.6	21.2	0.8	0.0	21.5	22.0
2016	0.1	6.4	23.9	0.7	24.3	0.9	6.5	24.6	25.2
2017	0.6	31.8	27.0	0.7	27.3	1.0	32.4	27.7	28.3
2018	2.3	127.4	30.0	0.8	30.4	1.1	129.7	30.8	31.5
2019	5.7	318.5	33.0	0.9	33.5	1.2	324.2	33.9	34.7
2020	11.4	637.1	36.0	1.0	36.5	1.3	648.5	37.0	37.8
2021	16.7	934.5	43.4	1.2	44.1	1.6	951.2	44.6	45.7
2022	22.1	1,320.6	51.2	1.2	52.0	1.5	1,342.7	52.4	53.5
2023	27.7	1,828.9	59.1	1.2	59.9	1.6	1,856.6	60.3	61.5
2024	33.5	2,549.3	67.2	1.2	68.0	1.6	2,582.8	68.4	69.6
2025	54.5	3,306.8	75.5	1.2	76.3	1.6	3,361.3	76.7	77.9
2026	105.4	4,098.5	81.8	3.3	84.6	1.6	4,203.9	85.1	86.2
2027	156.5	4,901.3	88.3	5.4	93.2	1.6	5,057.8	93.7	94.8
2028	207.9	5,715.9	95.0	7.6	101.8	1.6	5,923.8	102.6	103.4
2029	259.3	6,536.3	101.7	9.9	110.6	1.6	6,795.6	111.6	112.2
2030	325.9	7,319.6	108.6	12.3	118.8	1.6	7,645.5	120.9	120.4

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