UK Power Networks

Business plan (2015 to 2023)

Annex 9: Smart Grid Strategy

March 2014

“A reliable... an innovative... and the lowest price electricity distribution group.”

UK Power Networks
Delivering your electricity

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Document History

Version	Date	Revision Class	Originator	Section Update	Details
1.0	03/02/2014	N/A	Adrian Searle	N/A	Initial version (ED1 July 2013 submission baseline)
1.1	26/02/2014	Minor	Nick Heyward	Multiple Sections	Amendments to declared Smart Savings as a result of NAMP changes in Re-Submission. Errata corrected.
1.2	28/02/2014	Minor	Martin Wilcox	Multiple Sections	Amendments to NPVs as a result of WACC change to 4.1% used in Cost-benefit analysis. Minor revisions to copy.
1.3	04/03/2014	Minor	Adrian Searle	Multiple Sections	Minor re-formatting changes.
1.4	07/03/2014	Minor	Nick Heyward	Table 3	Amendments to scenario assumptions in line with Core Scenario business plan docs

Contents

1 Executive summary

This document sets out both UK Power Networks' Smart Grid strategy and the financial impact that it has made on our business plan for the RIIO-ED1 price control. Our customers will directly benefit from the £111 million of savings in network reinforcement we have included in our RIIO-ED1 business plan submission based on our innovation portfolio and around £30 million of on-going and continued savings from practices we are following which already represent a Smart Grid approach.

Our two models, the LRE model and Transform model, played an important part in identifying the savings. The models gave us two good views of the volume of savings that could be achieved and what technologies could be considered. Both sets of information were used by our network planners and innovation team to make the final decision on what smart solutions could be deployed to give us our savings.

The document presents a summary risk register for these savings, and provides, wherever possible, alternative sources of data assurance to support our implementation plans. The plan represents a level of risk for UK Power Networks shareholders, but is well substantiated and clearly in the interests of customers. The level of savings compares favourably with the level of savings predicted by the Transform model developed under the auspices of the Smart Grid Forum, although we differ in the detail of which Smart Grid solutions UK Power Networks is currently backing.

Each of our Smart Grid solutions was tested using one of Ofgem's approved methodologies for assessing cost-benefit. In a number of instances we favoured the Smart Grid solution based on the optionality and flexibility that it introduces in the early years. We feel that this is particularly valuable during a period in which the uptake of Low Carbon Technologies (LCT) will increase, but at a rate that cannot be fully predicted.

In the most significant area in which there has been discussion about investing during RIIO-ED1 in order to prepare for RIIO-ED2, Information and Communication Technologies (ICT), we have at this stage opted to monitor the situation further. Our analysis suggests that the quantitative case for building out ICT infrastructure during RIIO-ED1 is still highly sensitive to the policy environment and uptake in LCTs. As such, we have used a qualitative approach to identify a suite of ICT requirements which will be required under any scenario, and are actively working in innovation projects such as Low Carbon London and Flexible Plug and Play (FPP) on the ICT solutions that will be required in higher growth scenarios.

Finally, we are developing our IT architecture thinking ahead of time, showing a roadmap by which today's experimental systems or trials can become reliable solutions for use on a day-to-day basis but on a relatively limited scale. This transition is self-funding from within the savings listed in this document achieved by moving to the Smart Grid solution. The roadmap then shows how this would eventually need to be replaced by an enduring or 'enterprise' solution, but we are looking in the first instance to substantiate the funding required for this transition once the uptake is clearer.

2 Introduction

UK Power Networks has one of the strongest innovation track records amongst the GB Distribution Network Operators (DNOs) and has had a formal, internal, Smart Grid strategy in place since the end of 2009 known as the 'Future Network Development Plan'. Both technical innovation and improvements in business processes have informed our business plan throughout.

This Smart Grid strategy, together with our wider Innovation Strategy, have enables us to commit ourselves to £111 million of network reinforcement savings in our RIIO-ED1 business plan submission based on our innovation portfolio and around £30 million of on-going and continued savings from practices we are following which are already 'Smart'. The detail on this saving will be presented later in this document.

This annex brings together in a single place the subset of those innovations and improvements within our business plan which are widely recognised as 'Smart Grid' responses to the challenges that the DNOs face. The purpose of the annex is to:

- Present our Smart Grid strategy and the technology roadmap which it contains, and which UK Power Networks' innovation and deployment activities are guided by
- Provide detail on the Smart Grid solutions which either form part of our committed network investment plans, or which we plan to roll-out to new connections customers
- Demonstrate the saving that we are achieving by deploying these solutions
- Provide the background to our decisions including the modelling tools which we have used and the cost-benefit analysis for each solution
- Provide clear comparisons between the plans that we are submitting and the raw output from our modelling tools, explaining differences where necessary
- Where required, explain why we have not committed to particular Smart Grid solutions at this stage

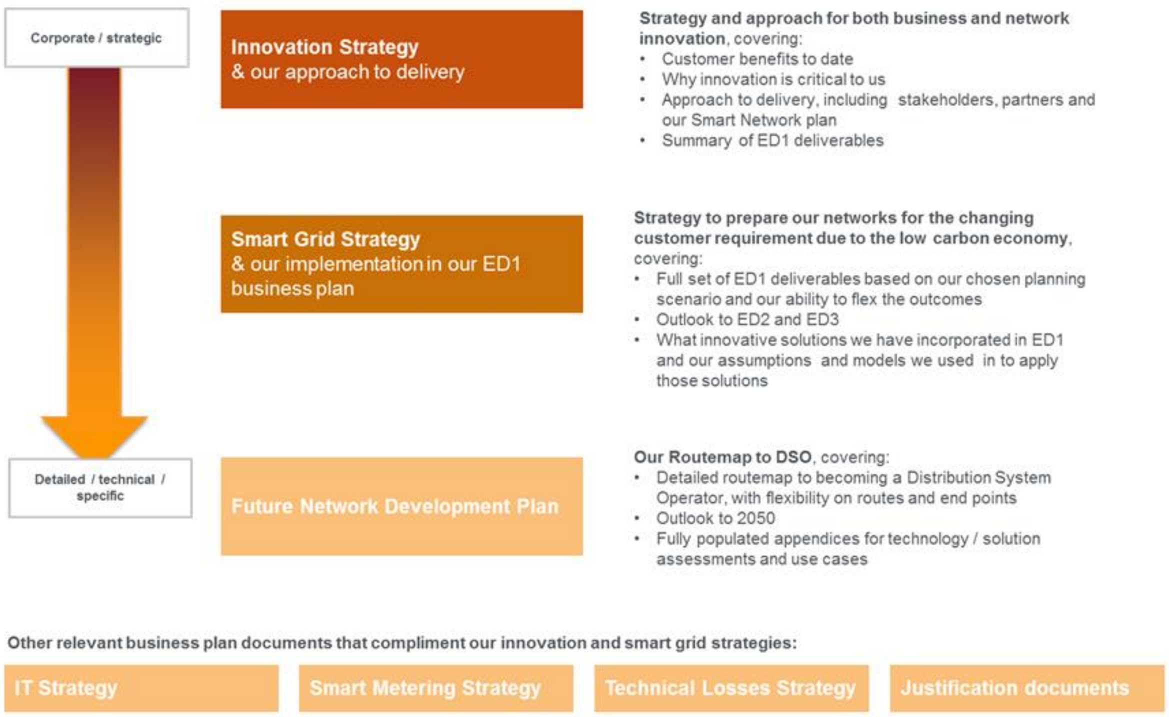
The document is presented in two parts. The first part presents our Smart Grid strategy, and which expands on the information we provide in our Innovation Strategy. The second part covers the detail on the smart grid solutions included in our business plan and the way in which we have modelled scenarios.

Readers who are looking to readily see a breakdown of our savings delivered by Smart Grids will find this in Chapter 5. Readers who are looking to cross-reference our Smart Grid strategy to our Business Plan Data template will find this in Chapter 6, and readers looking to cross-reference our submission to the outputs from the Transform model and the solutions in the Transform model will find this in Chapter 7.

2.1 Suite of documents on innovation and smart grids

This document is part of a suite of documents with ranging levels of outlook and detail, depending on where they are applicable across our business. The figure below puts this document in context of this wider suite on innovation and Smart Grids.

Figure 1 Our suite on innovation and smart grids



The suite comprises:

- The Innovation Strategy, which provides the list of expected deliverables from our RIIO ED1 innovation portfolio. Smart Grid solutions represent a subset of the wider technical and commercial innovation and continual improvement initiatives covered within our Innovation Strategy. In particular, the Innovation Strategy explains the Smart Network Plan process by which we are readying UK Power Networks to deliver the savings from Smart Grids which are committed to in this document.
- The Smart Grid Strategy, which provides a single statement of the impact which Smart Grid solutions have had on our ED1 business plan and may have on our future RIIO-ED2 plans.
- The Future Network Development Plan, which is our full Routemap to DSO. We publish significant parts of this internal document for the first time in this Smart Grid Strategy and provide a summary of it in our innovation strategy.
- The Information and Technology (IT) strategy, which includes a number of provisions to adopt existing solutions from our innovation portfolio which are coming to maturity and which also discusses wider architectural decisions. In this document we illustrate our architecture thinking related to one specific Smart Grid solution, Demand Side Response. We have a similar level of thinking in place for two others, Active Network Management, and LV and HV network visibility.
- Our Smart Metering strategy, which describes how we will ready our IT systems so that Smart Metering information can play a significant role alongside other Low-Voltage (LV) smart solutions in ensuring sufficient network capacity and improving outage management at this voltage level.
- Our Technical Losses strategy, which documents the guiding principles behind our decisions when specifying new plant or network investment generally. The increase or decrease of technical losses, where this is material, related to the implementation of individual Smart Grid technologies forms part of each individual cost-benefit analysis for each solution discussed in this document.
- The justification for our Load-Related Capital Expenditure in each of our three DNOs. Each justification document highlights individual schemes that have been replaced by Smart Grid solutions, but this document draws these into summary tables for all three of our licence areas.

2.2 Correspondence to Ofgem's requirements

The table below summarises where information can be found corresponding to each of the requirements related to Smart Grids in Ofgem's RIIO ED1 strategy decision document.

Table 1 Meeting the Decision document's expectations

Ofgem's requirements on innovation and smart grids	Where we cover these topics
Strategy for the deployment of smart grid solutions in RIIO-ED1	
This narrative should outline the type of smart solutions DNOs plan to deploy and the areas of expenditure e.g. IT systems or load related expenditure where the costs and benefits will materialise. It should also explain the DNOs' strategy for assessing the circumstances where they will deploy smart grid solutions as well as their internal processes to ensure that these circumstances are identified.	Our strategy for assessing the readiness and applicability of smart solutions is covered in the innovation strategy and our Smart Network Plan process is used where these have an impact which stretches across the company. Our record of the assessment, the modelling and impact of smart on our business plan is covered later in this Annex. Each of our policy decisions to deploy the Smart Grid solution has been subject to a Cost-Benefit Analysis (CBA).
Justification of smart using CBA Clearly demonstrate how they have considered alternative solutions in their cost benefit analysis in order to justify expenditure.	We have tested our policy frameworks for using smart solutions by performing cost-benefit calculations which have been performed using Ofgem's Cost-Benefit Analysis format; as presented in this document. Site specific justifications have been included in the Load-Related annexes for EPN, LPN and SPN, as part of this submission.
Intelligent Use of Data Set out a clear strategy for the intelligent use of data in their business alongside analysis demonstrating the cost of this data and supporting systems is outweighed by the benefits to customers.	Our most significant proposed investments associated with data are those associated with Smart Meters, which are set out and justified within our Smart Meter strategy.
Build on current learning to test new techniques Set out in the innovation strategy how they will build on current learning and smart grid deployment to test new techniques, including arrangements with customers and other parties in the value chain.	We are testing new techniques including new arrangements with customers as part of our innovation portfolio and projects. Especially Low Carbon London and Flexible Plug and Play, two of our LCNF projects, are built around this concept. We commit in this document to rely on Demand Side Response contracts in certain circumstances, and offer savings as a result.
How will smart grid strategy 'flex' under different scenarios This should outline the strategy DNOs will adopt to achieve the aggregate benefit of smart grids, which their analysis demonstrates is possible under each low carbon scenario. This strategy will need to explain how they will adapt their proposed strategy in different scenarios in order to deliver the benefits outlined.	Both our smart grid strategy and innovation strategy have been built with flexibility at its core; whether it is flexibility in timing, resources or which scenario to respond to. Both documents cover this in detail. The Future Network Development Plan 'ED1 Priorities' document specifically addresses how smart grid solution priorities will flex under different energy scenarios. Our commitment that customers will benefit from £141 million of savings compared with a 'conventional' business plan submission will remain under all scenarios. Should we achieve greater savings, these will be shared with customers through the regulatory mechanism.
How innovation is being embedded into the core business DNOs should explain how the outputs of the Innovation Funding Incentive (IFI) and the Low Carbon Network (LCN) Fund and other innovative solutions are being embedded into their core business. This can highlight where there are overlaps with the smart grid strategy i.e. where specific solutions they plan to deploy have come from LCN Fund projects. However, it should also provide details of wider innovation which would not necessarily be deemed as smart grids.	Our Innovation Strategy describes in detail how we take learning from both our own trials and from others and embed them in the business. We have a dedicated process, the Smart Network Plan, to streamline this for larger or more complicated solutions.
Strategy for meeting the challenges of RIIO-ED2 & ED3 This is the opportunity for DNOs to make the case for	Our Innovation Strategy is not bound to one period and is

Ofgem's requirements on innovation and smart grids	Where we cover these topics
investment in smart grids in RIIO-ED1 to provide future benefits. For instance, if the cost benefit analysis for smart grids in RIIO-ED1 indicates that there will be negative net benefits, this is an opportunity for DNOs to make the case that future benefits will outweigh these costs over the lifetime of the asset. This is likely to include justification for investment in enabling technologies such as IT systems, and explain how they can help DNOs make intelligent use of data. This narrative will need to be supported by a cost benefit analysis which is included in the business plan submission.	designed to cover the full low carbon transition; with our Roadmap to DSO (Future Network Development Plan) detailed all the steps that need to be taken and the flexibility around those steps. We discuss in this document the outcomes of the cost-benefit analyses that we have performed, in particular as it pertains to the benefit over different periods of time and seen by current customers and future customers.
Transform model solution assessment DNOs must use the Transform model to justify certain costs and narratives in their business plans. With appropriate justification DNOs are able to use other tools instead of the Transform model. Where DNOs are using the Transform model (and not an equivalent), they are required to submit a copy of the Proposed Parameters for the WS3/Transform Model document amended to set out the settings and assumptions they have used for each scenario, including justification.	The use of the Transform model in selecting our Smart Grid solutions is covered in chapter 5 of this document. An assessment of each individual solution of the Transform model is covered in chapter 6 and 7 of this document. None of the parameters of the Smart Grid solutions have been changed in the model from their 'as shipped' values. A cross-check of the global parameters used in the model against Ofgem's requirements is included in Appendix4.

3 Introducing our smart grid strategy

3.1 Introduction

‘The Carbon Plan’ (December 2011) sets out the overall framework for delivering UK’s low carbon future. Based on this Carbon Plan, DECC has presented four scenarios to 2030 quantifying prospective take-up levels and electricity consumption volumes for heat pumps and electric vehicles, distributed generation and micro-generation.

These obligations have major implications for the electricity supply industry (‘supply’ here meaning the whole of the physical electricity supply chain including generation, transmission, distribution, and even home use of electricity) and for the various market players who serve that chain. For distribution networks, this also means a paradigm shift from the current passive regime where power flows are unidirectional and very predictable. In future, intermittent forms of generation and the wider use of distributed energy resources will mean less predictable power flows, while major new applications for electricity (in particular electric vehicles and heat pumps) may result in up to a 19% increase in electricity consumption in 2030 compared with today, notwithstanding potential improvements in overall energy efficiency facilitated by smart metering.

If extensive reinforcement of distribution networks is to be avoided, which in turn would lead to unacceptable price increases for consumers as well as significant disruption due to street works, and risk damage to UK economic competitiveness, then smarter means of accommodating distributed energy resources combined with smarter management and control of electricity demand will be essential. In particular, demand management (leveraging flexible and responsive demand) will become a key tool for all market players, where increasingly the objective will be to balance demand and generation in real time and to ‘persuade’ demand to follow generation rather than vice-versa. This gives rise to the concept of ‘smart grids’ which will facilitate new technologies and commercial products to enable a much wider penetration of distributed generation from renewable or low carbon sources, and a major increase in electricity consumption from the electrification of heat and transport.

In recognition of the above, UK Power Networks has developed a Future Network Development Plan which forms our overall route map to becoming a Distribution System Operator (DSO) by deploying Smart Grid techniques. This provides the framework for UK Power Networks to deliver innovative solutions to achieve the following objectives:

- To be recognised as a low carbon leader - facilitating the decarbonisation of the electricity industry and playing our full part in enabling the electrification of heat and transport
- To deliver for its eight million customers, a secure, affordable, and environmentally sustainable electricity distribution system
- Our evolution to a truly smart distribution business, applying technological and commercial innovation to fulfil our regulatory commitment to develop, operate and maintain an efficient coordinated and economical system of electricity distribution

These objectives are entirely aligned with our corporate vision to be: an employer of choice; sustainably cost efficient; and a respected corporate citizen. The Route Map also outlines an implementation strategy based on the company’s relative strengths (particularly in the field of technological and commercial innovation) and the learning opportunities emanating from the Low Carbon Network Fund over the period 2010 to 2015.

Developing a Smart Grid strategy is a fundamental prerequisite to dealing with the immediate challenges our business will face over the next 10 years and to ultimately becoming a DSO.

3.1.1 Climate and energy landscape

In July 2009, the UK Government published 'The UK Low Carbon Transition Plan'. A number of supporting strategies accompanied the publication of this Energy White Paper, including:

- The UK Renewable Energy Strategy – Department of Energy and Climate Change (DECC)
- Low Carbon Transport: A Greener Future – Department for Transport (DfT)
- The UK Low Carbon Industrial Strategy – Department for Business Innovation and Skills (BIS)

In December 2011 these documents were effectively combined under The Carbon Plan which sets out the overall framework for delivering UK's low carbon future.

These documents set out the roadmap for UK to achieve its key objectives and binding targets surrounding:

- Greenhouse gas emissions
- Energy efficiency
- Renewable energy
- With regard to renewable energy in particular, the UK has committed to 15% of all energy consumed being derived from renewable sources by 2020. Electricity will necessarily bear the brunt of delivering this target with heat and transport making important but smaller contributions. The Government's lead scenario suggests:
- More than 30% of electricity (117TWh pa) generated from renewables
- 12% of heat (72TWh pa) generated from renewables
- 10% of transport (49TWh pa) from renewables

DECC has subsequently proposed energy scenarios that will meet the '4th Carbon Budget' (1,950 Mt CO_2e) obligation which is to reduce carbon emissions compared with 1990 levels by 50% over the period 2023 to 2027. These 4th Carbon Budget scenarios have been the basis for studying future network impacts of low carbon technologies under Smart Grid Forum WS3 referred to in Section 1.2.8.

To deliver these contributions will require a significant increase in intermittent low carbon generation (mainly transmission connected wind generation but including embedded wind and solar generation and heat-led CHP) and electrification of both heat and transport, for example through heat pumps and electric vehicles. A higher level of penetration of distributed and micro-generation has been catalysed by the Feed-in Tariff which came into effect in April 2010 providing fiscal stimuli for generators of up to 5MWe capacity, while the Renewable Heat Incentive, which became effective for residential properties in Autumn 2012 is expected to encourage the wider and more rapid adoption of heat pumps.

Meanwhile, a complementary initiative, the Green Deal, again available since autumn 2012, creates a new financing mechanism to allow a range of energy efficiency measures, such as loft insulation or heating controls, to be installed in people's homes and businesses at no upfront cost.

In December 2010 the Government issued a consultation white paper on Electricity Market Reform, which included four specific proposals:

- Carbon price support to provide greater long-term certainty around the additional cost of running polluting plant
- Feed-in tariffs (FITs) with contracts for differences (CfD) to provide long-term contracts giving more certainty on the revenues for low-carbon generation (while retaining an incentive for efficiency) and to make clean energy investment even more attractive
- Capacity payments to encourage security of supply through the construction of flexible reserve plants or demand reduction measures to ensure supply security during a period wherein generation plant margin will decrease due to decommissioning of first generation nuclear plant and Large Combustion Plant Directive non-compliant coal fired power stations
- An emissions performance standard to limit the amount of carbon that the most carbon intensive power stations can emit
- Market reform could have a significant impact on the viability of smart grid solutions involving interactions with consumers. On that basis, UK Power Networks initially considered 5 potential electricity growth scenarios over the ED1 period, each based on credible permutations of economic growth, impact of low carbon technologies, and progress with market reform

Table 2 Possible future energy scenarios

	Rate of economic growth	Impact of low carbon technologies	Impact of electricity market reform
Engaged Green Society	High	High	High
Green Tech Revolution	High	High	Low
Green Stimulus	Low	High	High
Business As Usual	High	Low	Low
Economic Concern	Low	Low	High

Of these five scenarios, Green Technology Revolution was originally regarded as the most appropriate to consider from an ED1 planning perspective.

However, following extensive stakeholder consultation, a hybrid scenario has been adopted which takes a more conservative approach in a number of areas including assumptions around the rate of take-up of low carbon technologies. In summary, the hybrid scenario modifies downwards our earlier forecasts for household growth; domestic rate of take-up of heat pumps; and uptake rates for electric vehicles but now includes consideration of commercial heat pumps and new information from DEFRA's Market Transformation Programme regarding domestic lighting and appliances. This has resulted in the planning inputs and assumptions summarised in the table below.

Table 3 UK Power Networks' updated core business scenario

	November 2012 Consultation Business Plan			Business Plan Update		
	LPN	EPN	SPN	LPN	EPN	SPN
Heat pumps – Domestic	61k	233k	121k	37k	222k	84k
Heat pumps – Non domestic (MW)	Not included	Not included	Not included	62MW	155MW	82MW
Electric vehicles	130k	243k	156k	41k	129k	111k
FIT eligible generation	93k	290k	167k	67k	195k	113k
Onshore wind (MW)	10MW	724MW	214MW	10MW	625MW	145MW
Offshore wind (MW)	N/A	Beyond 2015 assumed to connect to offshore grid	Beyond 2015 assumed to connect to offshore grid	Not applicable	Beyond 2015 assumed to connect to offshore grid	Beyond 2015 assumed to connect to offshore grid

As such, our core business scenario which is fully quantified lies roughly on the axis between the two qualitative scenarios Green Stimulus and Business As Usual which have been used to assess solutions in our Future Network Development Plan. We are conscious that any delay in the uptake of Low Carbon Technologies would take us closer to a Business As Usual scenario. However, even in a Business As Usual scenario, our commitment to increase our reliance on Smart Grid techniques will remain.

3.1.2 Definition of smart grid

If extensive reinforcement of distribution networks is to be avoided then smarter means of accommodating distributed energy resources combined with smarter management and control of electricity demand will be essential.

This gives rise to the concept of 'smart grids' which will facilitate new technologies and commercial products to enable a much wider penetration of distributed generation from renewable or low carbon sources, and a major increase in electricity consumption from the electrification of heat and transport. A smart grid can be defined as:

"An electricity power system which can significantly 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".

3.1.3 Characteristics of a smart grid

A smart grid would be characterised by:

- Smart technologies to economically enhance the service quality, reliability, security and safety of the electricity supply system
- An enhanced information communications system to provide greater end-to-end visibility of the utilisation and condition of the network
- The economic connection of low/zero-carbon distributed generation and energy resources - from industrial/commercial to domestic scale
- Smart power flow, storage, voltage, power factor and fault level management strategies to permit the higher utilisation of distribution networks
- Smart management of flexible/responsive demand to improve load factor, minimise losses, and create additional capacity headroom
- Strategies to minimise the peak network loading impact of heat pumps and electric vehicles by leveraging embedded storage opportunities

The table in Appendix A summarises UK Power Networks' envisaged ED1 Smart Grid deliverables and the indicative timing of each deliverable over the ED1 period. In practice, these timings will depend partly on the electricity scenario that emerges over the period (particularly with regard to low carbon technology take up and market development) and largely on the degree of development of smart grid technologies currently at relatively low technology readiness levels. The timings below are based on UK Power Networks' ED1 core scenario which assumes a modest return (by 2015) to economic growth and low carbon technology take up, but relatively slow progress with market development. A high-level overview of the same table on ED1 Deliverables can be found in the Innovation Strategy document.

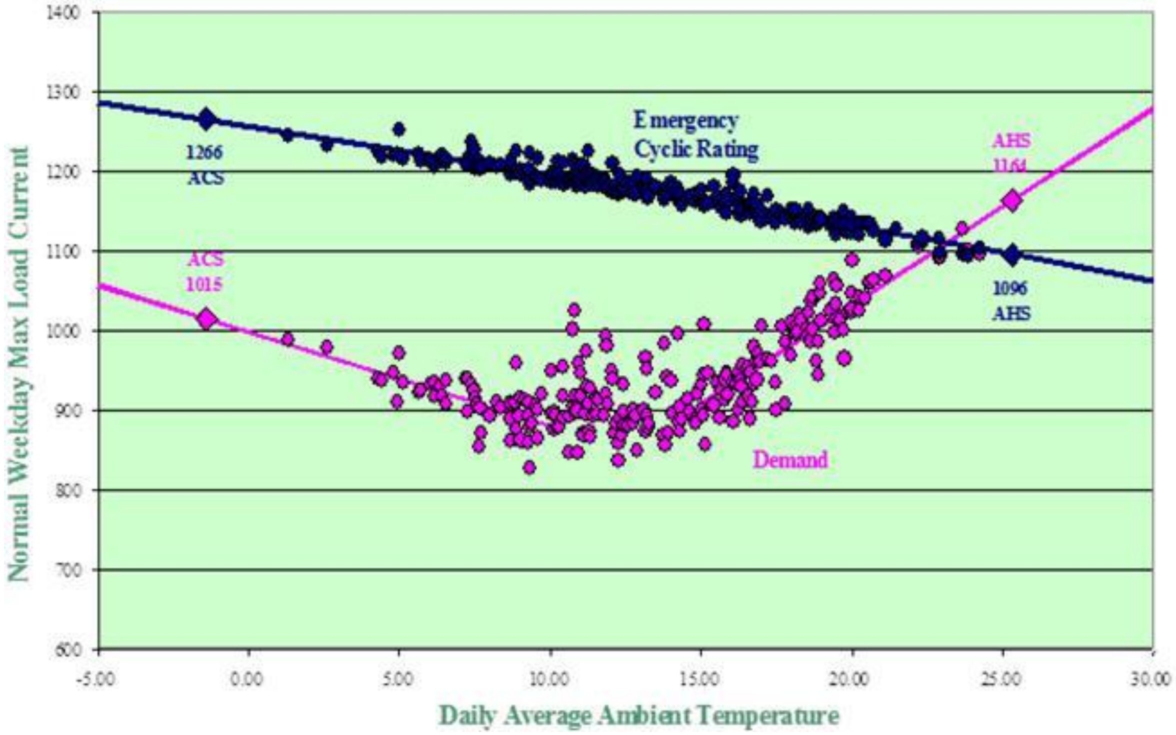
3.2 The areas and ways in which we are already running a smart grid

Notwithstanding our continuous research and development of innovative engineering technologies and commercial products, there are already a number of advanced techniques which are now firmly established as 'business as usual' practices, some of which are enabling us to develop even 'smarter' solutions. The following describes two specific examples:

Thermal Modelling of System Transformers and Real-Time Thermal Rating

Section 5.6.1 of this annexe describes how our advanced thermal modelling of transformer winding temperature has enabled us to operate main and primary substations (132/11kV and 33/11kV substations, and voltage variations thereof) at higher levels of utilisation, and hence safely incorporate a higher level of 'energy at risk' than many of our peer DNOs in determining the threshold at which a substation load index (LI) would increase from one level to the next (for example LI4 to LI5).The diagram below shows the results of a typical analysis, in which the increased demand in cold temperatures due to electric heating and the increased demand in warmer temperatures due to comfort cooling can be seen. We estimate that our practice of running the network at this higher level of energy at risk is potentially saving customers around £15 million across our three licence areas over a price control period such as RIIO ED1, compared with setting a policy of lower utilisation.

Figure 2 Typical results of thermal modelling illustrating impact of ambient temperature and demand on Transformer ECR

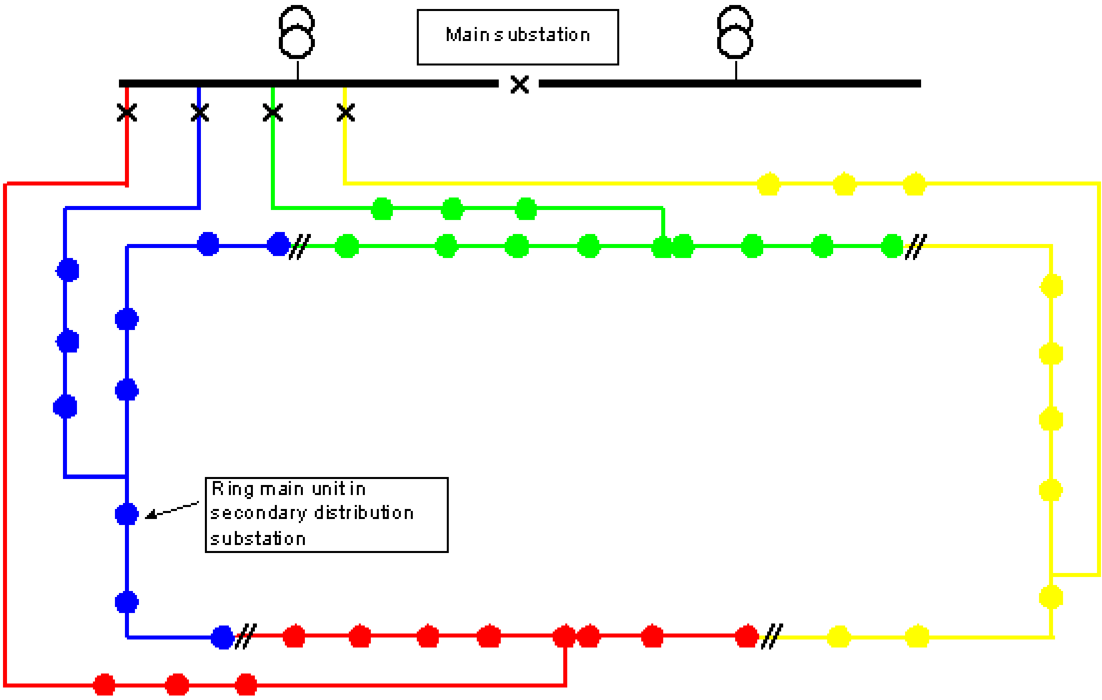


Typical results of thermal modelling illustrating impact of ambient temperature and demand on Transformer ECR

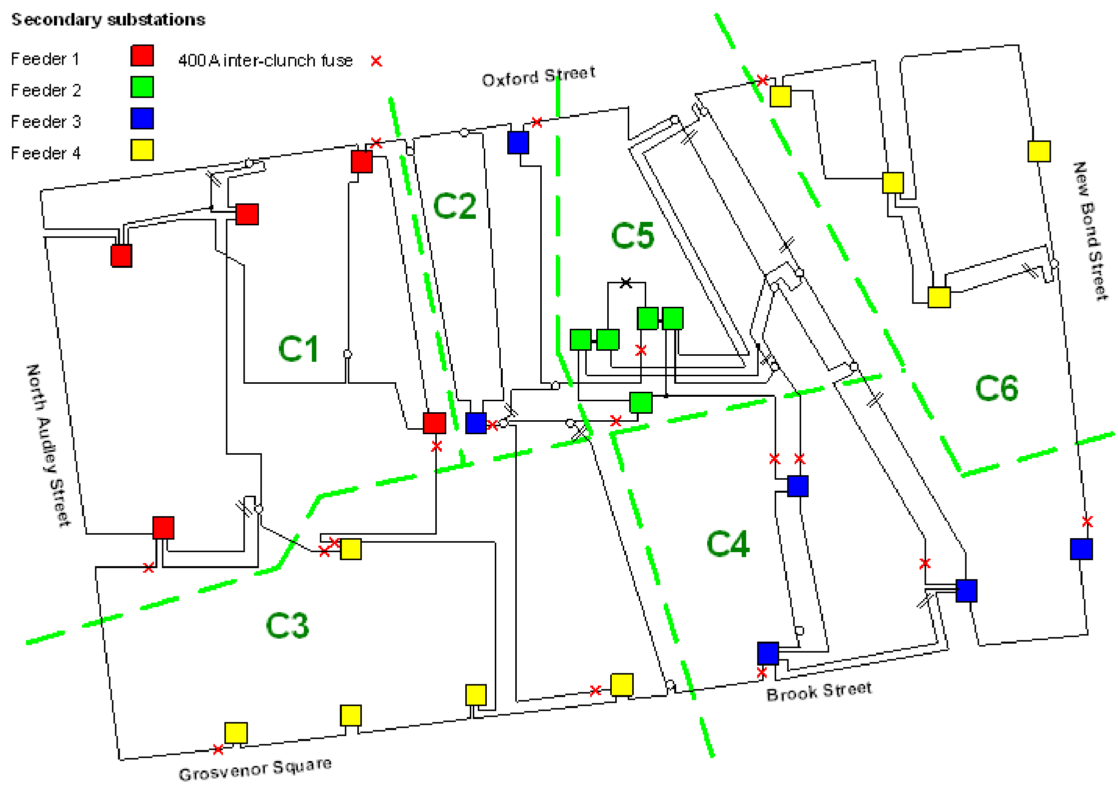
Our development of, and experience in applying, this technique enables us to now take a further step in maximising transformer ratings and hence capacity utilisation. This next step is to now apply real-time thermal rating (RTTR) techniques where this is anticipated to deliver a minimum of three years deferral of reinforcement. By selectively applying RTTR to a number of highly utilised transformers we anticipate deferring 20 main or primary substation reinforcement schemes from the ED1 to the ED2 period with a net (of RTTR costs) saving of some £15 million (see 5.6.2).

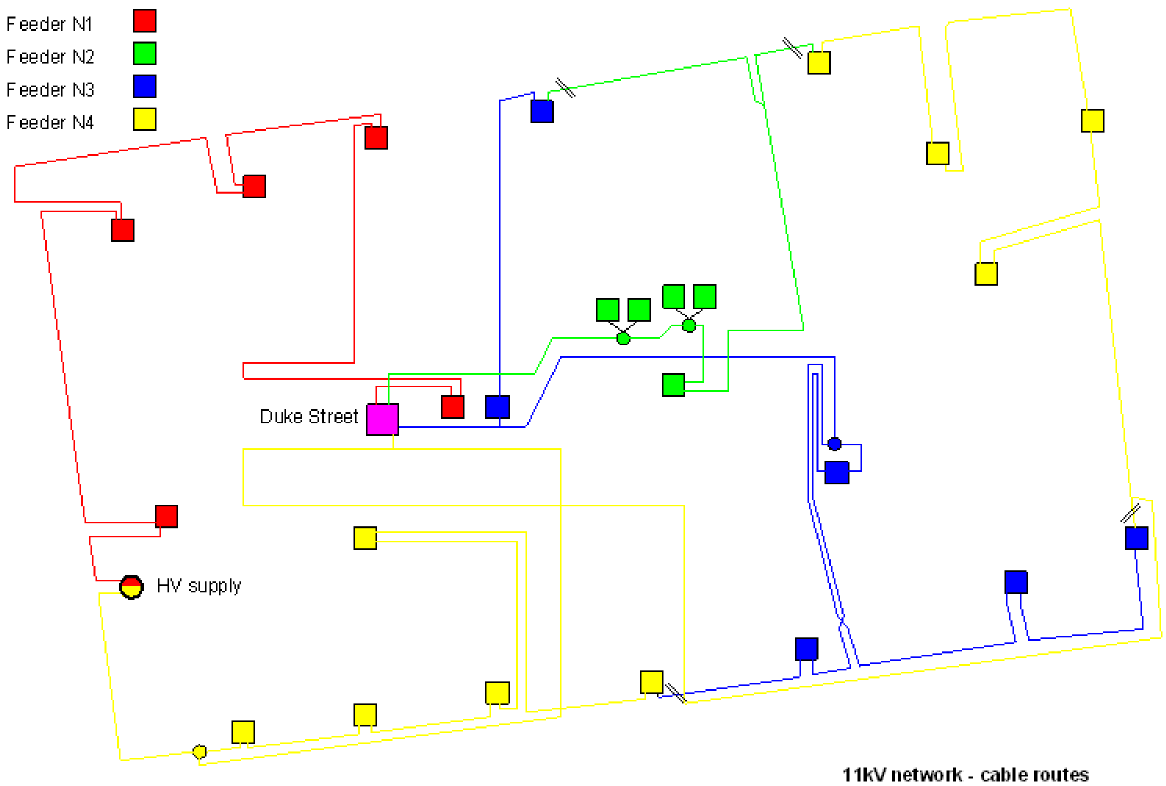
LPN Interconnected Network and Enhanced Meshing

Our LPN HV (11kV and 6.6kV) network is based on a unique legacy design principle which incorporates closed LV interconnection of the HV system. There are numerous variations on the design principle but the general arrangement is for typically four 11kV feeders to be operated as a feeder group supplied from a common 11kV busbar source. The individual 11kV feeders are operated as a radial ring with four injection points. Each of the four sections of the HV ring is electrically separated by a normal open point as the schematic diagram below shows.

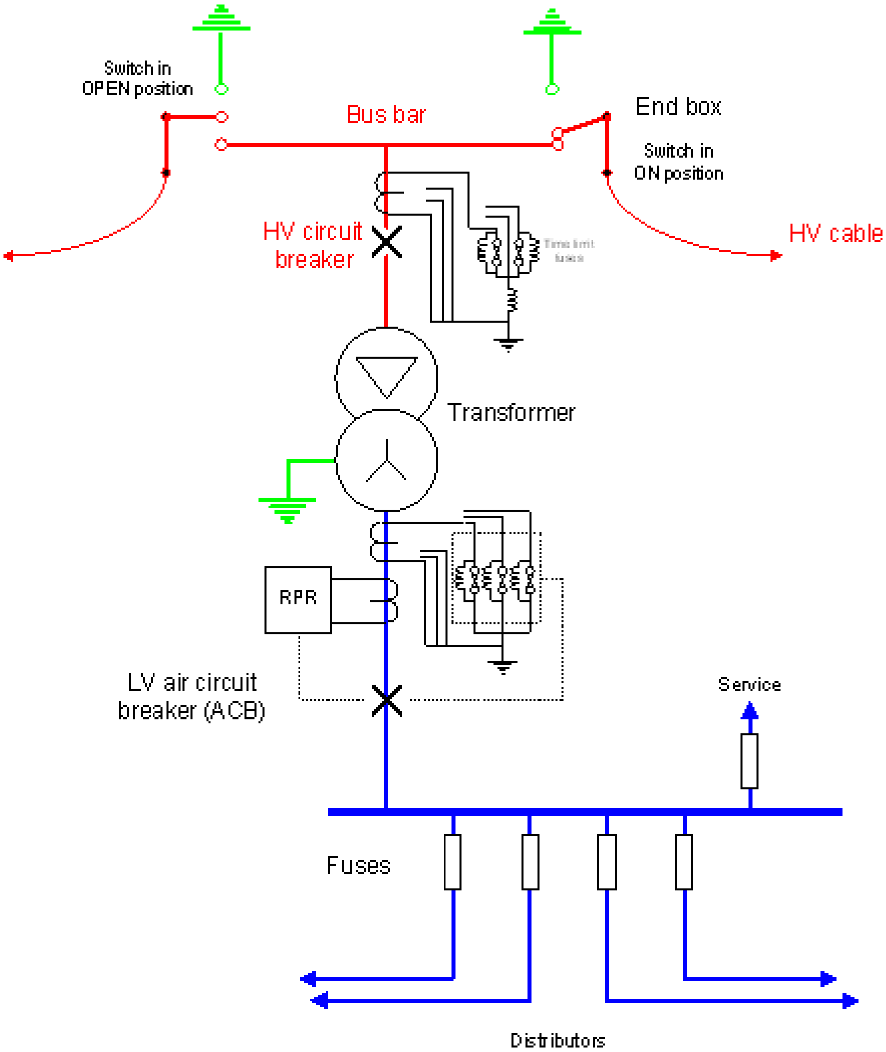


The original design principle, which is still applied to much of the Central London network, is for the LV networks supplied by the substations associated with the four feeder groups to be operated in parallel such that in the event of a loss of one 11kV feeder from the group due to a fault, the LV busbars at all the substations supplied by that feeder will remain energised through the LV interconnected circuits. The following diagrams illustrate firstly the LV interconnection arrangements for an actual example of such a network and secondly the routes of the associated HV feeder groups.





In the event of an 11kV fault, the LV network is prevented from feeding back onto the faulted 11kV network by means of protection applied to each 11kV / LV transformer circuit breaker.



This arrangement allows for very high circuit utilisation levels, since each 11kV circuit (for a four feeder group) can be loaded to 75% of its thermal capacity (or 80% for a five-feeder group) as opposed to 50% for a conventional radial network and still remain compliant with the requirements of ER P2/6 for a class B demand group. A further significant benefit (especially in a central business district) is that consumers served by an LV interconnected HV system suffer no loss of supply in the event of a single 11kV fault.

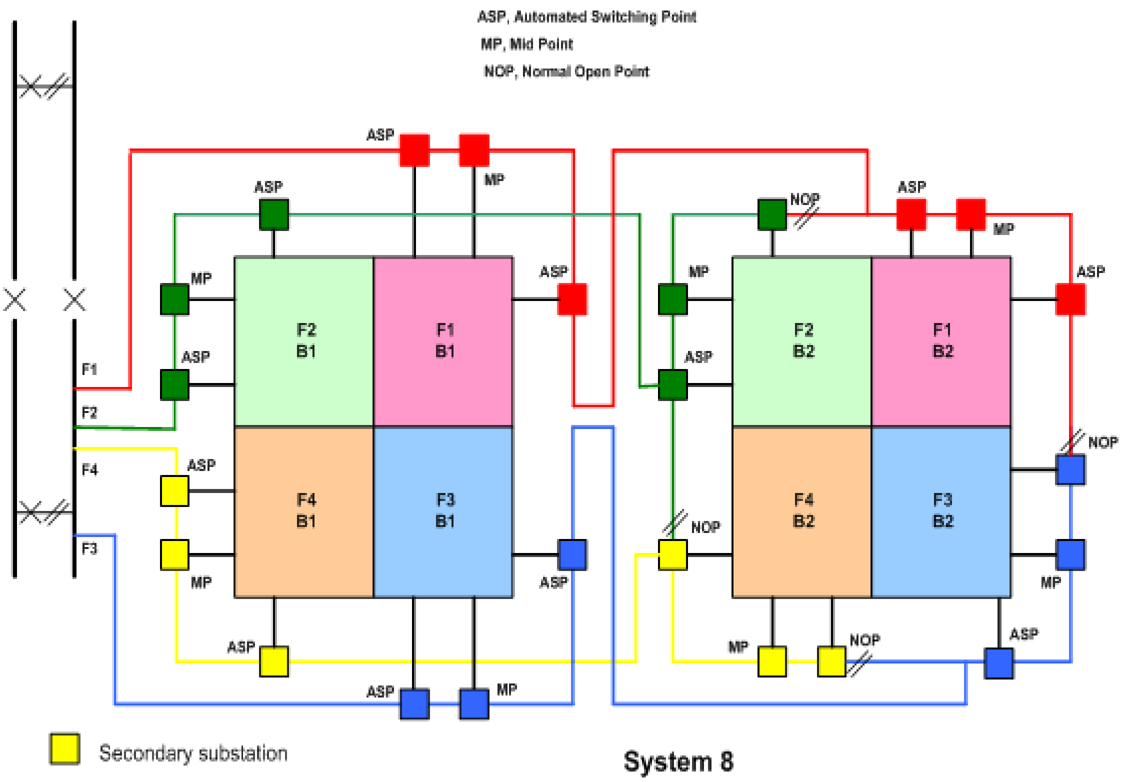
It follows that consumers enjoy an equivalent level of supply security to that of a unit-protected ring whilst also benefitting from the cost-efficiency associated with a higher level of circuit utilisation (unit-protected rings having to be limited to 50% utilisation) as well as the avoided cost of 11kV feeder circuit breakers and pilot wire protection schemes associated with unit-protected circuits.

Despite this very efficient meshing technique, we do not claim this saving in our assessment of smart grid savings - even though 'network meshing' (even temporary network meshing) is a common solution selected by the SGF WS3 Transform model. It will be appreciated that temporary network meshing (for example simply paralleling two HV feeders and equipping them with remote control for more rapid post-fault restoration) is a far less sophisticated solution conferring neither the higher circuit utilisation benefits nor the 'no-break' supply security of the LV-interconnected HV feeder group arrangement.

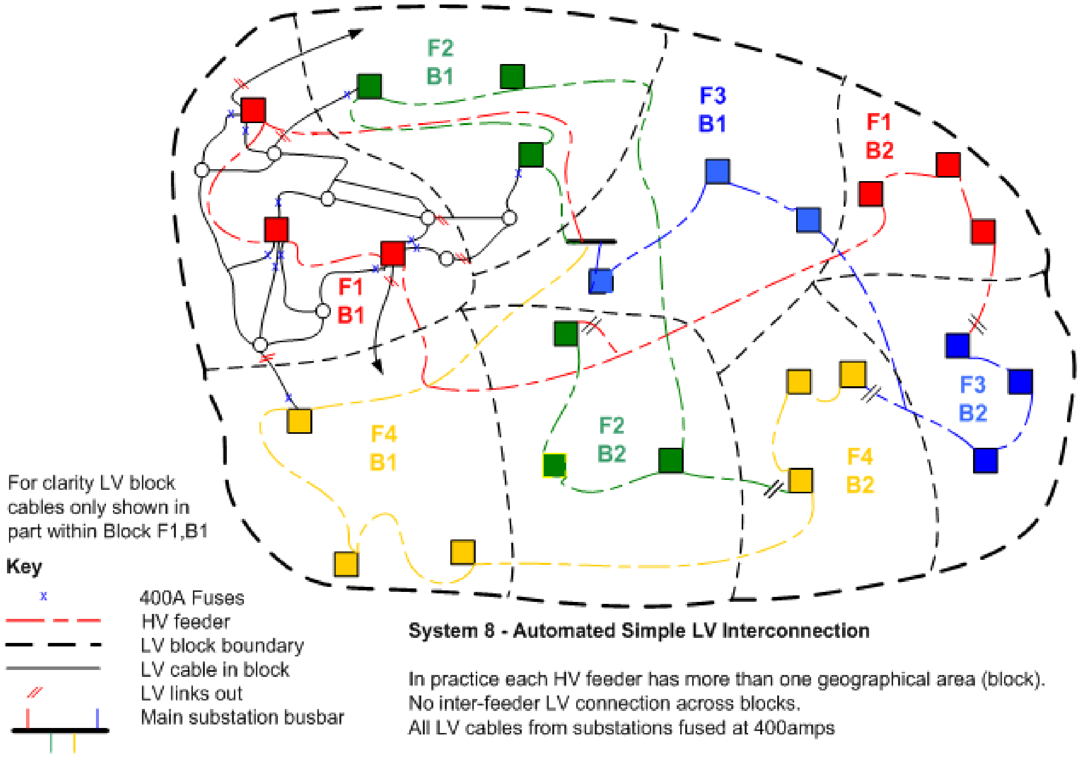
However, due to increasing levels of demand growth in the Central London area (which have hitherto been efficiently accommodated due to the high levels of utilisation described above) it has become necessary to deviate from the original design principle for a number of HV feeder groups. Due to the now much higher LV circuit loadings, the LV network has on occasions failed to successfully support the HV feeder group in the event of an 11kV fault. This can lead to prolonged restorations of supply as ‘rebuilding’ the LV network following cascade fuse operations has to be undertaken in stages until the LV interconnection is re-established, and this procedure can begin only once the 11kV fault has been isolated through HV switching.

In order to address this problem without losing the inherent benefits of the LV interconnected HV feeder group system, in terms of high utilisation, a number of hybrid systems have been developed. One of these, which we name ‘System 8’, retains simple LV interconnection between substations associated with the same HV circuit of a feeder group but now incorporates HV automation within the feeder group such that 11kV faults can be automatically isolated and supplies restored to the great majority of substations through automated HV switching within 3 minutes. In the case of those few substations whose 11kV busbars remain de-energised following automated HV switching, supplies to consumers are immediately restored through the simplified LV interconnection (i.e. from immediately adjacent substations as soon as their 11kV busbars are re-energised through automated switching).

The following diagrams show firstly the schematic arrangement of a typical ‘System 8’ network and secondly the geographic dispositions of the HV and LV circuits.



System 8



System 8 - Automated Simple LV Interconnection

In practice each HV feeder has more than one geographical area (block).
No inter-feeder LV connection across blocks.
All LV cables from substations fused at 400amps

This arrangement ensures that the benefits of high utilisation are retained and, although consumers will no longer benefit from a no-break supply, they will normally experience supply interruptions of no more than 3 minutes. Maintaining our policy of applying this enhanced meshing technique has a substantial benefit over alternative solutions - which would be to either reinforce the feeder groups through 11kV injection (i.e. introducing a fifth and perhaps sixth HV feeder into the group, which would be impractical in many cases due to main substation busbar limitations) and/or reinforce the LV interconnection (also largely impractical due to cost and public disruption due to street works).

We therefore regard this enhanced meshing technique as a truly ‘smart’ solution. It is more sophisticated than most concepts of ‘network meshing’ and, as explained above, retains very high levels of circuit utilisation and quality of supply performance that would not be feasible with typical network meshing at this voltage level. Over the ED1 period, we propose some £29m of enhanced network meshing solutions. We estimate that these may have cost as much as £44m, or £15m more, had we opted to change our design policy and carry out any of the alternatives discussed above.

3.3 Role of demand side response

Given the pressures on electricity distribution networks arising from new sources of electricity demand, less predictable load profiles, and greater volatility (and less predictability) in market spot prices for electricity, demand side response will play an increasingly important role, both in balancing the wider system, and in addressing local (distribution) network constraints.

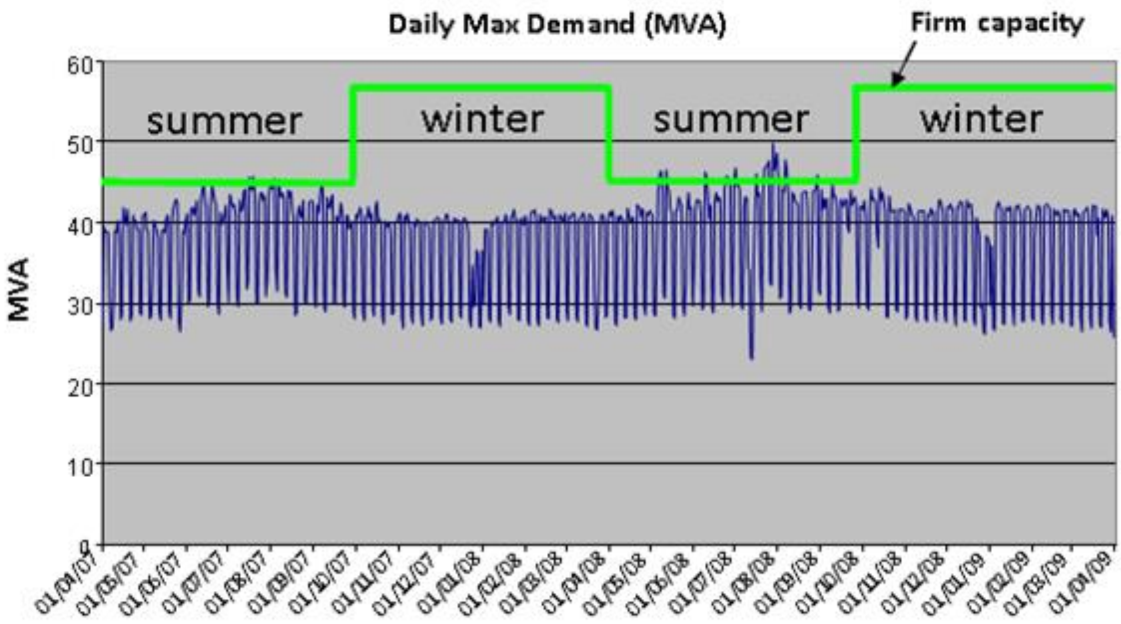
Moreover, while Suppliers might currently seem to have the natural monopoly on demand side management (DSM) as a means of optimising and balancing their portfolios, it is important to recognise that Demand Side Response (DSR) - essentially a contracted ancillary service which provides demand reduction in response to a dispatch or tariff price change signal - will become increasingly attractive as a residual balancing tool to National Grid, acting as National Electricity System Operator (NETSO) for the main interconnected transmission system and the interconnectors, and to DNOs as a means of minimising the need for network reinforcement to maintain levels of supply security specified by ER P2/6.

We recognise that there is the potential for conflicts between market players (e.g. DNOs and Suppliers). However, at the higher voltage levels (more specifically for ER P2/6 demand groups C, D and E) there is scope for innovation in bilateral DSR commercial arrangements with major customers (or groups of customers) which could significantly reduce energy at risk from arranged or unplanned network outages and/or could defer or avoid the need for major reinforcement to maintain ER P2/6 compliance.

Networks which might benefit from bilateral DSR contracts could include those which at one extreme are at risk due to relatively high (but short duration) demand peaks above firm capacity; or at the other extreme are at risk due to moderate peaks above firm capacity but for sustained periods. The scope for DSR ancillary services can be appreciated from the chart below which depicts a classic 4x15MVA 33/11kV Main Substation serving a commercial area with a typical summer peaking annual demand profile.

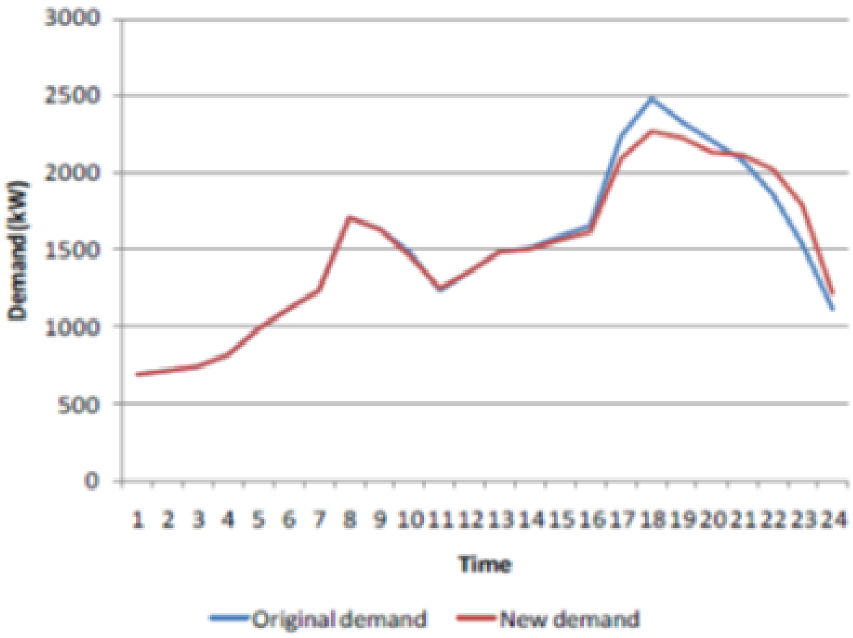
During the winter period, there is ample firm capacity headroom since a 30% uplift can be applied to the 15MVA transformer cyclic ratings giving a firm capacity of (3 x 15 x 1.3) 58.5MVA. However, in the summer period, no such uplift can be applied and hence the firm capacity reduces to 45MVA. The summer peak weekday demand periodically exceeds the firm capacity of the substation leaving the substation out-of-firm during such periods. In the absence of adequate (and sufficiently fast) post-fault load transfer capability, the substation or adjacent primary infrastructure might require significant reinforcement to restore firm capacity. On the other hand, if a DSR ancillary service could be procured from one or more commercial consumers such that in the event of an unplanned outage, demand could be reduced quickly (say within 20 minutes) and shifted to a later period of the day, then this could be sufficient to prevent the internal hot-spot winding temperature of the remaining three transformers reaching a level sufficient to initiate a winding temperature initiated protection trip.

Figure 3 Representation of an annual demand profile for a central London Main Substation

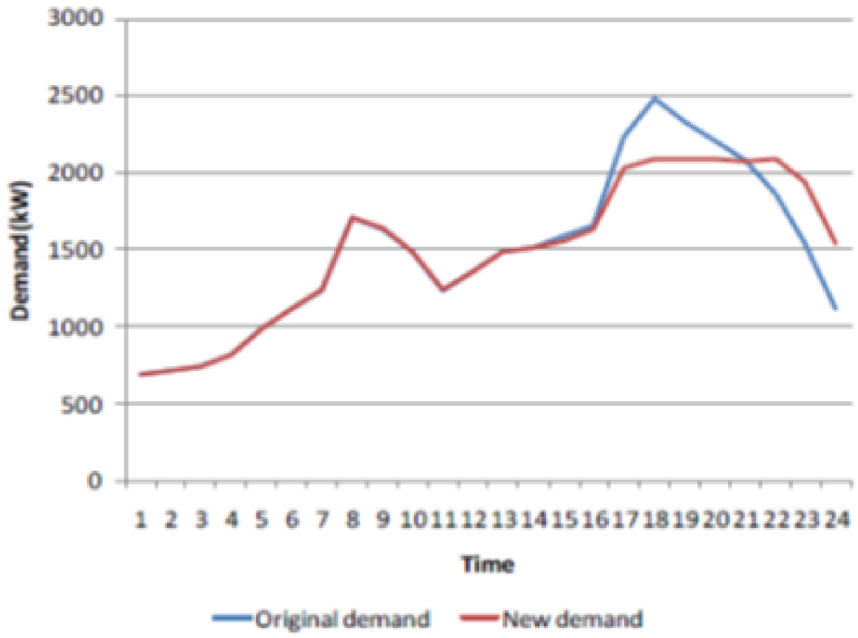


Ancillary services might also be realised without recourse to bilateral or multipartite contracts. For example smart meters, which will be installed in virtually all domestic properties and most SME premises by 2020, will ultimately be capable of supporting time of use or critical peak pricing tariffs, encouraging consumers to switch demand to non-peak times of day. The more flexible the demand, the greater will be its value as a potential ancillary service. For example 'wet' appliances such as washing machines, dish washers and tumble dryers are flexible in the sense that they can be programmed to operate when electricity demand is low and hence prices in future should be lower. The charts below illustrate the current potential for peak demand reduction through 'wet' appliances on a network serving 2.5MW of winter weekday peak demand, or approximately 1,250 homes, both at current levels of usage and with full penetration.

Figure 4 Current and potential available peak demand reduction from 'wet' appliances



(present situation)



(full penetration)

Electric vehicles are also very flexible in this sense due to their embedded electrical storage (i.e. the EV battery). Heat pumps are also capable of flexible operation if installed in a very well insulated home (where ambient temperature changes are very gradual) or when associated with thermal storage such as a hot water tank.

3.4 Role of technology

The successful development and application of technology is essential to the development of Smart Grids. The Future Network Development Plan (Appendices A, B and C) describe 12 Smart Grid Products / Functions; these are:

- System Monitoring
- System Automation
- Fault Level Management
- Voltage / Power Factor Control
- Electrical Energy Storage
- Distributed Generation Management
- Distributed Energy Resources Management (including micro-generation)
- Multi-Rate Time-of-Use Tariffs
- Balancing Services
- Distribution Network Constraint Management / Security Support / Optimisation
- Network Management / Support Systems
- Information Communications Systems

Each of the Products / Functions comprises a series of Technology Applications (which may be engineering or commercially based).

Technology Applications will generally be the result of new smart grid products and/or the product of proven prototypes trialled under IFI or LCNF projects. As can be seen from the Future Network Development Plan (Appendices A, B and C) the range of available technologies is already extensive, and reference to UK Power Networks' annual IFI/LCN report will provide a good insight into technologies currently under development.

Future Network Development Plan - High Level Use Cases (Appendix B) describes all of the Technology Applications considered relevant and viable in addressing the identified Products / Functions, together with their potential network application, methodology, need and benefit, and their potential scope over four specific periods, namely: 2015-2019; 2019-2023; 2023-2030; and 2030-2050. These periods align with ED1 (and the interim review point); DECC's 4th Carbon Budget scenarios (to 2030) and the longer term goal of cutting CO_2 emissions by 80% compared with 1990 levels by 2050.

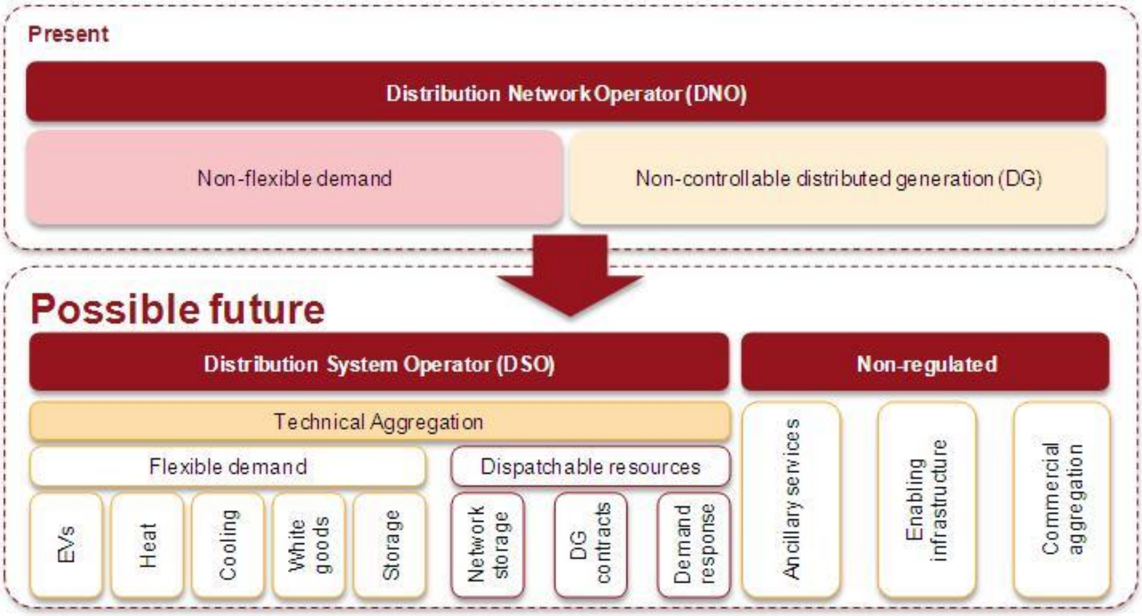
Successful application of new Smart Grid technologies will be essential to ensuring the future distribution network is operating to its full potential in a safe and sustainable way. It will also be essential that UK Power Networks remains at the forefront of technological development as this will be critical to maintaining satisfactory business performance and to delivering shareholders' expectations in terms of justifiable returns on investment through capital efficiency and regulatory incentives. It follows that as part of our future role as a DSO it will be essential to continue to develop new Technology Applications through the current IFI/LCNF funding mechanisms and through the proposed (for RIIO ED1) Network Innovation Allowance and Network Innovation Competition , as set out in our Innovation Strategy.

Future Network Development Plan - RIIO ED1 Priorities (Appendix A) describes priorities for Technology Applications under each Smart Grid Product / Function and, in addition, R&D priorities.

3.5 Transition from distribution network operator to distribution system operator

It follows from the above that the traditional role of the DNO as a largely passive network operator will need to evolve to that of an active 'system' operator leveraging both engineering technology and commercial acumen to manage a more active and highly utilised network. A Distribution System Operator (DSO) takes advantage of the network benefits of smart grid technology, and commercial incentives on consumers but with full awareness of the wider 'whole system' role for responsive demand, electrical storage and dispatchable generation The DSO concept is illustrated by the diagram below:

Figure 5 Transition from DNO to DSO



A **Distribution Network Operator (DNO)** continues to build in response to growth in maximum or peak demand. A DNO does not have the ability or desire to influence demand and generation, and tends to introduce flexibility only to the extent that it supports existing regulatory priorities (such as to reduce supply interruptions and the risk of catastrophic asset failure).

By contrast, a **Distribution System Operator (DSO)** has access to a portfolio of responsive demand, storage and controllable generation assets that can be used to actively contribute to both distribution network and wider system operation. A DSO builds and operates a flexible network with the ability to control load flows on its network. The combination of a highly flexible network and access to demand and generation response allows the DSO to contribute to the increasing UK-wide challenge of encouraging demand to follow generation.

3.5.1 DSO Route Map and Products

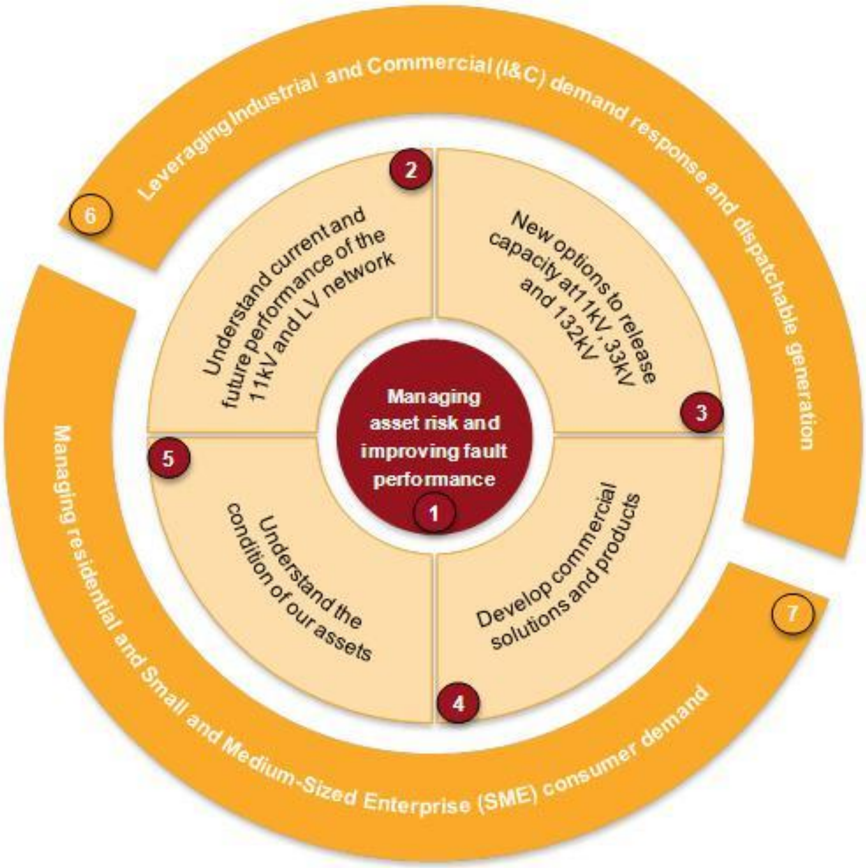
The overall Route Map comprises a series of seven individual maps each designed around a central business goal or engineering outcome, each of which is expected to be a high priority in the coming price controls RIIO ED1 and RIIO ED2.

The route maps are defined around six key products, each of which is described by a statement of ambition. The six products are shown below: they consist of four sectors in the centre of the diagram which are largely internalised products and two areas of visible engagement with the wider customer community represented by the outer split concentric ring.

In some cases, the engagement is facilitated by the key sectors in the centre of the diagram: an example is 'leveraging I&C demand response and dispatchable generation' which is improved the more UK Power Networks is able to demonstrate flexibility in releasing or developing capacity at 11kV, 33kV and 132kV.

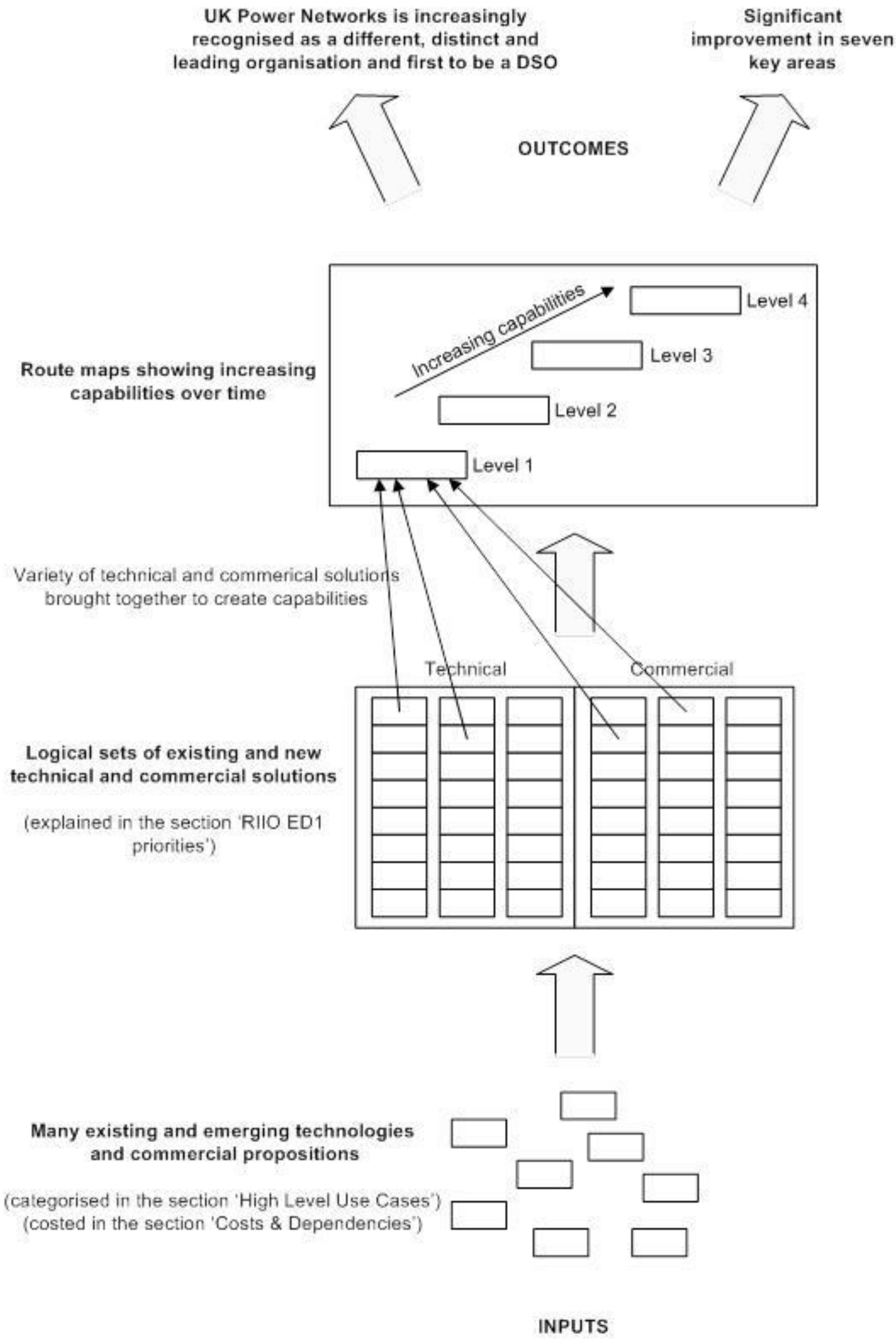
In other cases, the engagement is a pre-requisite for the key central areas to be able to perform: for example, if UK Power Networks is to 'develop (successful) commercial solutions and products' that will be reliant on good relationships with either business or residential customers who are able and minded to provide an ancillary service.

Figure 6 Innovation themes



Each route map is illustrated in the Future Network Development Plan as a staircase or ladder by which our capability to deliver the output builds step-by-step, with each new level of capability building on the previous step. At each step, our capability is built by drawing on a combination of existing and new technical and commercial solutions. Each route map emphasises an increasing ability to accommodate and optimise a combination of technical and commercial solutions, which is the key characteristic of an organisation operating as a DSO. This is illustrated in the diagram below.

Figure 7 The structured approach in our Future Network Development Plan



The following diagram illustrates how the DSO products support the defined primary ED1 outputs as well as Operational and Capital Efficiency, the benefits of which will be shared between shareholders and consumers.

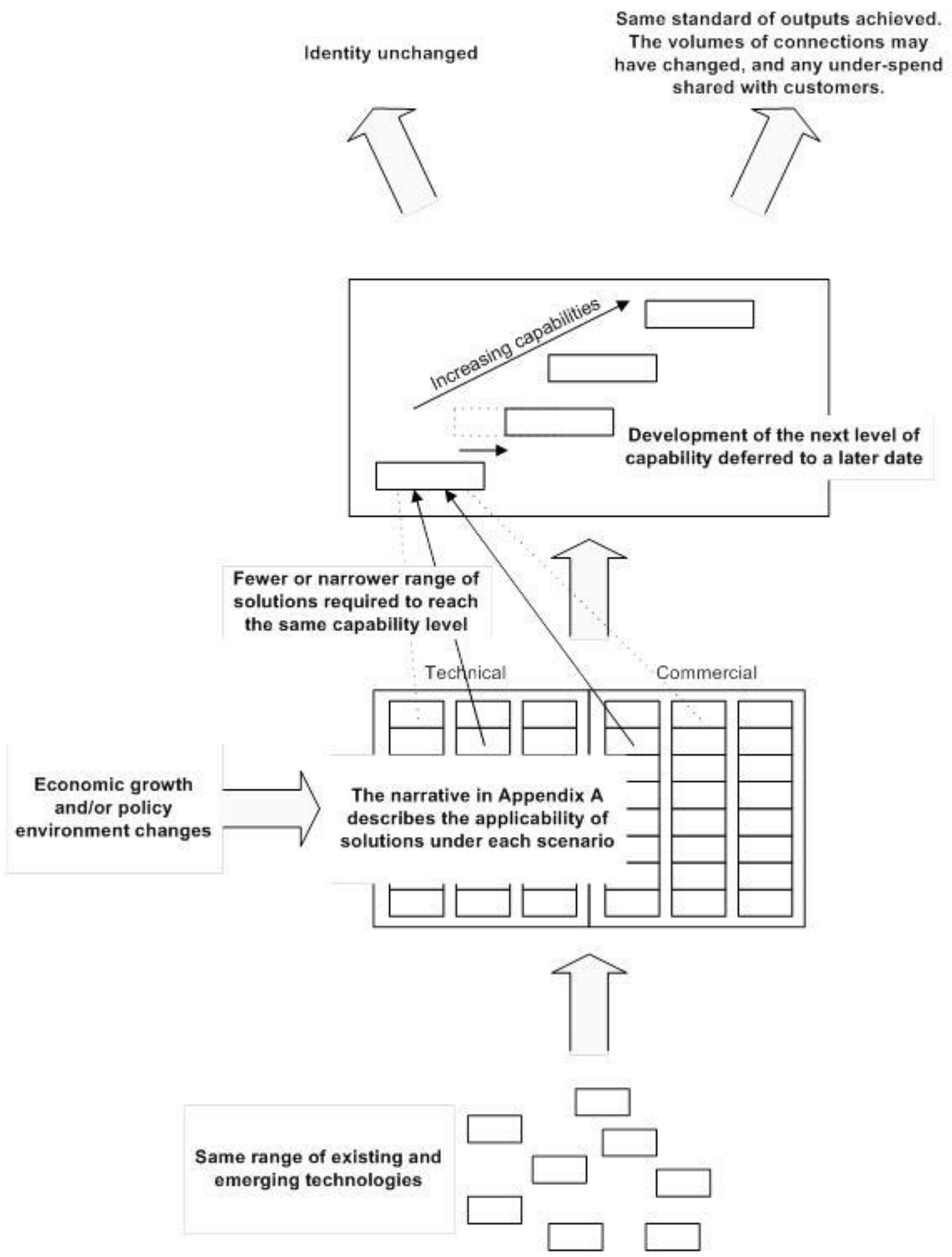
Output categories	Capability themes: Leveraging I&C DSR and DG	Understand performance of 11kV and LV network	New options to release capacity at 11/33/132kV	Understand the condition of our assets	Develop commercial solutions and products	Managing residential and SME consumer demand	Managing asset risk and improving fault performance
Capital efficiency	●	●	●	●	●	●	
Reliability & availability				●			●
Operational efficiency		●		●			
Connections	●		●				
Driving sustainable networks	●	●	●		●	●	
Customer satisfaction			●	●		●	●
Environment			●	●			●
Safety				●	●		●
Social obligations							●

The full catalogue of technical and commercial solutions on which UK Power Networks might need to draw on over the ED1 and ED2 periods, including those which may not emerge but which are discussed in the industry, can be found in the ‘Future Network Development Plan - High Level Use Cases’ - Appendix B. These are then brought together into logical sets of solutions in the ‘Future Network Development Plan - ED1 Priorities’ - Appendix A, where they are described in more detail with notes on their applicability and maturity. The route maps then bring elements of the solution sets together to create capabilities. The route maps not only consist of adopting solutions, but also a re-positioning of our business priorities, skill-set and training.

The detail provided in the ‘Future Network Development Plan - ED1 Priorities’ - Appendix A allows us to revise our business plan if external events change. This is illustrated in the diagram below. In the example shown, a change in the economic environment leads UK Power Networks to conclude that the plan representing lowest cost to future customers will be achieved by delaying the introduction of a new technology, since the need for that technology will now materialise later. The route maps are intended to facilitate a healthy debate about the capabilities which are essential to develop, and when these capabilities must be in place, especially in the context of economic and policy conditions which might change.

This approach has culminated in a list of deliverables which we published in Chapter 6 of our Innovation Strategy which customers can expect to see coming to fruition as a result of both our work to date on innovation and as a result of our RIIO-ED1 innovation activities. To make the process clearer, we have included the same deliverables table in this document as Appendix A. The version in Appendix A includes additional detail drawn from the appendices of the Future Network Development Plan, specifically further comments on what the solution achieves (the ‘Network application’ and ‘Methodology’ columns in the table), and our qualitative assessment of business readiness as well as our judgement of its ‘formal’ Technology Readiness Level (TRL).

Figure 8 How the structure approach allows us to respond to change



3.6 Smart grid forum alignment

In this first part of the document, we have summarised our Smart Grid strategy and the way in which it allows us to be flexible to accommodate different scenarios. We have referred to the detail in our Future Network Development Plan, and the structured approach which it takes in documenting and assessing technologies.

In implementing and delivering the Smart Grid solutions listed in the second part of this document it will also be essential to remain aligned with developments in a number of industry forums - particularly the Ofgem / DECC joint chaired Smart Grid Forum (SGF) and its associated work streams (WS). The following is a brief overview of the activities of the SGF WSs:

- **SGF WS1** led by DECC has developed the assumptions and scenarios necessary for the network companies to produce business plans that are consistent with The Carbon Plan. The output of this work has been four specified scenarios concerning the take-up, over the period to 2030, of electric vehicles, heat pumps, distributed generation and micro-generation. Each of these scenarios is aligned with the UK's 4^{th} Carbon Budget in terms of achieving reduced carbon emission targets
- **SGF WS2** led by Ofgem has developed an evaluation framework that is able to assess, at high level, alternative network development options, in particular to help inform policy decisions related to smart grids. This has essentially been a precursor to SGF WS3 below.
- **SGF WS3** has been tasked with building on the high-level WS2 study which reported a positive business case for GB adopting a smart grid strategy. SGF WS3's task has been to undertake detailed analyses to assess the impact of low carbon technologies on Great Britain's electricity distribution networks and assess the network investment implications. This work has been informed by the scenarios created by SGF WS1.
- SGF WS3 delivered, in April 2013, its final report describing investment requirements against each of the WS1 scenarios under three different intervention strategies: business as usual, incremental smart and top-down smart. WS3 has also produced three supporting reports: tipping point analysis, enabler mapping and least regrets investment, and an investment decision support tool 'Transform'. SGF WS3 is to now adopt a new governance role, the focus of which will be to periodically refine the operation of the Transform model based on proposals put forward by users (principally, but not limited to, DNOs) and to update the Transform model based on any new information surrounding the effectiveness of smart grid solutions, for example from experience gained through IFI or LCNF projects.
- **SGF WS4** has hitherto focussed on ensuring that the GB Smart Meter programme is aligned, in terms of metering system functional specification, with the requirements of a smart grid.
- **SGF WS5,** which considers how the Forum can best pursue its objectives and communicates effectively with stakeholders, has focused to date on creating through the ENA a smart grid learning portal providing a single point of access to the outcomes of IFI and LCNF projects.
- **SGF WS6** has a comprehensive forward programme to investigate and address possible regulatory / licence or commercial / market barriers to the effective delivery of smart grid interventions, and to investigate possible hurdles to an effective DNO to DSO transition. This work will be particularly important in understanding both the scope for new commercial options such as Demand Side Response and Generator Network Support, and the scope for leveraging the full business value from energy storage.
- **SGF WS7** - Planning and Operating a Distribution network in 2030 – is a new workstream that will investigate the wider system planning and operational implications of a future low carbon mix of electricity generation, and will consider issues such as the effects of lower system inertia on steady-state, dynamic and transient stability.

UK Power Networks is directly involved with the Smart Grid Forum, including each of the above-mentioned workstreams and will continue to provide direction to, as well as accumulate knowledge emanating from, the work of these workstreams. Learning derived from these workstreams will be incorporated within, and continuously refresh, our own Innovation Strategy.

4 How we built Smart Grid into our plan

4.1 Introduction

We listed in the first part of the document the characteristics of a Smart Grid. In the second part of the document, we explain how our internal Smart Grid strategy has been used to make decisions about the Smart Grid options which could be built into our business plan with associated cost savings against them, and which could be committed to be rolled-out to connections customers over the RIIO-ED1 period.

As we submit our business plan for the RIIO ED1 period, Smart Grid solutions have the potential to:

- Reduce the cost of reinforcement on the network in response to increasing demand
- Provide a greater range of options and allow us to hold back on making certain investment decisions until the load uptake is clearer
- Provide flexibility in the event that low-carbon uptake or demand uptake is faster than we had planned for
- Reduce the cost and/or speed with which generation in particular can connect to our network
- Improve the reliability of our network performance
- Reduce the cost associated with asset replacement, whilst not affecting the performance of the assets

The diagram on the next page shows the process by which we built Smart Grid solutions into our business plan, and particularly as this relates to the cost of reinforcing the network. The scenarios and our internal Smart Grid strategy described in Part 1 of this document were instrumental in this process. Since its introduction at the end of 2009, the Future Network Development Plan has established a structured, qualitative assessment of the maturity of Smart Grid solutions and their importance in addressing the challenges that UK Power Networks faces.

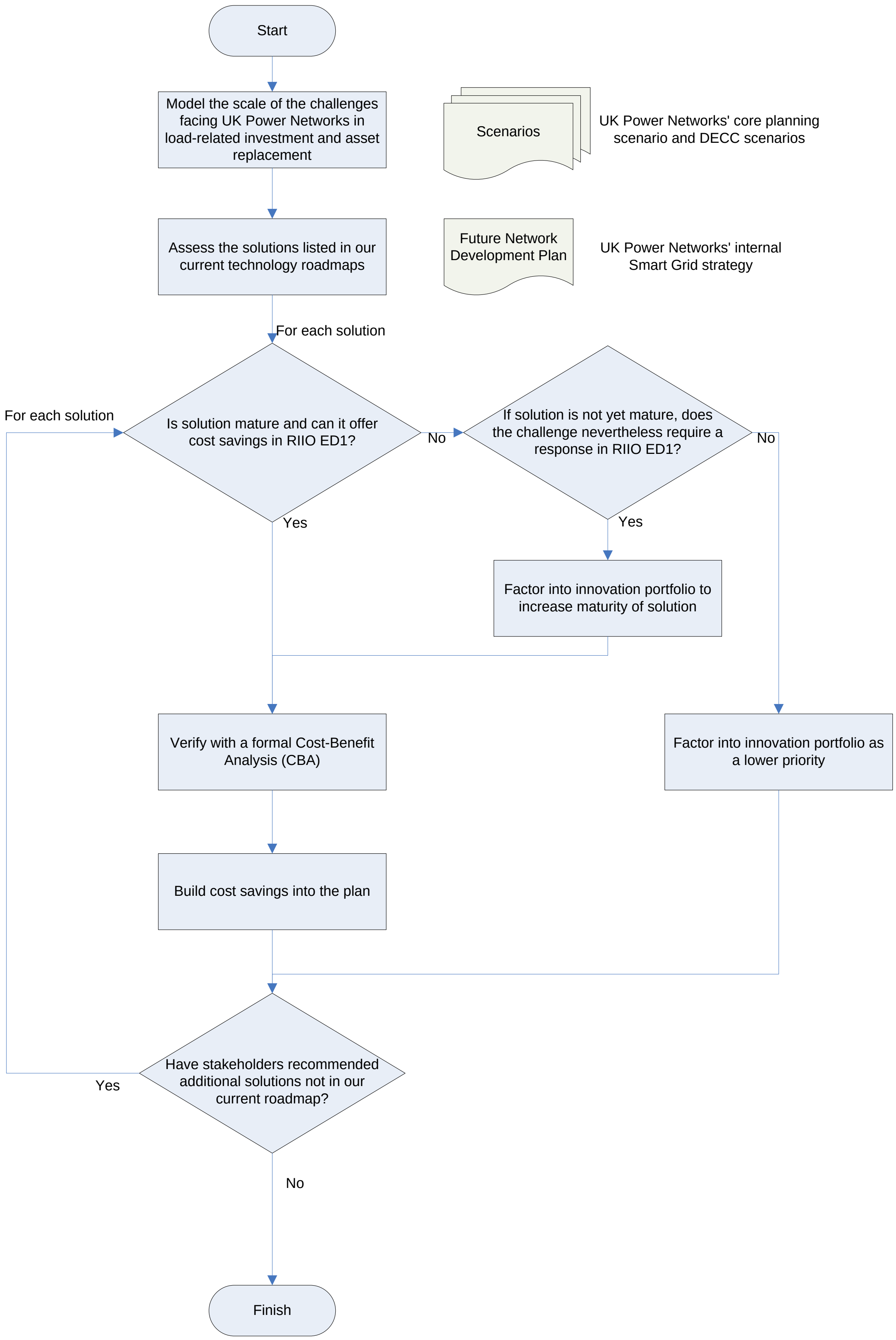
Two significant tools have allowed us to take this qualitative analysis further and to carry out quantitative analysis: the Transform model developed by the UK DNOs under the auspices of the Smart Grid Forum Workstream 3, and a Load-Related Expenditure (LRE) model developed for us by Imperial College. These models are discussed in detail in chapter 6. As an example, these tools have allowed us to model the potential impact that an increasing number of Electric Vehicles (EVs), micro-generation and heat pumps connected at the domestic level may have on the performance of our Low Voltage (LV) networks.

Armed with quantified assessments of challenges arising, such as that on the LV network, and with the existing rolling investment plan which is maintained by our network planning engineers with a 5-10 year time horizon, we have been able to assess the technologies currently in our roadmaps for inclusion in the plan. The remainder of this document is dedicated to explaining the rationale for the inclusion of each of the Smart Grid technologies which are built into our business plan. In each case, the technology was chosen for inclusion either because experience from our own or other DNOs' Innovation Funding Incentive and Low Carbon Network Fund projects gave us the confidence that the solution is mature and can provide cost savings, or because it was clear that the scale of the challenge requires us to find alternative Smart Grid solutions within the RIIO ED1 period, even if these may not be mature at the time of writing. This was particularly the case for the challenge associated with Low Voltage reinforcement, an area in which a number of DNOs' LCNF projects are ramping up but have not yet delivered a mature toolkit of solutions.

The narrative describing each solution also provide details of the Cost-Benefit Analysis which was carried out in each case in order to ensure that solutions delivered a whole-life benefit to current and future customers.

The final step in our process ensured that we took account of input from our stakeholders where they suggested technologies which were not on our current technology roadmap but could provide significant benefit. A particular example of this was Real-time Thermal Rating of transformers, which was particularly cited in an independent report which we commissioned from John Scott of Chiltern Power, which reviewed our innovation strategy and Smart Grid deployments.

Figure 9 Decision process by which smart grid technologies were built into our plan



4.2 Site-specific solutions as opposed to volume forecasts

It is important to note that there is a difference in the way that we plan solutions for implementation on the 'primary' network (in UK Power Networks' case, at voltage levels of 20kV and above) and for implementation on the 'secondary' network (in UK Power Networks' case, at low voltage (LV), 6.6kV and 11kV).

In the case of the primary network, our investment plans are based on site-by-site studies of substations and individual circuits. These site-by-site studies are carried out by our planning engineers against our core planning scenario and then tested globally by computer model runs of different scenarios. Cost savings are, in general, named against particular reinforcement or replacement projects and particular sites.

In the case of the secondary network, our future investment plans are built on forecasts of the volume of work which may be required on the network in response to uptake in load. Whilst our core scenario does provide predictions down to postcode level, the volume of interventions on the secondary network are an order of magnitude of larger than the primary network. All our work on the secondary network is therefore based on the forecast volumes of activities that will be required and their associated cost and manpower.

The benefit for customers is the same in both cases: where UK Power Networks builds cost savings into its plans compared to the amount forecast either from site-by-site analysis or from models of the volumes of activity, then UK Power Networks is committing to deliver the same reliability and available capacity but for less of customers' money.

The Smart Grid solutions implemented at the primary level do, however, lend themselves to more detailed site-by-site assurance checks, such as our use of Light Detection and Ranging (LIDAR) surveys discussed in the following section.

4.3 Our approach to cost-benefit analysis

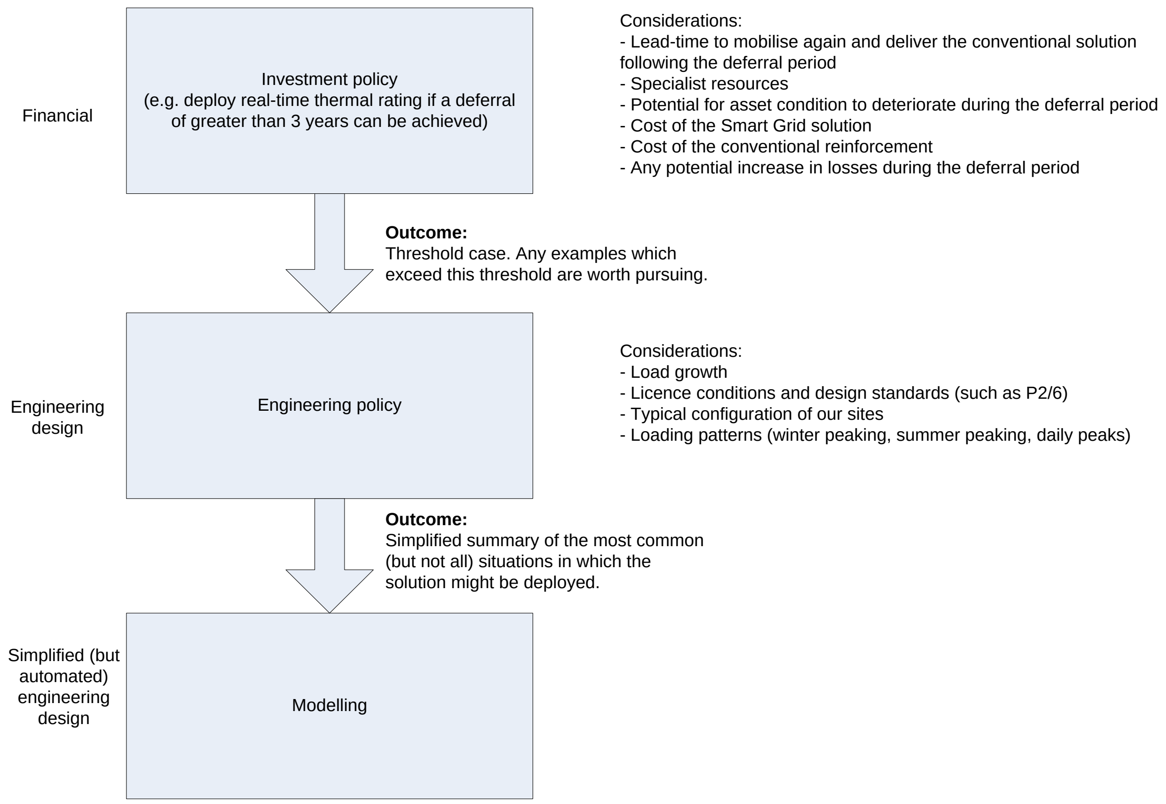
Clearly Smart Grid solutions should only be deployed where they demonstrate a net benefit for current and future customers. There may be instances in which they are slightly more expensive in the short term but make a compelling case that they leave our options open, enabling us to react to changes in the economic and policy environment.

The diagram on the following page outlines our approach. In the first instance, we concentrate on our investment policy. At the investment policy level, there is typically only a link to the type or nature of conventional reinforcement which is being deferred, and not to any specifics of individual substation sites. The focus is financial.

The investment policy takes into account the varied nature of conventional reinforcement. For example, the time required to mobilise to re-conductor a 132kV overhead line is significantly longer than the time taken to mobilise works on a low voltage or 11kV urban network. Similarly, the workforce both within UK Power Networks and contractors is more specialised in the case of the 132kV overhead line, and there may be fewer contracting options available. For this reason, the tendency will be for an investment policy on 132kV overhead lines to only consider Smart Grid solutions which defer the works by 5 years or more, since the lead time to mobilise the conventional works is in itself of the order of 12 months, and our flexibility to react if the economic environment changes is less.

Other considerations come into play, however: even though it may be easier to mobilise work and stay flexible at the lower voltages, and so it may be attractive to consider options with shorter deferral periods, there is a corresponding risk that the Smart Grid solution may become 'stranded' after a short deferral period. Therefore this may tend to push up once again the deferral period which is viable.

Figure 10 Process for testing applicability of smart solution



Having taken these considerations into account in each of the areas in which we are seeking to avoid reinforcement, we are able to provide an investment policy for that area, and which has been subject to a rigorous cost-benefit analysis. At this stage, this does not state at which proportion of sites this may be applied, but simply provides confidence that any instances which pass this investment 'threshold' by deferring for longer than the expected period, or deferring a larger conventional scheme with the same Smart Grid solution, are beneficial to customers.

In order to understand the number of instances in which we can apply the Smart Grid technique and meet this investment threshold, two factors are required; the model of load growth, which determines how the strain on the Smart Grid solution is building during the deferral period, and the design rules for resilience which our network needs to meet.

At this point, we are able, based on the load growth estimate, to identify the engineering applications in which the Smart Grid technology can be deployed and will automatically meet the investment threshold discussed above. As an example, we show later in the document that Demand Side Response can be deployed in instances in which load growth does not push a primary substation site beyond 10% of its firm capacity, knowing that this meets our investment policy.

Finally, it is possible to some extent to automate the identification of potential sites at which to deploy Smart Grid solutions, by our use of modelling tools. A model such as the Imperial Load Related Expenditure (LRE) model is primarily an electrical network modelling tool, allowing us to model a larger section of the network and under more scenarios than ever before. However, we recognise that it is best used when concentrating on the most common engineering applications which meet the investment policy, and our network planners may identify additional cases which meet the investment policy over and above those identified by the model; and secondly, that it does not carry out cost-benefit analysis, which we carry out separately in forming the investment policy itself.

Based on this approach, in the remainder of the document against each solution we will present the investment policy which drove the use of the Smart Grid solution; the main engineering applications which meet the policy; and the numerical results of the cost-benefit analysis.

4.4 Example of CBA assessment

In line with Ofgem's requirements we have carried out cost-benefit analysis (CBA) over time periods of 16 years (two price control periods), 24 years (three price control periods), 32 years (four price control periods) and 45 years. The CBA provides a figure for the Net Present Value (NPV) of the investing in the Smart Grid approach as opposed to following the conventional approach.

If a '-' represents a negative NPV, and a '+' a positive NPV, and '++' and '- - ' strongly positive and negative, then we interpret these results as follows:

CBA period:	16 yrs	24 yrs	32 yrs	45 yrs	Interpretation
Example #1	++	+	+	+	Introduces flexibility and optionality Strong early savings. The Smart Grid solutions may enable current customers to benefit even further if the load uptake does not materialise and the conventional reinforcement is deferred even further.
Example #2	++	+	Neutral	Neutral	Flexibility is worthwhile in its own right The solution is long-term net neutral but the flexibility in the early years is worthwhile in its own right. Note that this typically implies that UK Power Networks is sacrificing the opportunity to increase its regulated asset value (RAV) in the interest of keeping our options open.
Example #3	++	+	-	-	Flexibility and potential for further benefits The solution based on its currently quantified benefits has strong benefit in providing flexibility in the early years, but may be challenged over the long run. However, there is potential for additional benefits that have not been quantified.
Example #4	+	+	+	+	Good potential for saving, little optionality There is a net benefit from deploying the Smart Grid solution. However, high up-front costs of the Smart Grid solution mean that there is less benefit in its ability to keep our options open.

Throughout the document we will identify the category into which each Smart Grid solution falls.

5 Summary of smart grid solutions

Before providing detail of the individual Smart Grid solutions, this section provides a summary of the Smart Grid solutions built into our business plan. It is particularly directed to readers who are looking to cross-reference the cost savings discussed in the Executive Summary of our business plan, and to readers who are looking to cross-reference with our Business Plan Data Template (BPDT).

5.1 Executive summary

The table below summarises the cost savings that have been built into our reinforcement plans as a result of applying Smart Grid solutions. The first of these was discussed earlier in Part 1 and represents the Smart Grid solutions which are already in our working practice and accruing benefits for customers. It consists of £15 million of accrued benefits in our LPN licence area from maintaining our meshed network approach, and an estimated £5 million of accrued benefit in each licence area from our approach to transformer utilisation. Each of the remaining solution categories will be discussed in further detail in the remainder of the document. Also discussed, but not presented here, are the Smart Grid solutions which will help generation customers connect more rapidly or cost-effectively to the network – this table excludes the impact of Smart on the cost of new connections.

Table 4 Executive summary of smart savings in our UK Power Networks' business plan

Smart Grid solution	EPN	LPN	SPN	all DNOs	Running total
Benefit from existing Smart Grid network designs and practices	£5m	£20m	£5m	£30m	£30m
Savings in LV reinforcement compared to forecast volumes	£11.8m	£9.9m	£13.4m	£35.1m	£65.1m
Saving from Demand Side Response schemes	£11.8m	£13.9m	£17.7m	£43.4m	£108.5
Savings in overhead line reinforcements	£8.6m	-	-	£8.6m	£117.1m
Savings from Dynamic Transformer ratings	£7.7m	£3.1m	£4.2m	£15.0m	£132.1m
Savings from Partial Discharge monitoring of switchgear	£1.9m	£2.5m	£4.6m	£9.0m	£141.1m
Sum of savings	£46.8m	£49.4m	£44.9m	£141.1m	£141.1m

5.2 References to Business Plan Data Template (BPDT)

Table 5 on the next page gives a more detailed overview of the Smart Grid solutions considered in our plan, and also introduces the structure in which we will discuss the Smart Grid solutions in the remainder of this document.

The savings in Low Voltage (LV) reinforcement are targeted both at reinforcement which would have been triggered due to voltage issues (either micro-generation pushing voltage higher than has traditionally been expected or high point demands such as Electric Vehicles bring voltage down) and reinforcement which would have been triggered due to the rating of plant ('thermal constraints').

Table 5 Our analysis of the smart grid solutions

Smart Grid solution	Primary driver	RIGS table reference	Need case identified by	Costs taken from	Cost benefit analysis tool	Displaces
Voltage management solutions at low voltage (LV)						
EAVC – LV circuit	Low Carbon Technology (LCT) uptake, specifically micro-generation, heat pump and Electric Vehicle uptake at domestic premises	CV103 row 43	LRE model	Transform	Transform	Reinforcement of LV cables and/or splitting of circuits and installation of HV/LV transformers mid-circuit
EAVC – LV point-of-connection			LRE model	Transform	Transform	
LV switched capacitors		CV103 row 46	LRE model	Transform	Transform	
LV D-FACTS		CV103 row 35	LRE model	Transform	Transform	
LV STATCOM			LRE model	Transform	Transform	
Management of thermal constraints at Low Voltage (LV) and/or High Voltage to Low Voltage (HV/LV) transformation						
ANM – LV	Low Carbon Technology (LCT) uptake, specifically heat pump and Electric Vehicle uptake at residential premises	CV103 row 34	LRE model	Transform	Transform	Meshing solutions and/or establishment of additional HV/LV substations
LV temporary meshing		CV103 row 44	LRE model	Transform	Transform	Establishment of additional HV/LV substations to bring capacity into the area
Permanent meshing LV urban		CV103 row 43	LRE model	Transform	Transform	
Permanent meshing LV suburban			LRE model	Transform	Transform	
RTTR for HV/LV Trafos		CV103 row 45	LRE model	Transform	Transform	Replacement of transformer with higher capacity transformer
Demand and generation response						
D(G)SR	Load uptake triggered either by LCT uptake or conventional load growth	CV101	LRE model and PLEs	Based on experienc e from the	Ofgem CBA tool	Establishment of new primary substations and/or up-rating of transformers or circuits

Smart Grid solution	Primary driver	RIGS table reference	Need case identified by	Costs taken from	Cost benefit analysis tool	Displaces
D(G)SR	Maintaining security of supply during works	CV101	LRE model and PLEs	STOR market and Low Carbon London trials		Construction of load transfer schemes
Overhead lines						
Up-rating to new (static) rating	Load uptake triggered either by LCT uptake or conventional load growth	CV101	LIDAR survey	UK Power Networks' unit costs	Ofgem CBA tool	Re-conductoring of line
Real-time thermal rating	Speed of connection and cost of connection for generation customers	CV17 rows 22, 23, 43, 44	LRE model	Manfr's quotation	Calculated at the time of connection offer	Re-conductoring of line or connection to a more distant circuit or substation with available capacity
Dynamic rating of system transformers	Load uptake triggered either by LCT uptake or conventional load growth	CV103 row 66	LRE model	Manfr's quotation	Ofgem CBA tool	Replacement of transformer with higher capacity transformer
Partial discharge monitoring	Optimisation of asset replacement	CV3 rows 32-46 and 69-76	ARP tool	Manfr's quotation	Ofgem CBA tool	Replacement of circuit breakers and/or switchboard
Active Network Management (ANM) – ANM EHV	Speed of connection and cost of connection for generation customers	CV17 rows 22, 23, 43, 44	LRE model	Manfr's quotation	Calculated at the time of connection offer	Connection to a more distant substation with available firm capacity or substation upgrades to increase firm capacity

We have applied Demand Side Response in a number of different scenarios, both to defer reinforcement and to maintain security of supply. Once again, our commitment to the financial stretch in Table 4 makes no assumption or requirement at this stage whether this is delivered from demand-side (DSR) or generation-side response (GSR). As discussed in our Smart Meter strategy, we expect that a proportion of this will be delivered from residential customers equipped with Smart Meters, but concentrate in the first instance on Industrial & Commercial (I&C) customers.

We discuss below Smart Grid solutions to assist in increasing capacity on overhead lines, and which either rely on sophisticated techniques to survey the line, novel conductors and support structures, or novel agreements with customers to shed load or generation from the line when required. One particular technique, Real-time Thermal Rating (RTTR) of overhead lines, can only be applied in connection with Active Network Management which will also be discussed later in the document and which is being explored in our Flexible Plug and Play (FPP) Low Carbon Network Fund Tier 2 project.

We have applied Dynamic Rating of System Transformers across our investment plans for the three licence areas. This may or may not be associated with Demand Side Response in the same location. Note that we have concentrated on the primary and grid transformers ('system transformers') with greatest responsibility for delivering capacity and with the greatest thermal inertia due to their size. As shown earlier in the table, we consider that Dynamic Rating of secondary transformers may also play a role in managing thermal constraints at LV, but differently to system transformers, only as part of a range of options available and possibly only when associated with network re-configuration as well.

Partial Discharge testing is a common diagnostic and is taken at regular intervals during substation inspections and as one of a number of safety checks that may be carried out before entering a substation. We will discuss below how we expect to reduce some costs associated with replacement of switchgear by remotely monitoring partial discharge and being able to analyse trends in discharge activity.

We will discuss below both our review of Fault Current Limiters as a means of releasing capacity for general load growth as well as to enable new generation connections. At this stage, we see more promise for this second application.

Finally, the usage of Active Network Management is not just limited to Real Time Thermal Rating of overhead lines – it is a necessary enabling technology which can be used to dispatch increased capacity from real-time ratings of a number of different classes of assets, or from Demand-Side or Generation-Side Response.

Each of the following sections discusses in turn:

- how scenario modelling was used to identify the opportunity to deploy the Smart Grid technique (the 'Need case')
- a summary of the costs which the Smart Grid technique helps to defray (the 'Cost-benefit summary')
- how the scenario modelling was validated by other sources of information ('Data assurance')
- how the benefit for current and future customers was analysed and the result ('Cost-benefit analysis')

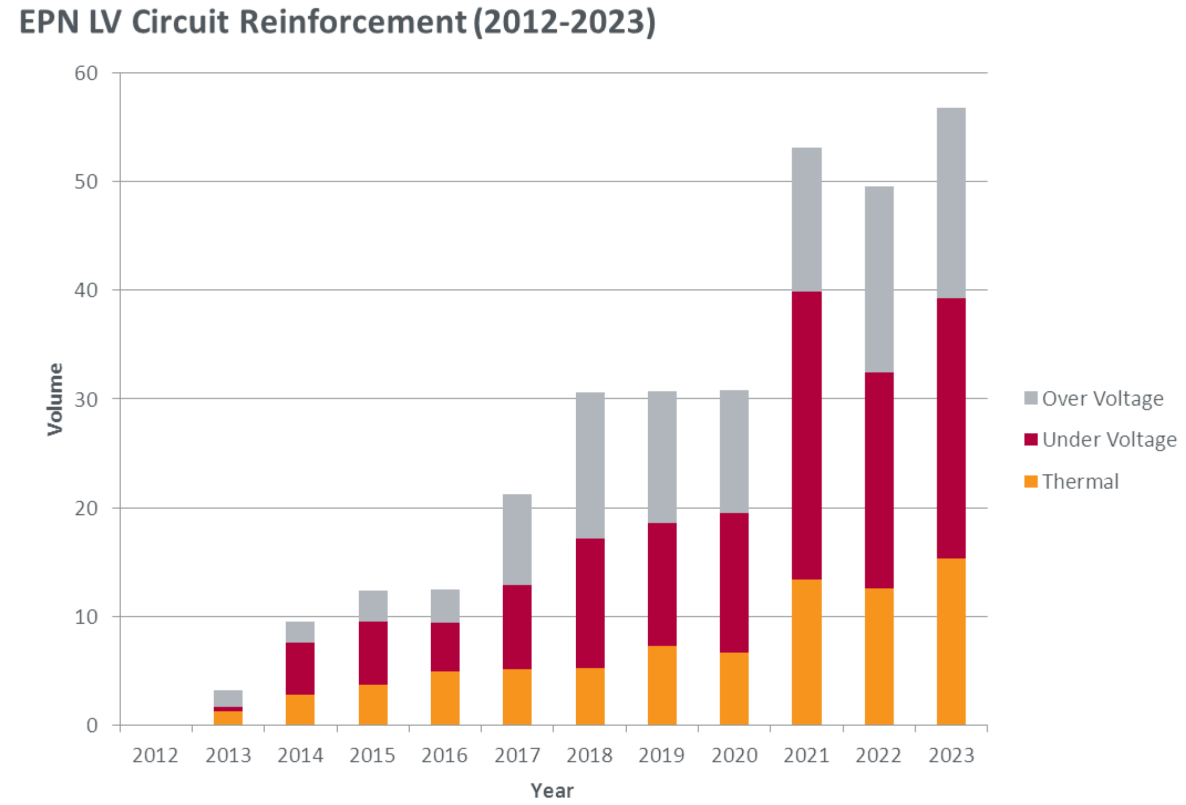
5.3 Savings in LV reinforcement compared to forecast volumes

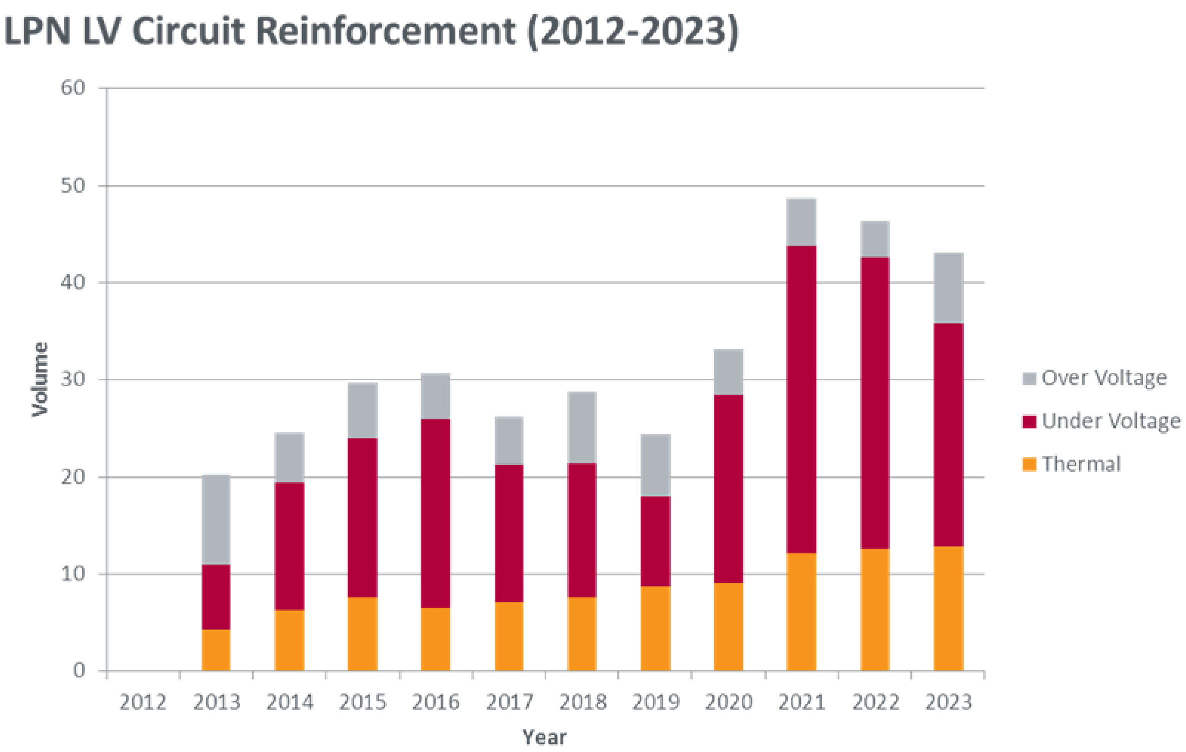
5.3.1 Need case

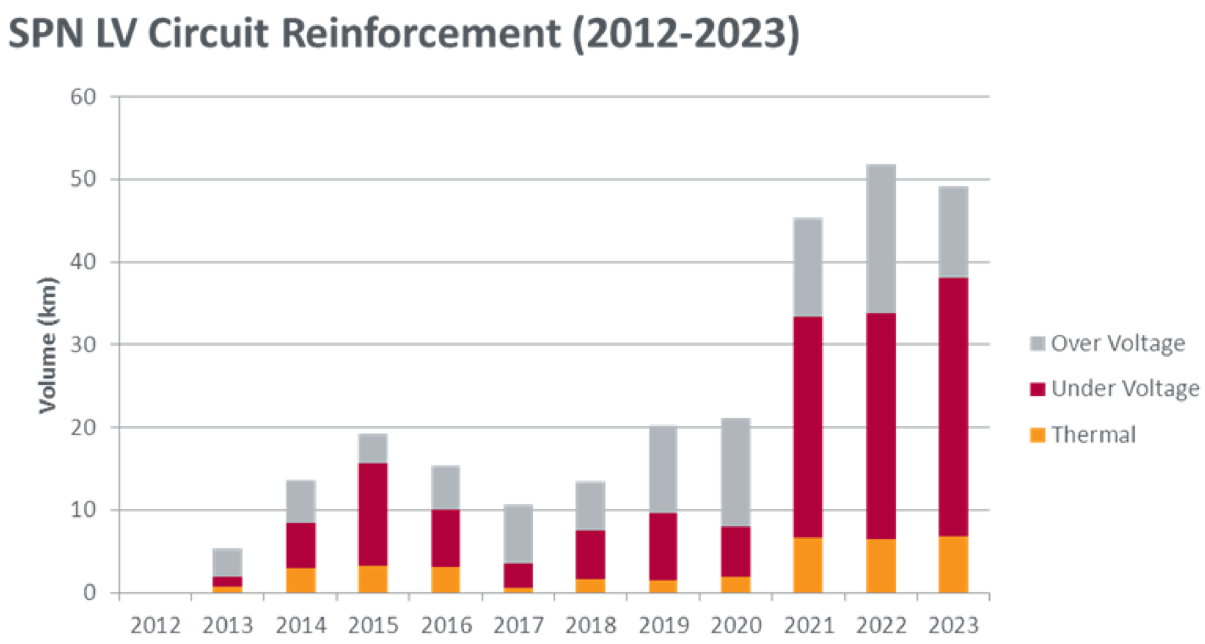
The connection of Low Carbon Technologies to distribution networks is expected to have a dramatic effect on the need to reinforce LV networks when compared to historic trends. Many of the technologies such as Electric Vehicles (EVs), Heat Pumps (HPs) and domestic solar Photovoltaics (PV) are expected to be connected to existing LV networks which have not traditionally been designed to cater for such demands. This presents an opportunity for smart technologies to solve the network issues that arise from LCTs to avoid the large expenditure that would be necessary if using traditional reinforcement techniques which may also prove disruptive to the public.

The fact that uptake of such technologies has not been encountered on this scale before and the volume of LV networks makes site-by-site analysis impractical for such situations. For this reason modelling has been used both to assess the need for reinforcement and also to analyse where smart solutions can be used to avoid the need for traditional reinforcement. We have used two models for this purpose, the Load-Related Expenditure (LRE) model developed for UK Power Networks by Imperial College, and the Transform model.

The graphs below show the Imperial Load-Related Expenditure (LRE) model's outputs regarding the volume of LV circuit reinforcement (in circuit-km per year) broken down by investment driver: thermal, over voltage and under voltage. The corresponding levels of investment are shown in the table in the next section.







These profiles bear a strong correspondence to our experience, but at a much higher volume. Only in the most extreme circumstances have we, to date, seen our LV circuits reach their thermal limits, and as such are expecting voltage management to be the larger issue. We can cite a specific example in which as a result of a gas outage, another utility deployed electric heaters to our customers in a concentrated geographic area and without the opportunity to co-ordinate our guidance to customers. This example of a small region instantly going ‘all electric’ for their heating needs and without any inherent diversity did indeed push the thermal capacity of our low voltage circuits. However, these circumstances to date have been the exception. On this basis, we have based our business plan assumptions on the profile shown in these diagrams.

We are aware, however, that the Transform model is forecasting significantly higher expenditure in our EPN and SPN licence areas on reinforcement of LV feeders and on a comparable ‘business-as-usual’ or conventional reinforcement approach. In our LPN licence area, the Transform model forecasts a lower spend, but we feel that a potential contributor to this is the unit costs associated with LV feeder reinforcement in London, which we have not factored into the Transform model but which are factored into the Imperial LRE model.

In summary, both models indicate a significant increase in instances requiring LV feeders to be reinforced as a result of the uptake in LCTs, and in response to both thermal and voltage constraints, unless Smart Grid alternatives can be found, and far in excess of our historical experience.

5.3.2 Cost-benefit summary

We have taken a hybrid approach in this particular case of using a point chosen between the Imperial LRE and Transform model predictions in order to predict the volume and cost of conventional reinforcement that would be required. We are deliberate in not choosing the higher of the two models’ predictions; and we are deliberate in not updating the Transform model’s view of unit costs in our LPN licence area, instead continuing to use the GB benchmark unit costs as shipped in the model. Both of these measures ensure that we are setting a fair starting point and in our customers’ favour.

However, we recognise that the two models are showing different recommendations, and in some areas differ by significant amounts. In EPN, where the variance is greatest, we take the 27.5% percentile point between the two models’ outputs; and in LPN and SPN respectively where the variance is smaller, we take the 80% and 90% percentile between the two model’s outputs.

When applied to the total reinforcement forecast, choosing a percentile of 27 between the two models’ outputs for our EPN licence area restores the logical order between the DECC scenarios. DECC scenario 4 has the lowest reinforcement requirements, through to DECC scenario 3 which has the highest reinforcement requirements due to the highest level of electrification.

Whilst the hybrid approach was only ever applied to the Low Voltage reinforecement estimate, it is re-assuring to observe and validate its effect at the level of the whole reinforcement forecast.

Applying values of significantly greater than 27% do not correct the ordering between the DECC scenarios. Applying values significantly less than this may not provide a sufficient allowance for reinforcement, given that one model is predicting a greater level of reinforcement is required than the other.

Having applied a percentile of 27% to EPN, the percentiles of 80% in LPN and 90% in SPN maintain a relationship between predicted reinforcement in each of EPN, LPN, and SPN which matches the Transform model for DECC scenario 3. This ensures that in the most onerous scenario, our funding forecasts are in line with the Transform model.

We considered an alternative approach in which a simple mid-point was used between the two models, i.e. the 50th percentile, resulting in a different allowance. The same level of Smart Grid savings was offered in this case, but is split differently across our three licence areas EPN, LPN and SPN.

As such, the two approaches offer the same Smart Grid savings; both benefit from having two "views of the world" and take the best of each; but both protect customers by not simply taking the larger of the two models' forecasts.

We have than applied approximately a 25% stretch challenge to the total across each of our licence areas, committing ourselves to use Smart Grid solutions to defray approximately 25% or more of the overall costs which would otherwise be associated with conventional reinforcement of LV feeders. This is summarised in the table below. The savings have increased marginally from our June 2013 submission, as a result of minor redistributions of LV reinforcement costs across our licence areas.

Item	EPN	LPN	SPN	All DNO's
Costs of conventional reinforcement forecast by the LRE model	£25.1m[1]	£41.9m[2]	£21.3m[3]	£88.3m
Costs of conventional reinforcement forecast by the Transform model[4]	£102.6m	£23.3m	£51.1m	£177.1m
Variance between model estimates	£77.5	£18.6	£29.8	
Percentile chosen	27% / £46.2m	80%/ £38.4m	90%/ £48.0m	£132.6m
Allowance for LV reinforcement built into our business plan	£34.4m	£28.5m	£34.6m	£97.4m
Net saving to be delivered by Smart	-£11.8m	-£9.9m	-£13.4m	-£35.2m

5.3.3 Data assurance

We explained in Section 4.2 that these interventions are dedicated to the secondary network and are based on forecast volumes of needed interventions, and are not allocated to specific sites. In practice, within the RIIO-ED1 price control period they will be adopted on a site-by-site basis as the need arises, taking into account circumstances pertinent to each site and the most cost-effective solutions available.

We have some confidence that the models, which are based on generic but statistically correct models of our LV networks, necessarily miss an aspect of engineering insight which our planning engineers are able to apply when planning individual schemes. As such, we would expect that in some cases the conventional reinforcement can be avoided through re-configuration of the existing assets. Nevertheless, we have carried out additional analysis to assure ourselves that the 25% stretch saving is achievable.

[1] Output from LRE model on 27/3/2013, and corresponds to 241km of LV cable reinforcement.

[2] Output from LRE model on 21/3/2013, and corresponds to 268km of LV cable reinforcement

[3] Output from LRE model on 15/3/2013, and corresponds to 196km of LV cable reinforcement

[4] Output from Transform model in Business-As-Usual mode, expenditure on LV circuits

The table below shows the results of testing our assumption that we can deliver the 25% stretch saving in our LPN licence area. Each row (labelled ‘5%’, ‘10%’, etc.) represents an increasing proportion of instances in which a Smart Grid solution is used to avoid conventional reinforcement of LV feeders. At the extreme case, labelled ‘100%’, no conventional reinforcement takes place.

Each column (labelled ‘5’, ‘10’, ‘20’ etc.) represents the cost of the conventional reinforcement scheme which the Smart Grid solution is trying to displace. At the extremes, very low cost conventional reinforcement schemes costing only £5k are very difficult to displace with a cheaper Smart Grid alternative.

Each cell in the matrix then provides the maximum cost which the Smart Grid solution can have in order to deliver the 25% overall saving, if competing with the conventional reinforcement cost in that column and if rolled out in the proportion determined by that row. In cases where the entry in a cell is zero, it implies that the stretch cannot be met, since the Smart Grid alternative would have to be a zero cost alternative and still would not meet our overall stretch target.

Cost of Smart required to meet the stretch (UCI_{smart})

This is the CapEx budget available to spend on the alternative.

Unit cost of replacing between 1/4 and 1/3 of a substation's LV feeder network

% of interventions replaced with the Smart Grid intervention ($\%_{smart}$)	Unit cost of conventional ($UCI_{conventional}$) (£k)										
	5	10	20	30	40	50	60	70	80	90	100
5%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
20%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
30%	0.7	1.4	2.8	4.2	5.5	6.9	8.3	9.7	11.1	12.5	13.9
40%	1.8	3.5	7.1	10.6	14.2	17.7	21.2	24.8	28.3	31.9	35.4
50%	2.4	4.8	9.7	14.5	19.3	24.2	29.0	33.8	38.7	43.5	48.3
60%	2.8	5.7	11.4	17.1	22.8	28.5	34.2	39.9	45.5	51.2	56.9
70%	3.2	6.3	12.6	18.9	25.2	31.5	37.8	44.2	50.5	56.8	63.1
80%	3.4	6.8	13.5	20.3	27.1	33.8	40.6	47.4	54.2	60.9	67.7
90%	3.6	7.1	14.3	21.4	28.5	35.6	42.8	49.9	57.0	64.2	71.3
100%	3.7	7.4	14.8	22.2	29.7	37.1	44.5	51.9	59.3	66.7	74.2

The reason for testing our assumptions in this way is that there is a minimum amount of money that needs to be spent on any solution to a network need, whether a Smart Grid solution or a conventional solution. Mobilising staff to work on the network, getting them to site, the time taken to arrange outages, etc. is non-negligible. If this test had demonstrated that we needed to be rolling out many Smart Grid solutions at LV, such as voltage regulators, on-line tap changers, enhanced AVC schemes within budgets of £10-20k per site, then these mobilisation activities are not negligible. Fortunately, in the areas most of interest, in which we are trying to avoid having to replace several hundred metres of LV feeder, representing a significant fraction of a substations' feeder network, then Smart Grid solutions can be costed between £20k - £50k and still meet our overall stretch target.

5.3.4 Cost-benefit analysis

The Transform model was used to allocate the savings across solutions based on their relative cost-benefits. At this stage, we are most confident in the solutions listed in Table 5 as the means by which to meet this saving, and which are all network-side techniques. This does not cover the full range of solutions available and used in the Transform model. Specifically, we note that all of local EV charging control, micro-generation (PVs) providing power factor correction or being constrained off, embedded DC networks and LV connected storage will require some aspect of standardisation or interaction with the meter-side. As such, these solutions will take longer to come to the market. Finally, we do not feel that dynamic rating of LV cables is a viable solution.

5.4 Demand-Side response (DSR)

5.4.1 Need case

Demand Side Response (DSR) can be delivered either from a reduction in demand from demand customers, or by generators generating for a contracted period. It can address occasional shortfalls in capacity on the network and thereby avoid reinforcement. This is demonstrated in the diagrams on the next page, which show the maximum capacity shortfalls (in MVA) on our three licensed networks based on winter 2011/12 data and forecast forward to 2014/15. The histograms make clear that the majority of shortfalls are smaller rather than larger, and give an indication of the size of DSR capability that is useful: specifically, around 5MVA in LPN would cover most instances of shortfalls and in EPN and SPN slightly less. Note that these shortfalls could be associated with transformers or circuits, and could be relevant in the event of either a first or second circuit outage.

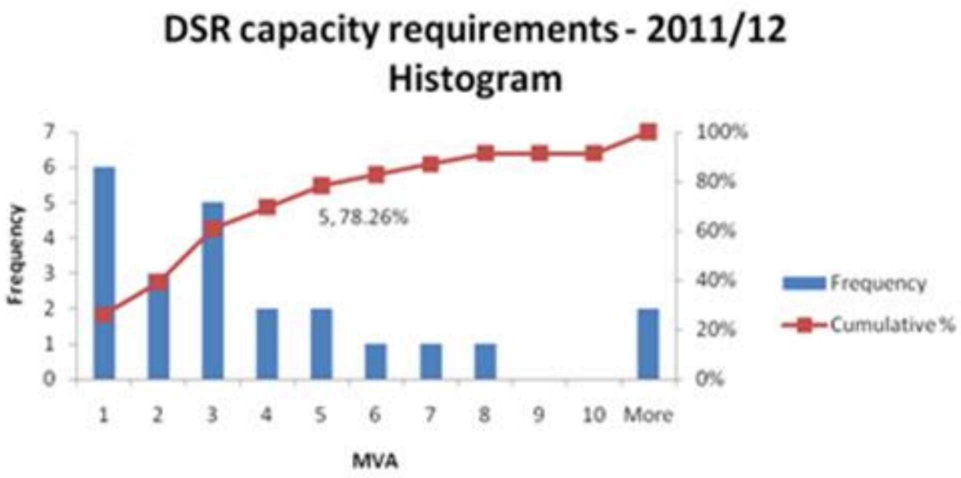
Whilst this addresses the capacity shortfall, or the shortfall in the rating of substations and circuits, we also need to assess the period for which this lasts. A manual 'hours at risk' analysis has been carried out for all LPN sites with a Load Index (LI) of 4 or 5, the highest levels of utilisation. The average 'hours at risk' for these sites in winter 2011/12 data was 6 hours. Therefore we assume 6 hrs to be the availability period during which DSR for LPN must be able to deliver.

The required duration for EPN and SPN has been estimated to the nearest half-hour by pro-rating the figures for LPN, for example:

- EPN DSR duration = 6 hours (LPN DSR duration) x 2MVA (EPN DSR capacity) / 5MVA (LPN DSR capacity) = 2.5 hours.

Similarly the SPN DSR duration was estimated to be 3.5 hours.

Figure 11 LPN: Y = 5 MVA



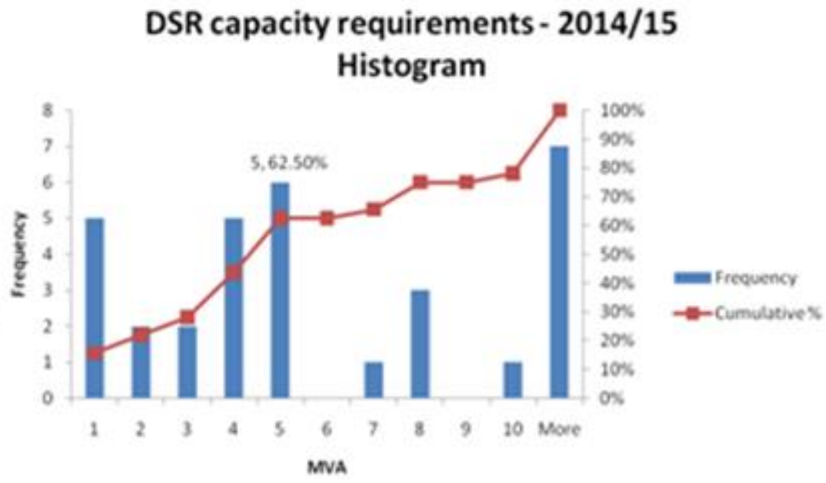
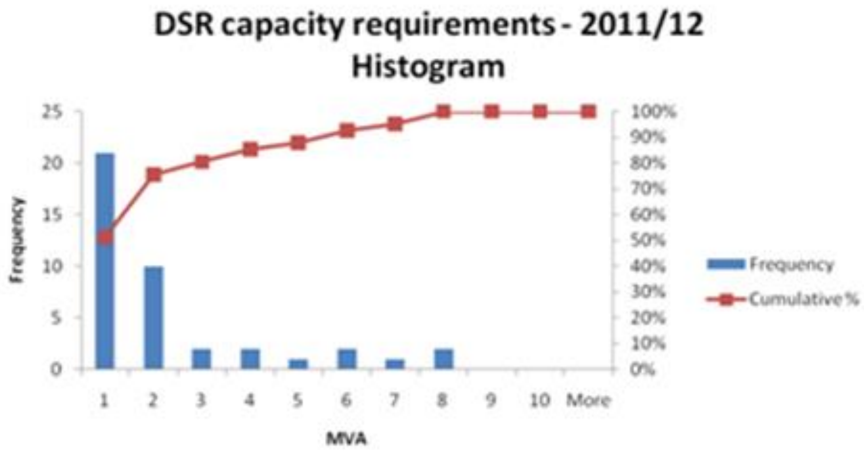


Figure 12 EPN: Y = 2 MVA



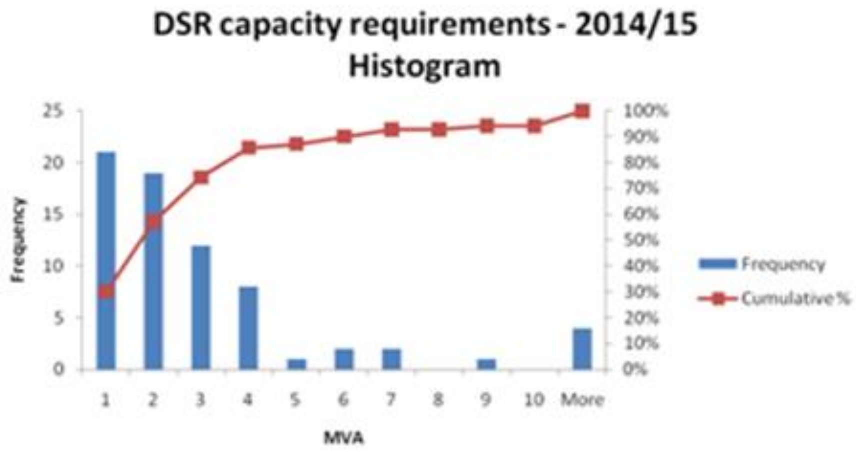
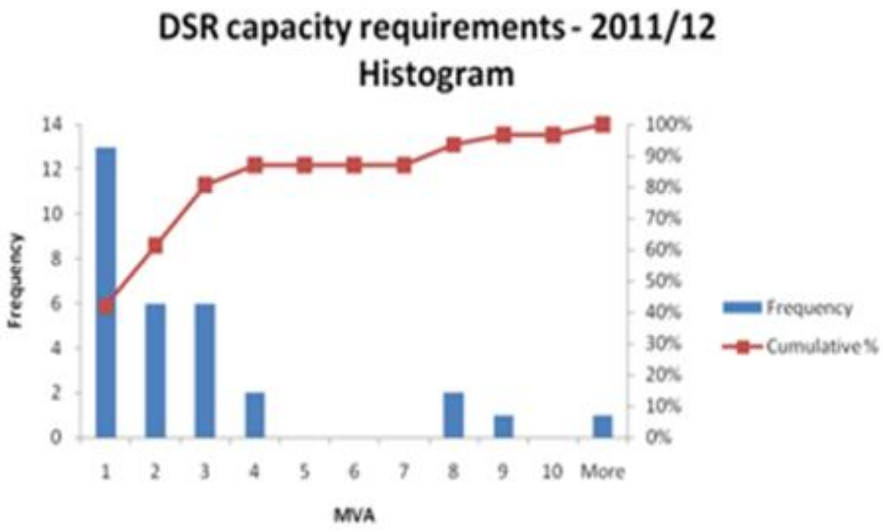
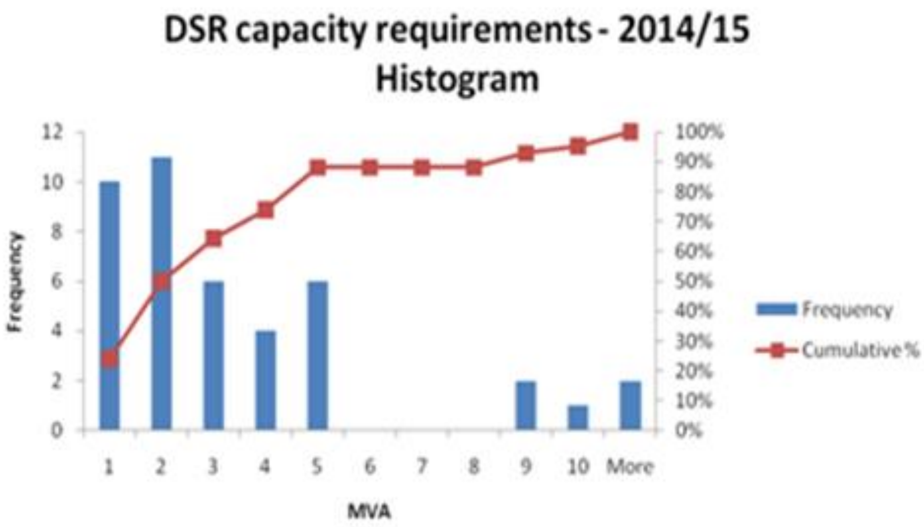


Figure 13 SPN: Y = 3MVA





5.4.2 Cost-benefit summary

Demand Side Response (DSR) is conventionally seen as an option to defer reinforcement from one regulatory period to another. UK Power Networks has taken a wider approach, as shown by the summary table below, which summarises the number of reinforcement schemes which include DSR, and the resulting saving to customers.

We have reviewed our conventional load related investment plan since the June submission, with the result that the majority of DSR schemes are as stated in June. One LPN scheme (Woodgrange Park) and one EPN scheme (Warners End) have been re-reviewed and no longer deemed appropriate for DSR, but others have been added in the EPN area.

	EPN		LPN		SPN	
Approach	**(No. of)**	**(£m)**	**(No. of)**	**(£m)**	**(No. of)**	**(£m)**
Defer substation upgrades(1)	5	6.7	1	5.7	2	3.4
Defer new-build substations(2)	2	5.2	1	9.5	3	14.4
Manage transfer capacity lost during construction(3)			1	-0.1		
Manage construction interdependencies to avoid derogations(4)			5	-1.1		
Defend against economic growth					5	N/A
Total	7	11.8	8	13.9	5	17.7

(1) EPN: Whittlesey, Eye, BEE (Commercial and Wembley Stadium), Orton, Caister; SPN: Queen's Park, Sheerness; LPN: Southbank
(2) EPN: Brandon, Kempstone; SPN: Saxon Road, St Andrews Road, Tadworth; LPN: Whiston Rd
(3) LPN: Moscow Road
(4) LPN: St Pancras, Wimbledon Grid, Wandsworth Grid, Eltham Grid, Hyde Park

Defer substation upgrades and new-build substations

DSR will be used to either defer the upgrades of substations or the construction of new substations where an upgrade is not possible. This is the more traditional concept of how DSR is applied and the majority of the potential sites selected in this business plan. An example of where applying DSR to a site can defer reinforcement is at Whiston Road in our LPN licence area. The Whiston Road 11 kV substation needs to be upgraded to accommodate the load growth in the area. Unfortunately there is not enough space at the substation for the upgrade to take place and therefore new substation will need to be built and the load transferred; the new substation is proposed to be built in Hoxton nearby.

DSR has been investigated at this site and it has been realised by applying DSR will enable UK Power Networks to defer the build of a new proposed Hoxton substation out of RIIO ED1 and help manage the network constraint at Whiston Road 11 kV substation. Contracting 5 MVA DSR between 2021 and 2025 (inclusive) for £300k (£150k of which ED1) will defer the new Hoxton substation new build cost of £19.9 million to £10.3 million in ED1, therefore saving a total of £9.5 million.

Manage transfer capacity lost during construction or construction interdependencies

DSR will be used to manage both the loss of network capacity to the network during load transfers for both distribution and grid supply points. The construction of new substations or upgrades often means that load has to be transferred on to other areas of the network whilst the work is being completed and can therefore put them at risk of being non-compliant. DSR will be used to mitigate derogation. UK Power Networks has already displayed examples of this at Ebury Bridge through the Low Carbon London programme where DSR services have been contracted to mitigate derogation. Note that in the summary table of savings, these appear as negative, since they are additional costs rather than savings.

Defend against uncertainty of economic growth

As discussed previously, our core scenario for load growth is consistent with the long-run average of household growth, and a reasonable uptake of Low Carbon Technologies (LCTs). If either of these grows more aggressively, then Demand Side Response may act as a first line of defence and avoid additional reinforcement.

5.4.3 Data assurance

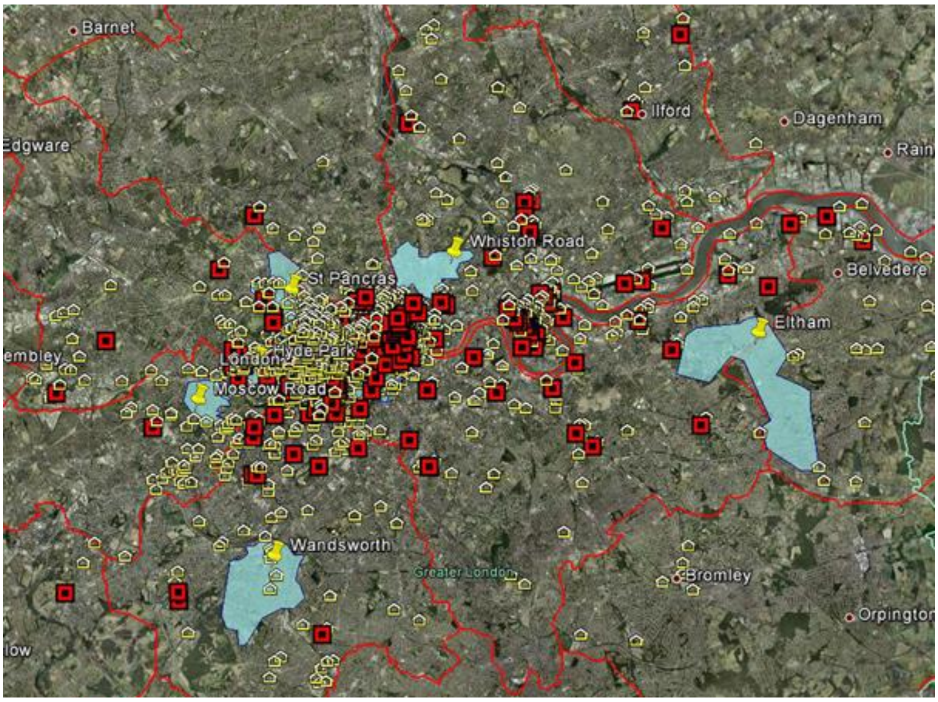
UK Power Networks' decision to incorporate DSR in our business plan has come from the work that has already been carried out in the industry to date. There have been a number of Low Carbon Network Fund (LCNF) projects carried out by DNOs that have looked at DSR and UK Power Networks' Low Carbon London project has been one of them. Experiences from Low Carbon London have shown that developing a DSR programme and then recruiting for it needs to be taken with a cautious approach. We should not imagine that all capacity shortfalls shown in Section 5.4.1 can be met through DSR. The relationship gained with the Low Carbon London aggregator partners have given us a breadth of knowledge and this has helped with regards to what is achievable.

One commercial aggregator has shared an estimate with UK Power Networks that it might be possible to obtain 2-5% of building demand as DSR and 10-20% of non-intermittent generation as DSR. These are broad assumptions and as such we need to be aware that:

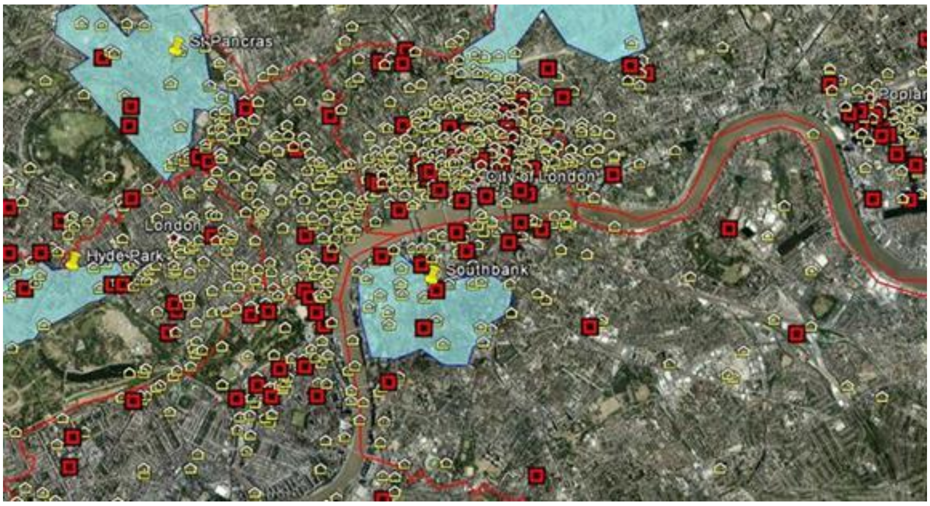
- A substation may serve largely domestic customers. There is very little active domestic DSR in the UK at present, but we expect the advent of Smart Meters to greatly increase this resource
- Another substation might supply a number of datacentres. In this case, the DSR potential there probably pushes 80% of the datacentre load, but it is largely diesel, and it may face permit-to-sync constraints or fault level issues
- Sources of Industrial & Commercial DSR may have a number of different underlying technologies, such as a hospital (CHP and diesel), a community heating scheme (CHP), cold storage (load reduction) etc. As such, the scale and duration of a response differs from one I&C customer to the next
- Building demand is typically not as accessible as their generator counterparts. The most obvious example is that of load management of cooling systems in office buildings or retail parks. This may, however, be limited to sites with thermal storage

We have carried out a level of data assurance by analysing our customer database whilst bearing in mid the estimates provided by the commercial aggregator for DSR potential. The figure below shows a section of UK Power Networks' LPN licence area.

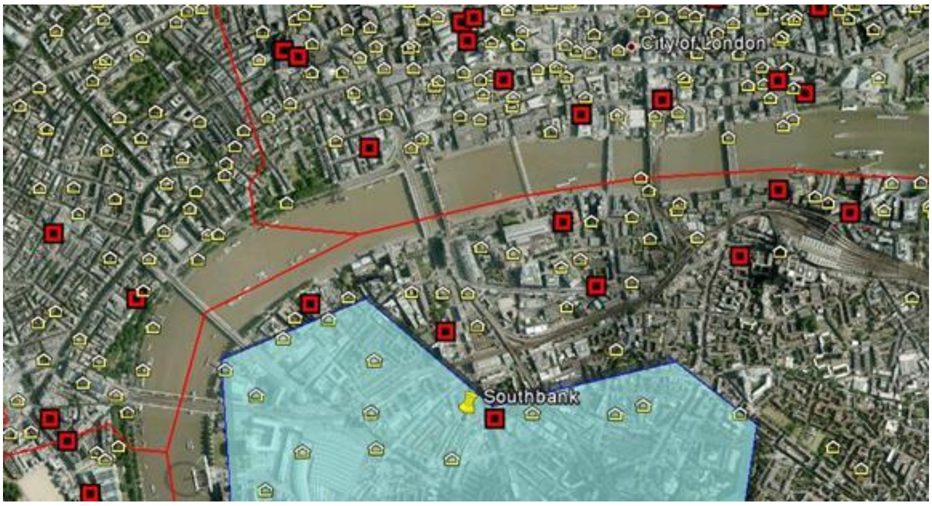
The red squares represent sites with non-intermittent generation capacity of 500 kW and above. The yellow houses indicate the industrial and commercial sites that have recorded a maximum demand of 500 kW or more. The blue shaded areas represent the catchment area of substations that have been identified for DSR. A value of 500 kW has been chosen as a value as it is believed that these sites would be able to provide DSR services. It is not the case that smaller aggregated sites will not be able to provide a sufficient DSR services but for the purposes of this document the focus will be on the indicated sites.



Two close-ups are shown in further detail below:



Larger buildings with the potential to offer DSR services are concentrated around the central London area, this is similar for the generation sites but they are more opportunities further out of central London.



It should be clear from the maps shown above that UK Power Networks is taking a reasonably aggressive stance with respect to DSR, in the interests of saving customers' money. In some cases there is a very obvious pool of generation and large I&C customers drawing on a substation, and in other cases the load and generation is much more disaggregated across smaller customers.

All three of UK Power Networks licence areas come with their own unique network opportunities for DSR. The EPN licence area has far more generation sites spread across the region as the fault level constraints that are found in the LPN licence area are not present. The generation sites are not constrained to one location and therefore the opportunities for DSR can be viewed as promising regardless of location. The SPN licence area has, like the LPN licence area, pockets of generation and large industrial and commercial sites centred on towns and cities. In most cases DSR is applied to areas with large associated demand and therefore opportunities for recruitment of DSR services should be fairly moderate. Appendix B has similar maps as above for the whole of the EPN and SPN region, colour coded according to the quantity of generation and demand customers above 500kW.

5.4.4 Costs and cost-benefit

In their role as the GB System Operator, National Grid contract balancing services and which acts as the main market for standby generators and responsive demand. The balancing services which National Grid contracts for are Firm Frequency Response, Fast Reserve, Frequency Control by Demand Management and Short Term Operating Reserve (STOR); these services are used to resolve different issues in balancing supply and demand. It is STOR that is the more widely participated in by customer sites with generation or other types of flexible demand, these sites often managed by aggregators, as the financial rewards for participation can be quite lucrative.

National Grid STOR programme splits the year into 6 seasons (normally 2 months in length); April through to March inclusive. They contract for demand all year round for the morning and evening peak normally covering two time windows, morning to early afternoon and late afternoon through the evening. Sites that participate in STOR can either be on a committed or flexible contract for any of the seasons. Participating sites on committed contracts must be available for all windows in the season they have opted into. Flexible contracted sites have the ability to notify a week ahead of their availability to participate; these sites are not favoured by National Grid.

UK Power Networks will be competing with National Grid for these sites for their service, which will be challenging as they will be competing against a well-established market that has been around for a long period. Sites are able to forecast the income they will receive by participating in STOR and therefore may be reluctant to participate in a new and untried DSR programme. **At the time UK Power Networks really started to investigate the viability of DSR for managing network constraints the average price being paid by National Grid for STOR was £7.50 per MW per hour for availability and £200 per MW per hour for utilisation.** We believe the market will recover to these levels as more intermittent generation appears on the system and increases the need for balancing services.

UK Power Networks understands that in order for them to acquire sites to participate in its DSR programme the price that is paid will need to be greater than that being paid by National Grid for STOR. The earning for participating in UK Power Networks' DSR programme would have to cover the cost of sites pulling out of STOR for the required periods. UK Power Networks have summer and winter peaking substations where most network constraints occur over a three to four month period. This could potentially mean that committed contracted sites will need to either pull out of one or two seasons to participate in UK Power Networks' DSR programme depending on the time of the year. With this in mind **UK Power Networks has used a planning assumption that a price of £30 per MW per hour for availability and £200 per MW per hour for utilisation would be sufficient to procure these services**. This chosen cost will cover the cost of a committed customer opting out of STOR and more, which will be the main driver for their participation.

The cost-benefit calculation has been performed using Ofgem's Cost-Benefit Analysis format. The investment strategy is to target capital reinforcement of the order of £3 million in EPN and SPN, or £5 million in LPN. This typically means substation upgrades rather than load transfer schemes, but the use of DSR to compensate for load transfer capacity which is temporarily lost during construction is invaluable. Similarly, we would seek to first apply Real-Time Thermal Rating on system transformers and which has a slightly higher NPV, before we applied DSR to the site containing those transformers.

Table 6 Solution: Demand Side Response for LPN licence area

Item	Value	
Policy assumptions for applying the solution	Investment Strategy	Defer £5m by 4 years
	Engineering application	London substations with either circuit or substation constraint which is seasonal (3 month availability period).
Financial assumptions for applying solution	DSR availability: £30/MWh DSR utilisation: £200/MWh Daily availability window: 8 hours Duration of response if called off: 6 hours	
Weighted cost of capital (WACC)	4.1%	
Discount rate	3.5%	
NPV (at years)	16 years	£0.49m
	24 years	£0.40m
	32 years	£0.32m
	45 years	£0.24m
Additional benefits not yet quantified	N/A	
Assessment result	Introduces flexibility and optionality	

Table 7 Solution: Demand Side Response for EPN licence areas

Item	Value	
Policy assumptions for applying the solution	Investment Strategy	Defer £3m by 3 years
	Engineering application	Substations with either circuit or substation constraint which is seasonal (3 month availability period).
Financial assumptions for applying solution	DSR availability: £30/MWh DSR utilisation: £200/MWh Daily availability window: 5 hours Duration of response if called off: 2.5 hours	
Weighted cost of capital (WACC)	4.1%	
Discount rate	3.5%	
NPV (at years)	16 years	£0.29m
	24 years	£0.26m
	32 years	£0.23m
	45 years	£0.18m
Additional benefits not yet quantified	N/A	
Assessment result	Introduces flexibility and optionality	

5.5 Overhead lines

5.5.1 Need case

There are 13 OHL routes that are reaching their maximum utilisation during the ED1 period where direct reinforcement is proposed; there are others where more complex solutions are proposed. This is a slight decrease from the number of schemes discussed in our June submission, but continues to represent a significant capital expenditure. Particularly over a period where load growth, as predicted by our models, is relatively low, this provides the opportunity for a solution giving a relatively small increase in capacity headroom to be effective for a significant period of time.

UK Power Networks has been involved in several innovation projects relating to Overhead Lines (OHLs) over DPCR4 and DPCR5. Many of these have come through the Strategic Technology Programme (STP) with other UK DNOs but some have been carried out internally. In order to deliver most benefit from this work a project was put in place to look at the best value solutions to solve OHL capacity constraints based on what is currently known or solutions that are now available.

In determining which techniques to implement, two suggestions were raised and rejected, specifically the concepts of different Daytime and Night-time ratings; and ratings over four seasons rather than the current regime of only three seasons. Daytime/Night-time ratings were shown to deliver no significant capacity increase. The revised four season ratings would lead to an improvement for summer constrained circuits but a detriment for winter constrained circuits. Work is on-going through the STP to confirm these findings and update ENA documents ACE104 and P27.

We have chosen as the first stage to maximise the static rating of the overhead line by allowing an increase in the operating temperature of the line. Some data assurance is required for this which is discussed below, and significantly this data assurance is being achieved through highly accurate survey data gathered by helicopter. This identifies the maximum utilisation of the line given no additional work or minor remedial works.

In addition to this, and in agreement with local demand or generation which is willing to be curtailed if necessary, Real-time Thermal Ratings can then be applied using a weather station based solution. Trials have shown that RTTR is also a useful approach to enable quicker and cheaper new generation connections. Studies have shown that on average 30%[5] more generation can be connected than using static seasonal ratings where there is a correlation between generation output and wind speed – for example with wind generation . This approach, along with the associated commercial arrangements for interruptible contracts, is being developed through our Flexible Plug and Play Networks LCNF Tier 2 project.

A weather station based solutions is our preferred option because it provides an acceptable level of risk for minimal cost. Ratings are based on statistical analysis and risk assessment; absolute confirmation of operation within rating is not required. Early implementations may require additional thermal or sag/tension monitoring to provide confidence that the standard DLR equations are implemented correctly in our systems.

If neither of the above approaches would provide sufficient additional capacity, or there are compounding condition problems with the OHL assets, another approach must be used. Each will be assessed on a case by case basis as to which of the following options provides the best value:

[5] TDP/CN05 2007 IFI – Dynamic Line Rating for protection of Skegness – Boston Line, Central Networks, Power Technology, January 2008

- New conductor installed on the existing supports (including traditional, large size or High Temperature Low Sag (HTLS) conductors)
- New conductor installed on new supports (re-build the line)
- Add an additional circuit or other network re-configuration

5.5.2 Cost-benefit summary

The table below shows the total cost of the EHV (33kV-132kV) circuit reinforcement in UK Power Networks Network Asset Management Plan for the ED1 period. This covers both Overhead Lines and underground cables. It includes the savings included by implementing smart solutions and the implementation costs of those solutions, and demonstrates a saving of around 5% over and above the efficiency savings we are committing to elsewhere in the business plan in the cost of carrying out the work. This is a slight increase in the level of savings being delivered, since the same absolute level of savings is being delivered against a slightly smaller capital reinforcement plan than was submitted in June 2013.

Item[6]	EPN	LPN	SPN	all DNOs
Costs of conventional reinforcement	£66.4m	£60.7m	£38.9m	£166.0m
Savings from displaced reinforcement	-£10.6m	-	-	-£10.6m
Cost of implementing Smart Grid options	£2m	-	-	£2m
Total	£57.8m	£60.7m	£38.9m	£157.4m
Net saving	£8.6m	-	-	£8.6m

5.5.3 Data assurance

The key safety consideration in applying RTTR to an overhead lines is the clearance under the conductors (i.e. to prevent growing trees, buildings, vehicles or farm machinery, or an individual coming into contact with a low-hanging live conductor. When the operating temperature of a line is increased the conductor will sag further (reducing clearance). Ultimately the annealing temperature of the conductor will limit its rating irrespective of sag or ground clearance. In order to ensure safety is maintained it is vital to have good information about an overhead line and its surroundings to ensure that the ESQC Regulations are not breached and that the conductor is not likely to be damaged.

[6] Figures taken from NAMP Table J Baseline 4th February 2014

To that end we have commissioned a series of Light Detection and Ranging (LiDAR) surveys on the lines proposed for reinforcement to confirm the line profiles and sag under maximum operating conditions. These surveys provide more accurate assessments of clearance than ground-up measurements due to the ability to model the line loading in PLS-CADD.

Where there is any doubt over the age or condition of a conductor, a sample is sent to a test laboratory such as ERA Technology for assessment. This provides confidence in the ability of the conductor to run at an increased temperature with minimal increase in risk.

5.5.4 Costs and cost-benefit

The cost-benefit calculation has been performed using Ofgem's Cost-Benefit Analysis format, which has the following parameters:

Table 8 Solution: Static uprating using novel assessments

Item	Value	
Policy assumptions for applying the solution	Investment Strategy	Defer £6m for 8yrs
	Engineering application	33kV & 132kV OHLs reaching existing capacity constraints
Financial assumptions for applying solution	Scheme cost £6.36m Temp Uprating & remedial work £0.9m	
Weighted cost of capital (WACC)	4.1%	
Discount rate	3.5%	
NPV (at years)	16 years	£1.31m
	24 years	£1.06m
	32 years	£0.88m
	45 years	£0.67m
Additional benefits not yet quantified	N/A	
Assessment result	Introduces flexibility and optionality	

Table 9 Solution: RTTR – Overhead Lines

Item	Value	
Policy assumptions for applying the solution	Investment Strategy	Defer reinforcement by 3y+
	Engineering application	33kV & 132kV OHLs reaching capacity with generation / loads connected likely to provide response actions
Financial assumptions for applying solution	Scheme cost £2.7m RTTR cost £35k Deferment = 3yr	
Weighted cost of capital (WACC)	4.1%	
Discount rate	3.5%	
NPV (at years)	16 years	£0.26m
	24 years	£0.24m
	32 years	£0.22m
	45 years	£0.20m
Additional benefits not yet quantified	N/A	
Assessment result	Good potential for saving, little optionality	

5.6 Dynamic transformer ratings

5.6.1 Introduction

5.6.1.1 Applying Real-Time Dynamic Ratings

In cases where thermal modelling suggests that a given substation could be at risk under abnormal ambient conditions (as with the example considered here under summer loading conditions) there would be merit in monitoring dynamic rating in real time.

Having determined through thermal modelling, the dynamic rating of a transformer based on its daily load cycle under critical loading conditions (typically winter and/or summer weekdays) the application of real-time dynamic ratings would depend on a number of complementary tools and techniques, including:

- Real-time monitoring of winding temperature of transformers in service
- Real-time monitoring of transformer loadings
- Real-time monitoring of ambient temperature
- Real-time predictive loading based on the above two parameters (i.e. predicted loading based on predicted ambient temperature and cyclic loading history)
- Real-time modelling of predicted rate of temperature rise in the event of loss of one transformer
- Real-time modelling of quantum and rate of load reduction / transfer required to prevent a WT trip operation in the event of loss of one transformer (including assessment of any requirement for pre-fault load reduction / transfer)

Applying real-time dynamic ratings on this basis would give rise to greatly enhanced risk management of highly loaded transformers (i.e. transformers with LI5 indices and with relatively high ‘energy at risk’ assessments).

5.6.1.2 Strategic advantages of a dynamic rating approach

Predicting quantum and rate of demand growth is complex, relying as it does on a number of demand-influencing factors which are difficult to predict such as: economic activity; housing growth employment growth; growth in digital appliances; and impact of improved appliance efficiency ratings.

In the current uncertain economic climate, forward trends in these factors are unusually difficult to predict, especially in the context of business plans looking up to 10 years or more ahead (for example RIIO business plans). However, this is further exacerbated by uncertainties surrounding the impact of Government policy towards electrification of heat and transport, and decentralised generation. These uncertainties extend beyond simply predicting future maximum demands experienced by networks (which traditionally have determined the need for reinforcement using static, or even seasonal, plant and equipment ratings) but also to the future demand shapes and load factors that networks will experience. This uncertainty, in turn, gives rise to doubts as to whether existing cyclic ratings will remain valid.

It follows that there is now a relatively low degree of confidence in predicting if and when substations, and associated circuits, will exceed firm capacity, and hence if and when reinforcement will be necessary. Given typically lead times for effecting reinforcement of 132kV and 33kV substations and circuits, this leads to two characteristic risks:

- Premature (or even unnecessary) reinforcement leading to technically stranded capacity or
- Belated reinforcement leading to non-compliance with p2/6 (and hence licence non-compliance)

Under these circumstances, solutions which effectively buy time; which can be relatively quick to implement; and (for example in the case of DSR contracts) relatively easy to stand down if the need does not materialise - are inherently attractive.

It follows that the application of dynamic ratings to system transformers at selective sites would potentially lead to both investment efficiencies and greater assurance of P2/6 compliance, particularly if applied in conjunction with DSR contracts which could be called on in the event of unfavourable ambient temperature and loading conditions.

5.6.2 Cost-benefit summary

The table below shows the total cost of System Transformer (generally 132/33kV or 132/11kV but also including 66kV and 22kV variants) reinforcement in UK Power Networks' Network Asset Management Plan for the ED1 period. The table also shows both the ED1 savings arising from applying thermal modelling and real-time dynamic ratings, together with the implementation costs which are assessed as £70k per transformer.

These savings represent individual projects that were provisionally proposed for ED1 based on predicted increases in Load Indices over the ED1 period, but for which deferment by implementing RTTR has subsequently been shown to be feasible. This is also a slight increase in proportion of savings being delivered, since the same absolute level of savings is being delivered against a slightly smaller capital reinforcement plan than was submitted in June 2013.

Item	EPN	LPN	SPN	all DNOs
Costs of conventional reinforcement	£114.4m	£103.2m	£46.6m	£264.2m
Savings from displaced reinforcement	-£9.2m	-£4.2m	-£4.9m	-£18.3m
Cost of implementing Smart Grid options	£1.5m	£1.1m	£0.7m	£3.3m
Total	£106.8m	£100.1m	£42.3m	£249.2m
Net saving	£7.7m	£3.1m	£4.2m	£15.0m

5.6.3 Need case

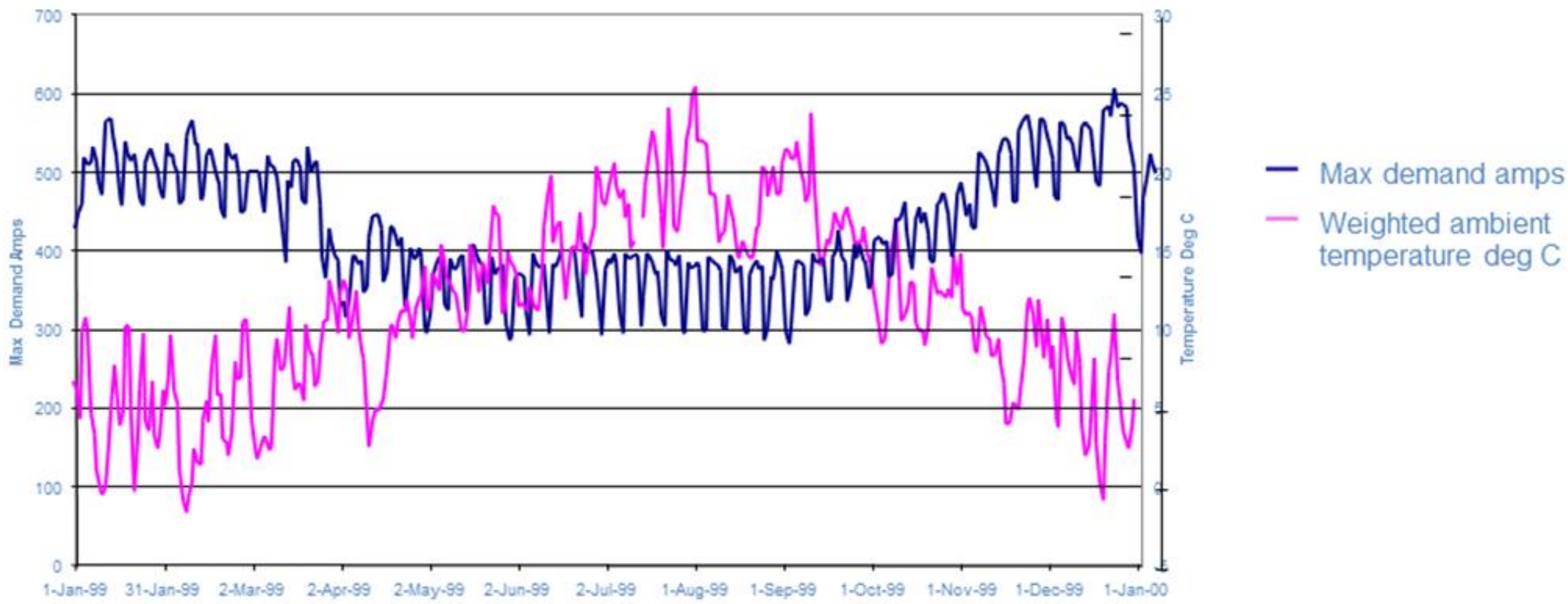
GB DNOs are required to design their networks in accordance with ER P2/6 'Security of Supply'. P2/6 sets levels of supply security classified in ranges of group demand. Supply security is defined in terms of the proportion of load that can, by design, be restored within a given time under a single outage event or a defined number of coincident circuit outage events.

ER P2/6 contains the following advice: 'For the first circuit outage, circuit capacity will normally be based on the cold weather ratings, but if the Group Demand is likely to occur outside the cold weather period, the ratings for the appropriate ambient conditions are to be used. Where the group demand does not decrease at the same rate as circuit capacity (e.g. with rising temperature) special consideration is needed.'

5.6.3.1 Security Assessments for Winter Peaking Demands

A typical load characteristic for a winter peaking substation is shown below. The chart illustrates a strong negative correlation between ambient temperature and demand – and hence a beneficial positive correlation between demand and seasonal transformer rating.

Figure 14 Typical load characteristic for a winter peaking substation

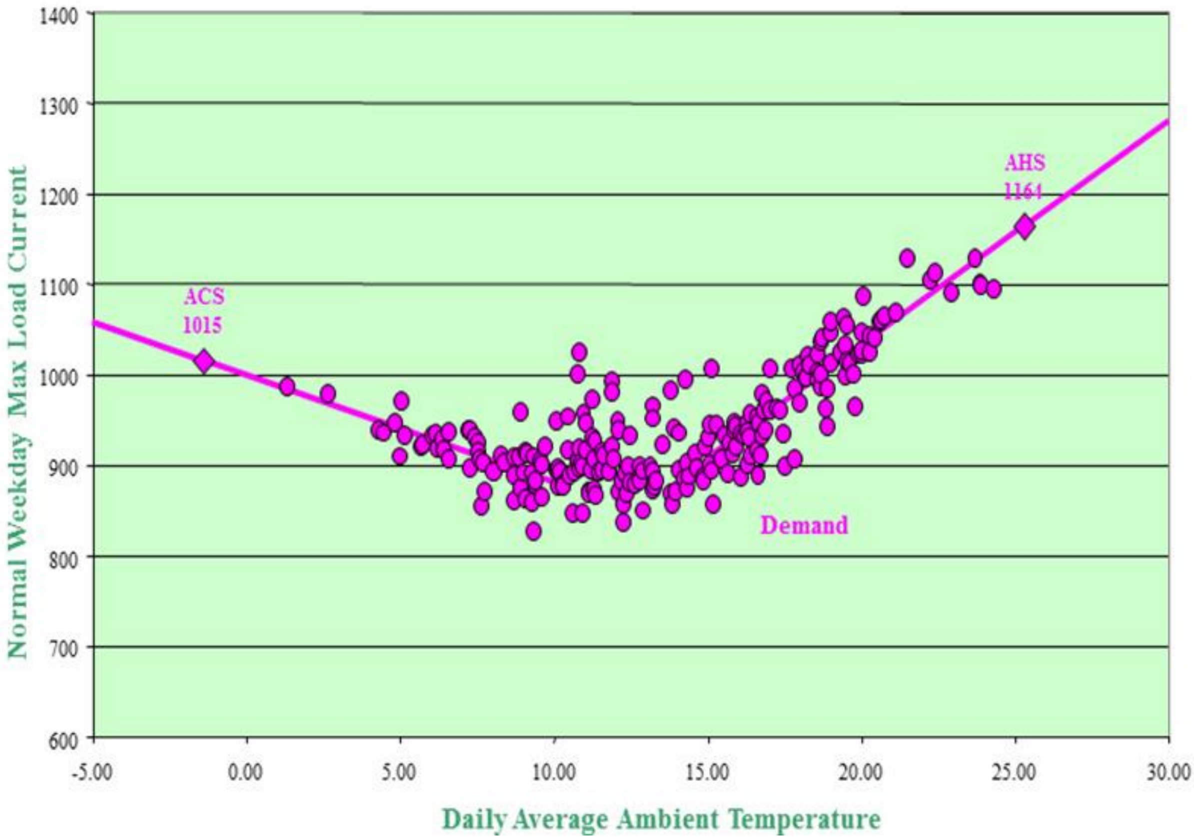


For traditional winter peaking substations it is rare to find a demand group that requires an assessment outside the cold weather period. Assessments would normally take account of years with abnormally high or low minimum temperatures, and then adjust the recorded demand in any year to a level that would occur in a year with average minimum temperatures; this is known as Average Cold Spell (ACS) correction.

5.6.3.2 Summer Demand Growth

It is increasingly the case that new or modernised commercial premises and retail outlets are likely to have air cooling installed. Indeed the high level of installed computation in commercial premises (especially 'internet houses') gives rise to a need for air cooling to combat the heat generated by the IT equipment. Where there is a high density of modern commercial and retail premises such as in central business districts, summer peaking demands are likely to be present. A typical example of a summer peaking demand group associated with a retail development is illustrated below.

Figure 15 Typical example of a summer peaking demand group associated with a retail development



The chart is a 'scatter chart' plotting weekday maximum demand against average daily ambient temperature for an entire year. The plot indicates a strong correlation between demand and ambient temperature with a rising trend either side of an ambient temperature of around 12 deg C.

5.6.3.3 ACS and AHS Correction

The correlation between temperature and demand shown above provides a basis for both ACS and AHS (average hot spell) correction. ACS and AHS temperatures can be calculated by taking the average of the minimum and maximum daily average temperatures over a number of years. Demands can then be projected to these temperatures. In the above example, linear extrapolation of data below 10 deg. C, and data above 15 deg. C, has been used to project ACS and AHS demands.

5.6.3.4 Plant Summer Capability

Whilst this section is concerned with dynamic rating of system transformers, it is helpful to understand the factors that govern ratings of plant generally - not least because any consideration of adopting dynamic ratings to transformers will obviously also need to take account of items of plant associated with that transformer. This is particularly relevant to ratings under summer (higher ambient temperature) conditions. Plant summer capability is dependent on the particular critical constraint for the type of plant concerned. Relevant criteria for assigning ratings to major plant items are as follows:

a) **Overhead Lines –** in practical terms**,** the rating of an overhead line is constrained by the need to maintain minimum conductor ground clearances. This is achieved by limiting the conductor temperature to its design temperature - typically 50, 65 or 75 deg C. Ratings for lines constructed to ESI designs are given in Engineering Recommendation P 27. Ratings are specified for single circuit and N-1 conditions in summer, spring/autumn and winter

b) **Underground Cables -** the rating of underground cables is based on limiting conductor temperatures to prevent excessive loss of life. Winter distribution cyclic ratings for various cable types are given in Engineering Recommendation P 17. To produce summer ratings, correction factors for the higher ambient temperature and ground thermal resistivity of soil are applied

c) **Switchgear -** the rating of switchgear is limited by its rated breaking capacity and by its through current rating. Where switchgear also has an assigned fault breaking capability it is the through current rating that will limit the loading capability. Indoor or summer ambient temperatures are used as a basis for switchgear through current ratings. There is no scope in summer to depart from nameplate ratings

d) **Transformers -** the rating of transformers, like underground cables is based on limiting conductor temperature (in this case the winding hot-spot) to prevent excessive loss of life of the insulation. Transformer winding hot-spot temperature is simulated and protection operates to shed load if the temperature is excessive. Emergency cyclic ratings for transformers can be calculated as detailed in BS 7735:1994 or IEC 60354:1991

Practical Application of Real-Time Dynamic Transformer Rating

In order to assign dynamic ratings to system transformers, it is necessary to undertake dynamic modelling using recorded ambient temperature and demand data as per the retail park example above. Where load growth is anticipated and/or new spot loads are to be connected, the anticipated impact on both quantum (and seasonal timing) of maximum demand and daily demand shape is necessary. Using the principles embedded in BS 7735:1994 / IEC 60354:1991 it is possible to derive an equivalent chart to that shown for the retail park above and hence determine the seasonal ambient temperature-related rating for the transformer.

For sites showing adequate capacity headroom, it may be sufficient to apply this derived seasonal dynamic rating without active intervention provided attention is given to closer monitoring in the event of a prolonged abnormally high ambient temperature period. For sites with tighter capacity margins, real-time monitoring of key parameters might be necessary; these would include:

- Ambient temperature (in the case of London observing the known heat island effect);
- Demand (and demand shape - in particular if demand extends well into evening periods affecting the cooling cycle of the transformer);
- Winding temperature.

In the event of a predicted out of firm condition arising, consideration would need to be given to mitigating actions; these could typically include:

- Calculating rate of winding temperature rise of the remaining transformers in the event of loss of one circuit
- Effecting load transfer where available
- Staged voltage reduction (though recognising that where a significant inductive load is present, voltage reduction may be ineffective or even counter-productive in terms of reducing ampere loading
- Initiating, or placing on alert, any demand side response (dsr) contract provisions (typically demand turndown and/or standby generation support)

It is apparent from the above that the development of real-time dynamic modelling tools might be beneficial or even essential in order to ensure adequate advance warning of need, and timely initiation, of mitigating actions.

5.6.4 Costs and cost-benefit

The cost-benefit calculation has been performed using Ofgem's Cost-Benefit Analysis format, which has the following parameters:

Item	Value	
Policy assumptions for applying the solution:	Investment Strategy	Anticipated deferral of reinforcement by minimum 3 years through headroom created by real-time rating
	Engineering Application	EHV/HV (33/11kV) transformers at substations where under N-1 load on transformers will be close to AHS rating
Financial assumptions:	ITC Scheme cost £1.5m (typical) RTTR cost £70k per transformer	
Weighted cost of capital (WACC)	4.1%	
Discount rate	3.5%	
NPV (at years) (based on 3-year deferral)	16 years	£0.09
	24 years	£0.06
	32 years	£0.04
	45 years	£0.02
Additional benefits not quantified	Permits more accurate assessment of true headroom under loading / ambient conditions and avoids possibility of premature reinforcement / asset stranding	
Assessment Result	Flexibility and potential for further benefits	

5.6.5 Data assurance

Case study of a Site with Marginal Summer Firm Capacity

The retail site concerned with the above chart is supplied by two 12/24MVA OFAF[7] transformers and has remote control and manually switched transfer capacity to adjacent sites. The transformers each have a nominal continuous emergency rating (CER) of 24MVA at an ambient temperature of 5 deg C.

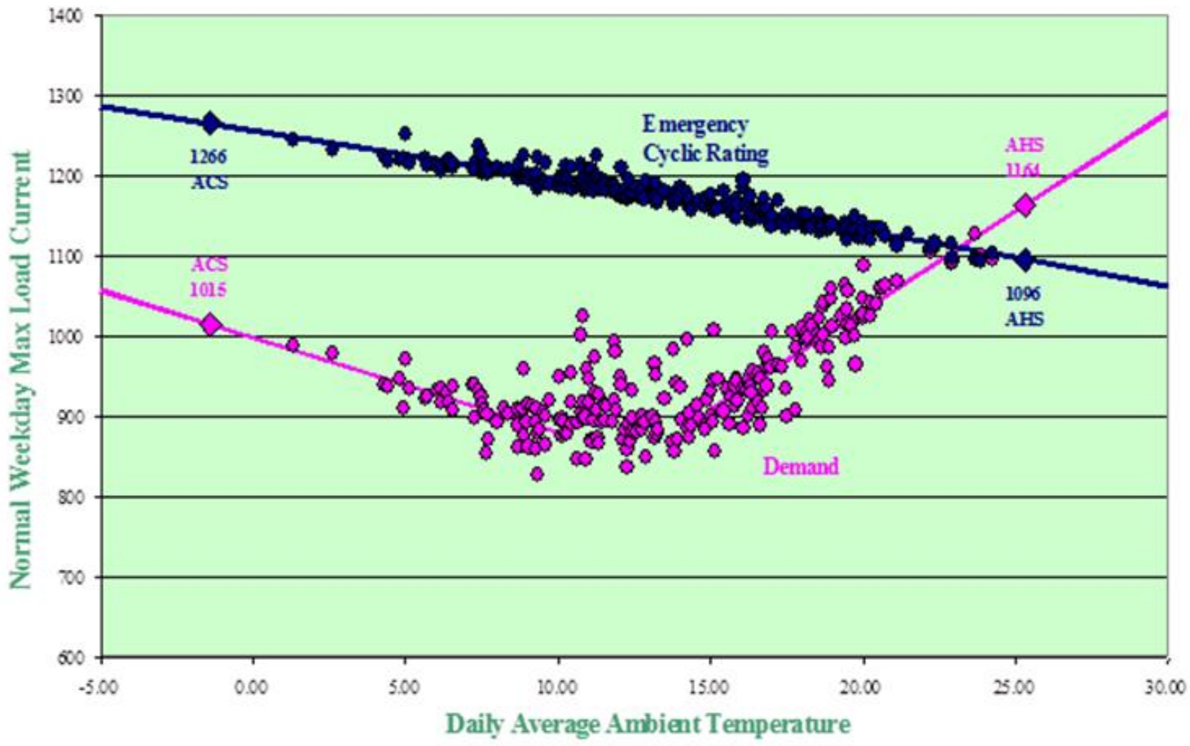
Using the principles described in BS 7735 / IEC 60354, demand and temperature data can be combined to produce an emergency cyclic rating profile that can be compared with the demand profile. However, important factors that need to be taken into account include:

- Ratings of bushings and ancillary equipment such as tapchangers (selector and diverter switches) which, like switchgear, have no scope in summer to depart from nameplate ratings. Note that while tapchangers could be locked on loss of one circuit preventing further tapchange operations, their rated load carrying capacity must not be exceeded
- De-rating factors due to any enclosures (e.g. noise enclosures)
- Winding temperature protection trip settings are typically set at around 120 deg C to ensure the maximum acceptable winding hot-spot temperature of 140 deg C is not exceeded (though exceeding the 120 deg C trip setting is permissible provided real-time rate of temperature rise is available to ensure tripping in the event that 140 deg C is likely to be reached)
- Overcurrent protection settings which in some cases may necessarily have been set at levels close to single-circuit outage peak loading conditions
- The number of days of operation under emergency rating conditions before unacceptable loss of transformer life occurs

In the figure below, the dynamic (ambient temperature dependent) rating of the transformer is superimposed over the previous chart. This demonstrates that whilst it would be possible to extend the rating of the transformer under winter loaded conditions, for the loss of one transformer in summer, the demand would exceed the emergency cyclic rating of the remaining transformer if the average daily ambient temperature exceeded 23 deg C.

[7] OFAF - oil forced / air forced – i.e. at 24MVA both oil circulation and air radiation are forced through pumps and fans respectively

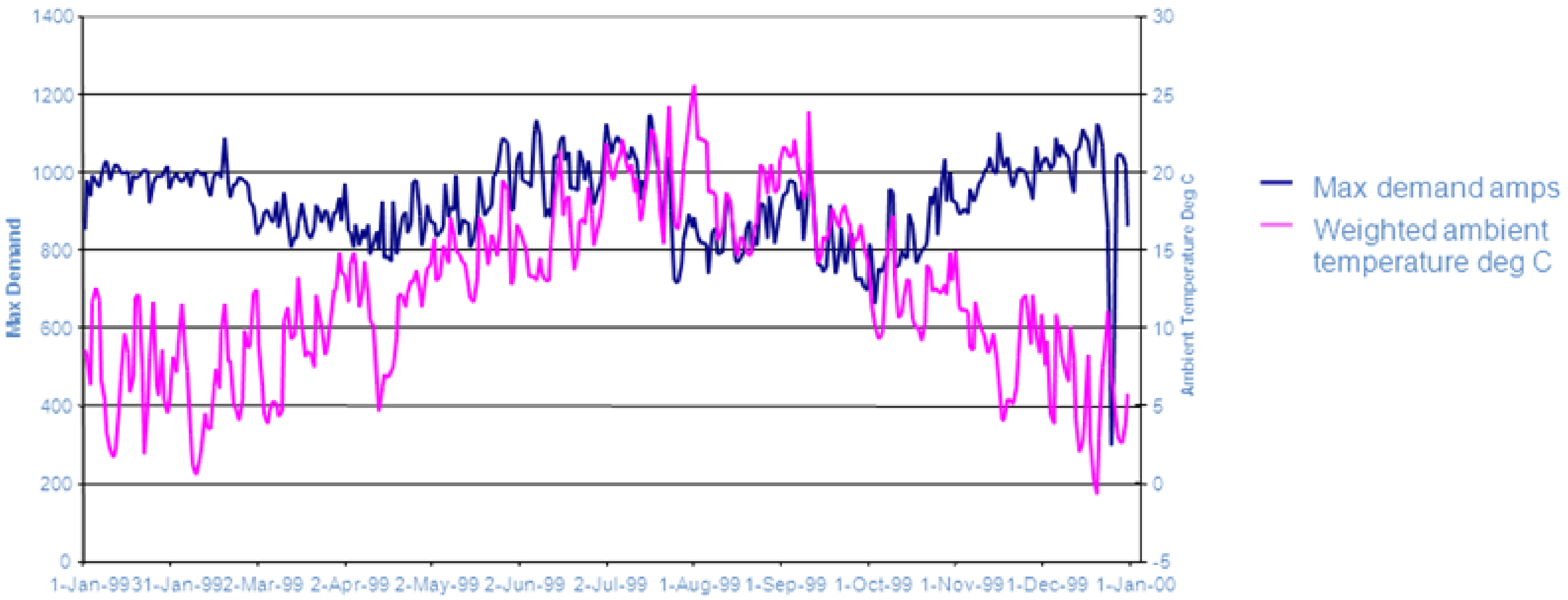
Figure 16 Limiting factors for dynamic rating



Central London CBD

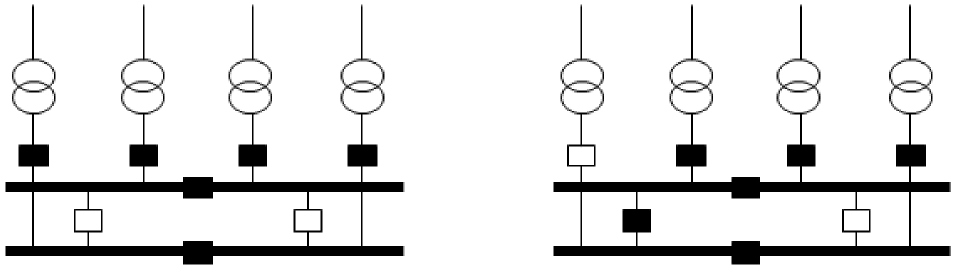
Central London is a particular example of a CBD with a high summer loading characteristic. A typical loading characteristic is shown in the chart below and makes for interesting comparison with the chart for the winter loaded substation shown previously. Whilst a similar negative correlation between ambient temperature and demand can be observed during winter, this correlation becomes distinctly positive over the summer period.

Figure 17 Example of a CBD with a high summer loading characteristic



A common substation configuration in London is for a double-busbar switchboard with bus section and bus coupler circuit breakers supplied by 4 transformers. For normal operation these are configured as two groups of 2 because with 4 transformers operated in parallel the fault rating of the switchgear would be exceeded. When operated under N-1 conditions they are reconfigured (automatically in the case of an unplanned outage) to operate with the busbars coupled.

Figure 18 Different busbar arrangements



Transformer ratings

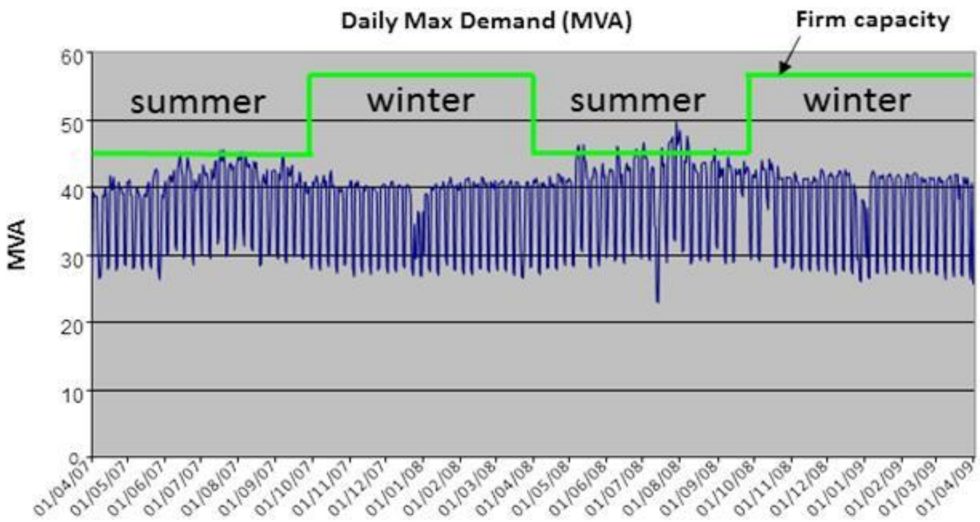
Transformer ratings can be extended beyond their nameplate ratings provided consideration is given to their loading cycle and the ambient temperature operating conditions. In the case of the above 4-transformer substation, the transformers would typically be 15MVA ONAN[8] units. This gives a firm nameplate rating for the substation of 45MVA (i.e. under N-1 conditions).

Under typical ambient conditions, it is possible to assign a nominal 30% overload rating to the transformers, which gives a firm rating of 58.5MVA[9]. However, under extreme summer ambient temperature conditions, no more than the nameplate rating can be assumed, giving rise to a firm capacity of just 45MVA. The following chart shown previously in this document in relation to DSR, illustrates the inherent limitation of this approach for a typical central London CBD substation site with high summer period loading.

[8] ONAN – oil natural / air natural – i.e. cooling is effected through natural convection and radiation without forcing

[9] 20% for transformers designed to former CEGB standards – i.e. giving a firm rating of 54MVA

Figure 19 Summer and winter differences



The chart shows that whilst under winter conditions there is ample capacity headroom, under summer conditions firm capacity is actually exceed on some days.

In practice, there is no seasonal step change in transformer rating or, hence, substation firm capacity. As illustrated above, transformer rating is dependent on cyclic loading conditions and average daily ambient temperature and hence in reality is dynamic. It follows that a simplistic approach to seasonal rating may result in underutilisation of the asset and potentially premature reinforcement. Conversely, as the above analysis has shown, there is also a possibility that under extreme summer ambient conditions, even the nameplate rating might be unsustainable for extended periods.

5.7 Partial discharge monitoring

5.7.1 Need case

Switchgear has been identified for replacement for a variety of reasons including defects, poor condition, poor mechanism performance and poor insulation performance. For equipment with concerns over insulation performance, on-line PD monitoring can help defer the replacement by continuously monitoring the state of insulation and flagging when it starts to deteriorate to an unacceptable condition.

Partial Discharge (PD) activity is a useful indicator of insulation health in high voltage switchgear. Common causes of PD are:

- Voids or discontinuities within solid insulation
- Contamination, damage or condensation on insulation surfaces
- Moisture ingress into insulation materials
- Irregularities in the thickness of insulation due to manufacturing defects
- Bubbles in liquid insulation
- Sharp edges of conductors
- Loose electrical connections

The level of PD depends on the nature of the defect and also varies with the applied voltage, temperature and humidity. The damage caused by PD depends on several factors, ranging from negligible or intermittent through to disruptive failure. The time to failure from inception of PD can range from days through to many years.

There are two main on-line techniques commonly used to detect discharge: Transient Earth Voltage (TEV) used to detect RF emissions induced in earthed metalwork, which works best on metal-clad switchgear with solid insulation; and ultrasonic detectors which can be used to pick up acoustic emissions and work most effectively on plant with a clear air path to the source of discharge.

As an example, the graph below shows the number of Grid and Primary 11kV circuit breakers in EPN that are predicted to be HI4 or HI5 during ED1 both with and without intervention. Full details are provided in the annex to our business plan describing our investment plans for switchgear.

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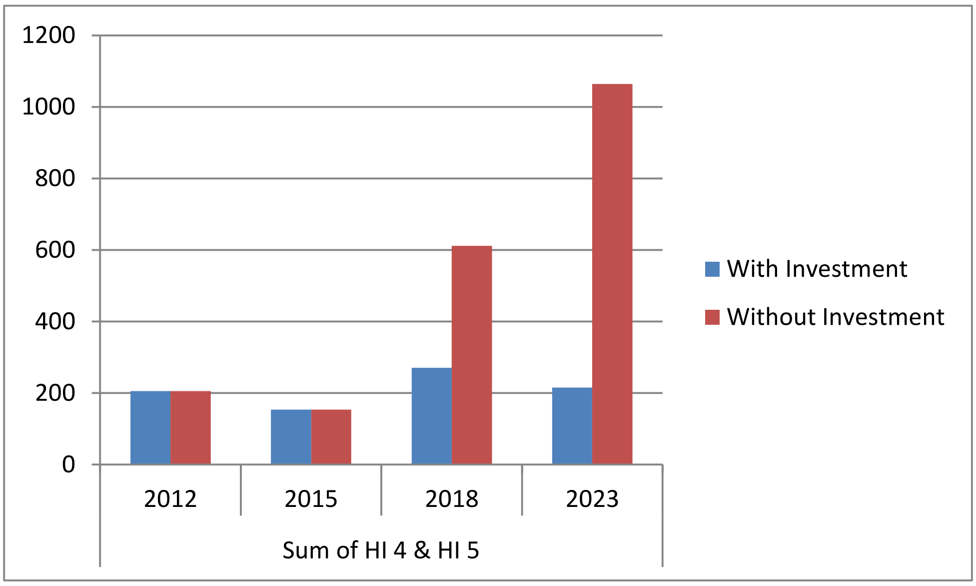
As an example, Figure 20 shows the number of Grid and Primary 11kV circuit breakers in EPN that are predicted to be HI4 or HI5 during ED1 both with and without intervention. Full details are provided in the annex to our business plan describing our investment plans for switchgear.

Figure 20 HI4 and HI5 Grid and Primary 11kV circuit breakers with and without intervention (EPN).



On-line PD monitoring equipment will be installed on some switchboards at Grid and Primary sites where the primary driver for replacement is insulation condition.

In our experience, the following switchgear types usually have insulation condition as the replacement driver, and are therefore currently considered suitable for on-line monitoring:

- GEC VMX
- Reyrolle LMT
- AEI BVAC
- Brush VSI
- Reyrolle L42T

However, this list is not exhaustive and any switchgear where insulation condition becomes a concern could be considered.

The majority of switchboards considered for deferral will be equipped at the start of the RIIO ED1 period, and the monitoring will be in place for a minimum of one year before the scheduled replacement date. By doing this, a much better idea of the insulation condition can be gathered and provided the switchboard is free of discharge, the replacement will be deferred until the condition starts to deteriorate or another replacement driver, such as mechanism condition, becomes apparent.

Once the monitoring equipment is installed, the following policy will be applied:

- A switchboard replacement will be deferred by 5 years if it remains free of discharge <u>or</u> the source of the discharge can be eliminated in a cost effective manner
- A switchboard replacement will proceed as planned if another replacement driver such as the condition of the mechanism becomes apparent, <u>or</u> discharge is detected and cannot be eliminated in a cost effective manner (e.g. busbar or multiple components)

5.7.2 Cost-benefit summary

The asset replacement expenditure plan has been re-evaluated, resulting in minor changes to the switchgear replacements planned in LPN; a reduction in the number in EPN and an increase in SPN. The same overall level of savings delivered through online partial discharge monitoring is being offered as in our June 2013 plan.

Item	EPN	LPN	SPN	all DNOs
Costs of conventional reinforcement [1]	£152.3m	£53.6m	£59.7m	£265.6m
Savings from deferred replacement [2]	- £2.3m	-£2.9m	-£5.5m	-£10.7m
Cost of implementing Smart Grid options [3]	£0.4m	£0.5m	£0.9m	£1.7m
Total	£150.4m	£51.2m	£55.1m	£256.6m
Net saving	£1.9m	£2.5m	£4.6m	£9.0m

[1] Non-load related switchgear replacement.

[2] Savings achieved by deferring approximately 35% of the monitored sites by 5 years (starting from year 3 of the ED1 period).

[3] Based on a total of 30 sites being equipped at the start of the ED1 period (£30k per site) and £100k annual operational expenditure to cover equipment maintenance, data analysis, remote communications and field work to investigate defects identified.

5.7.3 Data assurance

As part of its DPCR5 innovation programme, UK Power Networks has been heavily involved in the development of the Partial Discharge Monitoring Technology for switchgear and cable. The online condition monitoring project carried out under the Innovation Funding Incentive (IFI) has resulted in the development in a suite of equipment and a platform to remotely detect and monitor PD trends (as reported in UK Power Network 2011/12 IFI report).

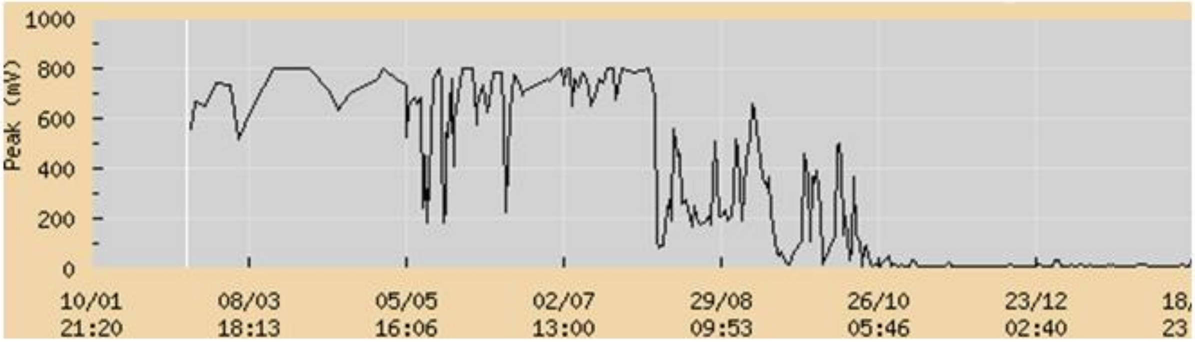
Following the completion of the IFI project:

- The technology has been embedded into the business and owners within our asset management and Network Operations departments defined
- A formal policy has been written (Engineering Design Standard 10-0004: Improved Management of HV Cable and Switchgear Using Online Partial Discharge Technology)
- A contract for the existing fleet has been negotiated with the main supplier of the technology (IPEC Ltd)

UK Power Networks has also carried out several preventive switchgear repairs as a result of remote PD detection (see examples highlighted on the next page).

These successes, our experience of trialling the Partial Discharge Monitoring technology for the past 7 years and the knowledge relating to switchgear degradation process acquired through our participation to the Partial Discharge User group are giving us the confidence that Partial Discharge Monitoring can be utilised to defer selected switchgear replacement schemes.

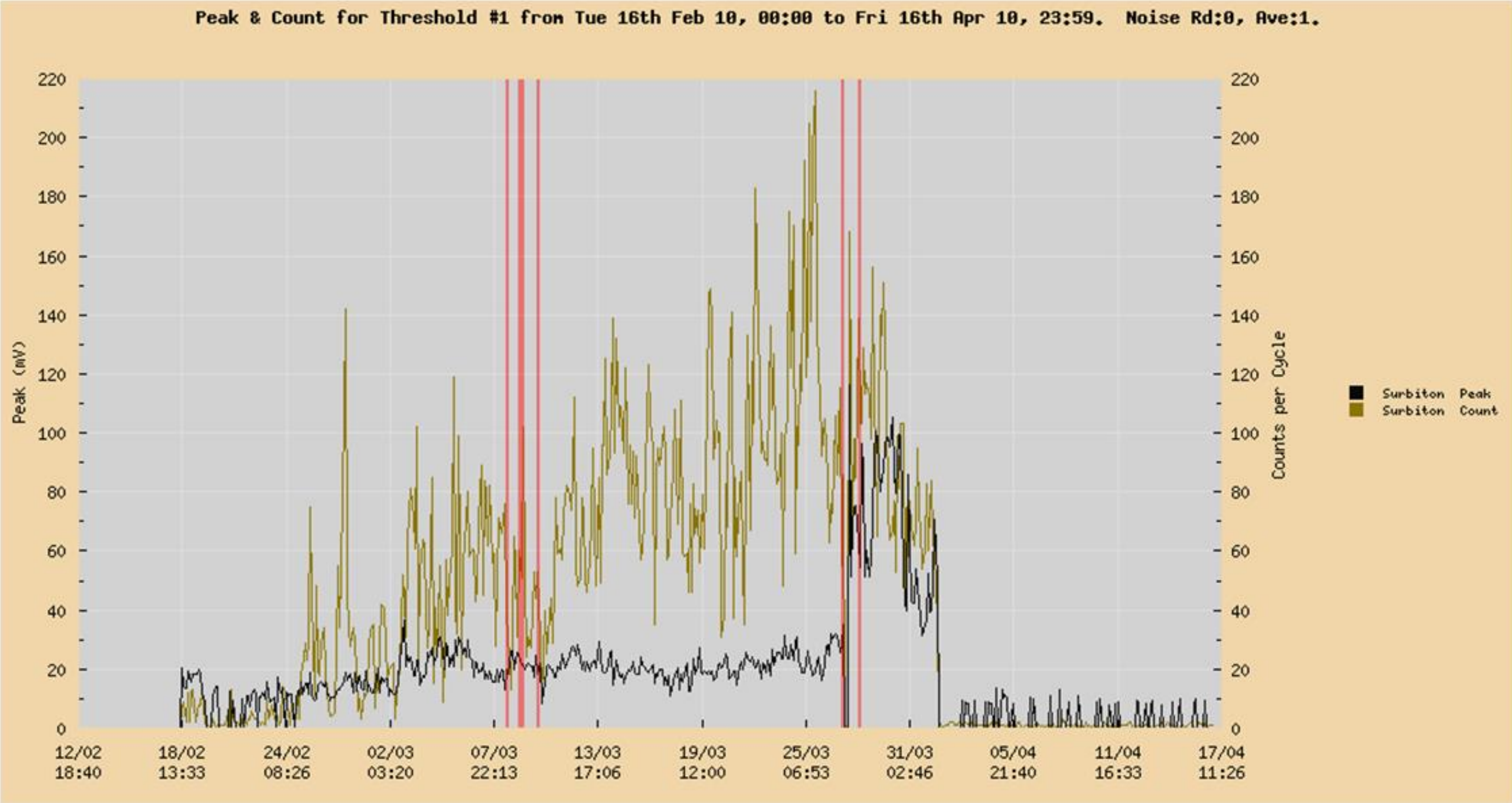
Figure 21 Merton primary substation preventive repair



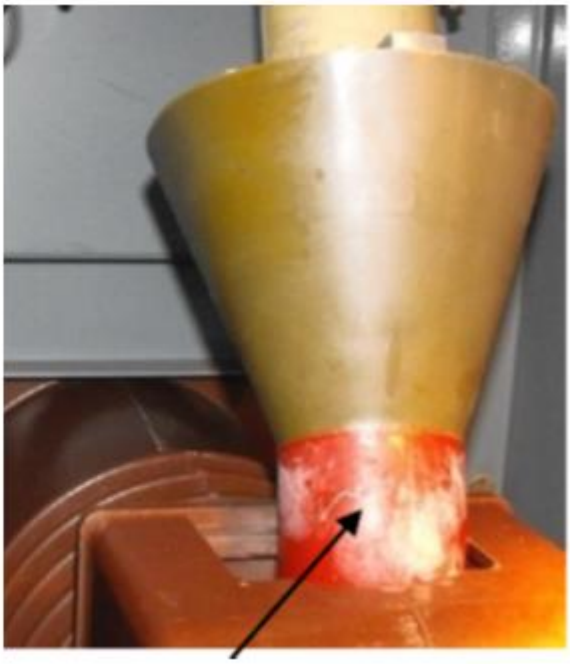
PD Activity trend remotely detected

Evidence of discharge

Figure 22 Kingston grid preventive repair



PD Activity trend remotely detected



Evidence of discharge in CT chamber

5.7.4 Costs and cost-benefit

The cost-benefit calculation has been performed using Ofgem's Cost-Benefit Analysis format, which has the following parameters. The investment strategy consists of targeting switchboard replacements which would otherwise have cost £1 million, and to defer a proportion of those which are selected for monitoring. As shown below, the CBA is supportive of our approach on the assumption that 35% of sites selected can be deferred; and taking into account the additional benefit that once a site is equipped with monitoring, it is relatively simple to upgrade the site to also monitor the attached feeders. Monitoring the health of attached feeders has the potential to improve reliability of supplies by detecting faults in feeders.

The cost of the partial discharge monitoring equipment and associated operational expenditure has been calculated from a UK Power Networks negotiated price list.

Table 10 Solution: Partial Discharge Monitoring

Item	Value	
Policy assumptions for applying the solution	Investment Strategy	Defer £1 million by 5 years
	Engineering application	Grid and Primary sites where the primary driver for replacement is insulation condition
	30 Grid and primary sites (where the primary driver for replacement is insulation condition) to be equipped at the start of the ED1 period.	
	Baseline scenario: 35% (11) of the monitored sites can be successfully deferred.	
Financial assumptions for applying solution	Switchboard replacement average cost: £1m Average cost of On-line Partial Monitoring equipment: £30k OPEX cost for 30 sites: £100k/year	
Weighted cost of capital (WACC)	4.1%	
Discount rate	3.5%	
NPV (at years)	16 years	£0.69
	24 years	£0.22
	32 years	-£0.12
	45 years	-£0.49
Additional benefits not yet quantified	The Online Partial Monitoring equipment will also enable to monitor underground cables.	
Assessment result	Flexibility and potential for further benefits	

5.8 Fault current Limiters

5.8.1 Introduction

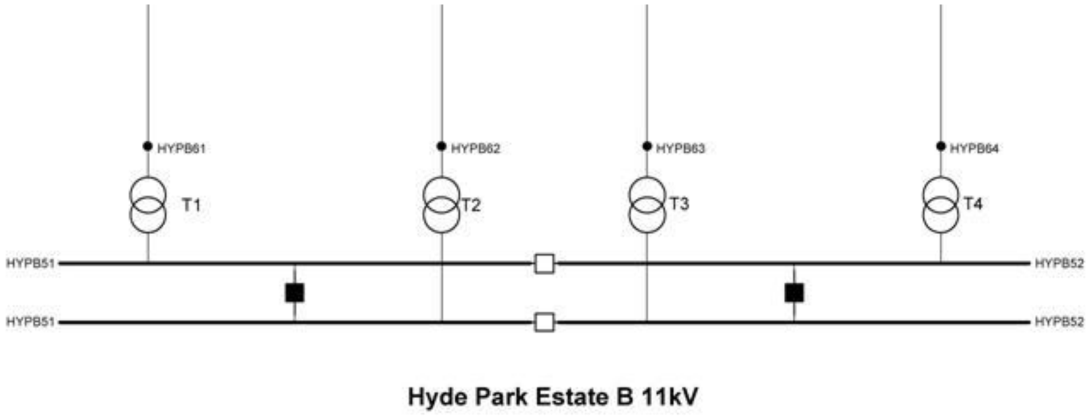
There is a recognised issue with increasing Fault Level on the distribution network, particularly the 11kV networks within dense urban areas. This is exacerbated by the desire to install more low-carbon distributed generation on the network, along with some current policy decisions requiring it in new developments. Recognised solutions to this problem have existed for many years – from splitting the network to installing series reactors. However, these solutions create issues of their own, for example poorer load sharing leading to reduced utilisation and flexibility; and increased circuit reactance leading to greater voltage regulation and higher losses.

5.8.2 Need case

Our LPN network is almost entirely urban. 86% of the LPN Main Substations (MSS) normally operate with the 11kV bus-bars split. Under single transformer outage conditions approximately 20% are operating at above 95% switchgear fault level rating, and approximately 80% above 85% fault rating.

The historic standard design of the LPN MSS included 4x 15MVA transformers, normally run in pairs. They are designed and specified such that in the event of a transformer or in-feed failure the remaining 3 transformers are able to supply the site load with the busbars running ‘solid’ and still remain within the switchgear fault rating. Whilst very efficient in terms of transformer utilisation, this arrangement allows little headroom for additional fault level contribution from generation, or for an increase in transformer capacity without also increasing transformer impedance (or introducing in-line reactors) leading to higher losses. In a number of cases, generation is connected under an inter-tripping arrangement whereby, in the event of a transformer feeder fault outage leading to auto-coupling of the busbars, generation is automatically disconnected from the network.

Figure 23 Hyde Park Estate system configuration



Due to the age of many of these sites much of the switchgear is approaching end of life, allowing for the natural replacement with switchgear with a higher fault rating. Where this is not the case, the cost of alleviating a fault level constraint is assessed taking into account key factors such as (often very limited) available space.

5.8.3 Costs and cost benefit analysis

At this time Fault Current Limiters (FCLs) are a relatively immature technology and hence little is known about their whole life costs. While in some cases FCLs can present a cheaper short term solution to switchgear replacement there is some uncertainty about delivering value from the whole life of the equipment. We are involved in a project funded by the Energy Technologies Institute to investigate the technology and have installed a prototype FCL from GridON Ltd in a substation in Sussex. Discussions are on-going with GridON to look to develop the technology further.

Due to this uncertainty, and the practical difficulties in integrating FCLs with existing substation switchboards, **there are currently no proposals in our Business Plan Submission for schemes including FCLs**. However, this position will be reviewed once we have gained sufficient experience from our own trials and those being conducted concurrently by other DNOs.

A possible **earlier application of FCLs could be to facilitate the connection of generation** to networks already operating close the fault rating of the associated switchgear. Installing a FCL either within a MSS in series with the circuit connecting the generator or at the site of the generator could enable a closer or lower voltage connection, reducing the connection costs significantly and potentially providing a faster connection. This could apply particularly to Combined Heat and Power schemes common in urban areas, but also to any rotating plant generation with a significant fault level contribution (particularly synchronous generation which will contribute to circuit-breaker breaking duty as well as switchgear making duty).

We are open to discussing options for using FCLs with prospective generation customers or customers with existing generators currently unable to parallel with our network due to fault level constraints.

5.9 Active network management

5.9.1 Introduction

As part of two of its flagship LCNF projects, Low Carbon London and Flexible Plug and Play Low Carbon Networks, UK Power Networks is trialling an Active Network Management (ANM) approach to offering faster and cheaper connections to distributed generators that are seeking connections to constrained parts of the distribution network.

The ANM system monitors specific constraint locations in real-time and manages the output of the generators in order to maximise their export onto the network while keeping the network operational parameters within limits. It can be used to manage different types of constraints such as thermal, voltage, reverse power flow and fault level constraints.

An active network approach can provide network access to distributed generation without the need for expensive reinforcement. This translates into cheaper connection quotes for generation customers. However, the need to control the generation output will require some voluntary curtailment by the customer. The connections offered under the active network management approach are defined as interruptible or actively managed connections.

The overall architecture for the system deployment comprises of network monitoring devices and a software-based control scheme. The ANM system can deliver a number of different applications and functionalities such as power flow management, voltage management and real time ratings of overhead lines and also interoperate and enable technologies such as the dynamic rating of overhead lines. Suitable telecommunications links between the generator site and the ANM server location are required in order to enable the implementation of this technology.

In addition, a commercial framework that will define and govern access to the distribution network under interruptible terms is required. Under the FPP project, UK Power Networks has developed a network access methodology based on shared access. This will complement the already tried and tested Last-In First-Off approach.

5.9.2 Costs and customer benefits

The work that UK Power Networks has carried out under the Flexible Plug and Play Networks project indicate that significant benefits can be delivered to the Customer by signing up to an interruptible connection. In many instances, the upfront capital saving of the interruptible connection when compared with the traditional reinforced solution outweighs the additional costs resulting from lost output.

The table below illustrates the above point by comparing the connection costs using the traditional business-as-usual approach including reinforcement and the connection costs based on actively managed method as trialled by the FPP project. The projects on the table are actual customer generation projects that have been offered a connection using the ANM method in the FPP trial area in Cambridgeshire.

Generator	MVA	Tech	BAU offer	FPP offer	Savings
Generator 01	– 8.00	– Wind	– £3,508,930	– £881,611	– 74.9%
– Generator 02	– 0.50	– Wind	– £1,891,200	– £234,779	– 87.6%
– Generator 03	– 10	– Wind	– £4,827,000	– £590,818	– 87.8%
– Generator 04	– 5	– Wind	– £1,185,000	– £649,788	– 45.2%
– Generator 05	– 1.50	– Wind	– £1,950,000	– £157,137	– 91.9%
– Generator 06	– 1	– Wind	– £2,050,000	– £384,711	– 81.2%
– Generator 07	– 10.25	– Wind	– £5,244,247	– £1,584,000	– 69.8%
– Generator 08	– 0.5	– CHP / AD	– £1,900,000	– £350,000	– 81.6%
– Generator 09	– 2.4	– PV	– >£2,000,000	– >£ 200,000	– 90.0%
– Generator 10	– 0.5	– CHP / AD	– £2,500,000	– £117,474	– 95.3%
– Generator 11	– 6.6	– PV	– £9,000,000	– £1,734,877	– 80.7%
– Generator 12	– 0.5	– Wind	– £830,000	– £61,293	– 92.6%
– Generator 13	– 7	– PV	– >£5,000,000	– £997,903	– 91.3%
– Generator 14	– 4	– PV	– £2,000,000*	– £800.00**	– 99%
– Generator 15	– 0.25	– PV	– £57,596*	– £750.00**	– 98.7%
– Generator 16	– 1.50	– CHP	– >£4,000,000	– £127,683	– 96.8%
– Generator 17	– 6.93	– PV	– £4,000,000	– £390,780	– 90.2%
– Generator 18	– 0.50	– PV	– £9,000,000	– £385,147	– 95.7%

The above FPP connection costs do not include the project funded (covered by the project budget) elements of the solution which are the costs for the ANM system and telecommunications platform design and deployment.

The latest estimate for the costs of the ANM system and telecommunications platform for the FPP project are in the range of £2 million. However, the infrastructure installed can serve a significant amount of generation customers and its cost model significantly benefits from economies of scale.

The financial savings from using the smart approach of actively managed connections look favourable and these are directly attributable to generation customers.

An additional benefit is the speed of delivery of the connection assets. Due to the fact that reinforcement is not required for the actively managed connections, the planning/wayleaves and actual physical construction works take less time and the time for connection offer acceptance to energisation is reduced.

Given the increased demand for generation connections and the various constraints that appear in certain parts of the UK Power Networks, the Active Network Management approach is expected to have significant take-up during ED1 particularly in the Eastern and Southern licenced areas and provide the customers with a flexible option for a cheaper and faster connection where possible.

5.10 ICT to enable smart

The definition of Smart Grids defined earlier in the document made clear that enabling communications and Information Technology infrastructure is an essential element. The period comprising the RIIO-ED1 and RIIO-ED2 period is also clearly a particularly important period for the wide-scale adoption of low-carbon technologies and, in response, Smart Grid solutions. There is an awareness that enabling IT infrastructure would have both a lead time to roll-out but also potentially faster lifecycles and therefore an increased risk of being 'stranded' or rendered obsolete if installed too early.

Clearly our decisions to invest or defer investment in enabling ICT for Smart Grid solutions are important. In considering this issue we have drawn on three tools:

- The qualitative assessment of technologies, including enabling technologies such as ICT, contained in our Future Network Development Plan
- The Transform model's global cost-benefit analysis of the investment in enabling ICT
- The Transform model's ability to predict 'tipping points' at which the investment in an enduring ICT solution is required to support the volume of LCT uptake or Smart Grid solutions being deployed

The outcome of this has been that UK Power Networks does not at this stage see a defensible case for building significant investment into ICT for Smart Grids into our base business plan. We have built in a small incremental amount, but not a significant or material increase on our year-on-year expenditure on ICT, as might be supported by some of the model outcomes and in some scenarios. We are in the first instance looking to the opportunity offered by the Innovation Roll-out Mechanism and/or the low-carbon device uptake calculation factored into the Load Related Expenditure Re-opener should we need to re-visit this decision during the RIIO-ED1 period.

In the meantime, we will ensure that we fully exploit the functionality of the national smart metering system - including SMETS2 compliant meters, and the DFCC communications system - to improve our management of load flows, voltage levels and power outages. Whilst this requires investment in data management and aggregation systems by fully exploiting smart meter data flows and the communication channels we can reduce our need to invest in our own 'last-mile' ICT infrastructure.

Importantly we are planning for the steps that we might need to take at each 'trigger point' or 'tipping point'. Our experience is that our innovation projects or trials once they move into a Business-as-Usual mode in small volumes are normally best accommodated with a tactical solution to their ICT requirements. Only once the Smart Grid solution is being used in large volumes does it become viable or necessary to put in place a more robust and enduring architecture. The tipping point will almost always be recognised by the business itself as the tactical solution begins to show weaknesses and is stretched as it copes with larger volumes. By thinking ahead of time about what the enduring solution might look like, we can be sure to commence the movement from tactical to enduring solution in sufficient time to meet the challenge.

5.10.1 Qualitative assessment

Using our DECC and UK Power Networks business planning scenarios, we have built our internal Smart Grid strategy with an awareness of a number of possible economic and policy environments which might emerge over the ED1 period. Whilst these economic and policy environments are not a one-for-one match with DECC's 4th Carbon Budget scenarios, we believe they are sufficiently consistent to offer valuable insight into the network investment implications of credible scenarios surrounding levels of economic growth, low carbon technology take-up and market developments.

As such, in the Future Network Development Plan not only Smart Grid solutions but also the enabling technologies required to support them are exhaustively categorised, and qualitatively assessed as to their maturity, cost, availability, their requirement for further research or trialling and their relevance in each of the economic and policy scenarios. The results of this are illustrated in the diagram below.

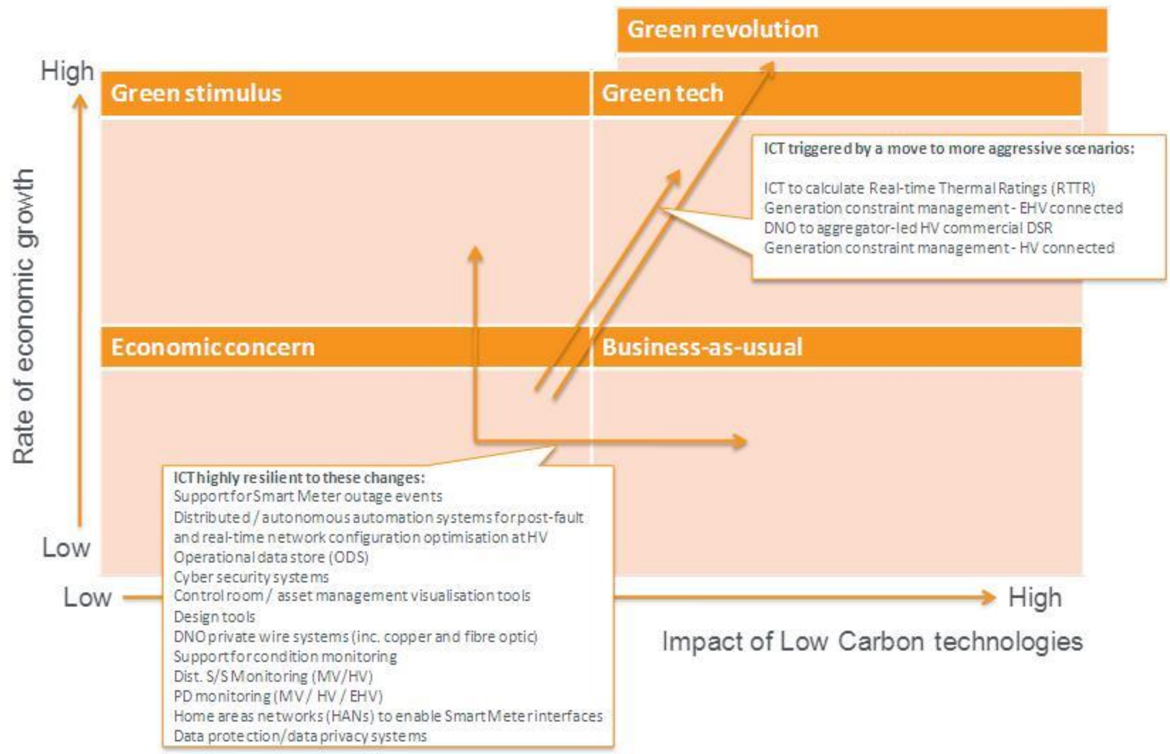
Each of the enabling solutions has been given a qualitative assessment of their relevance in each of our five originally defined scenarios (Economic Concern, Business As Usual, Green Stimulus, Green Tech and Green Revolution) and our 'core' scenario which we are adopting following extensive stakeholder consultation. The qualitative assessment consists of a score from 0 (not at all relevant to that scenario) to 3 (highly relevant to that scenario), thus arriving at a total score between 0 and 15 of the solution's relevance to all scenarios or 'resilience'. The implication is that an enabling ICT solution with a qualitative score of 15 will be an essential requirement in any circumstance, and an enabling ICT solution with a qualitative score of 0 is either not mature enough to be brought to market in the foreseeable future or bears little relevance to the UK energy sector at this time.

Note that the Economic Concern, Business As Usual and Green Stimulus scenarios are closely related, requiring only a change in either, but not both, of the economic growth rate or the low carbon uptake.

Our core planning scenario, a hybrid scenario developed with our stakeholders, takes a more conservative approach in a number of areas including assumptions around the rate of take-up of low carbon technologies and lies roughly on the boundary of the Business As Usual and Green Stimulus scenarios.

By contrast, the Green Tech and Green Revolution scenarios require changes in both the economic growth rate and the low carbon uptake, and then have a dependency on the market's response to the government's Electricity Market Reform proposals.

Our business plan proposals are based on the premise that it makes most sense to invest in the enabling ICT solutions which are robust to any of the three scenarios Economic Concern, Business As Usual and Green Stimulus. The ICT solutions shown in the bottom-left hand section of the diagram fulfil these requirements, all scoring 10 or more out of a total score of 15 across all five scenarios, and a score of 5 or more out of a total score of 9 across the scenarios Economic Concern, Business As Usual and Green Stimulus.



We have separated in the diagram additional ICT solutions which are still somewhat relevant to the three cases Economic concern, Business-as-usual and Green stimulus, but are particularly triggered should either of the Green Tech and Green revolution scenarios materialise.

As a result, our activities include the following:

- Our existing IT roadmap which will deliver before RIIO-ED1 commences includes the commissioning of new functionality which will allow autonomous sectionalisation of the 11kV network after a fault to a greater degree than today
- Activities to ready our systems, including our Operational Data Store (ODS), to support the Smart Meter roll-out and particularly to better support outage management. The details of this are the associated business case are set out in a companion document, our Smart Metering Strategy
- We are reviewing our network planning and design tools alongside our IT transformation project being conducted over the next two years. Further details can be found in the companion document explaining the scope of the transformation project. This is self-funding within the existing price control (DPCR5)
- We have demonstrated new visualisation tools and enabled additional substation monitoring which are already running on our live systems as a result of the Low Carbon Network Fund (LCNF) Tier 1 project 'Distribution Visibility' and have factored the ongoing operational costs of this into the operational IT expenditure within our business plan
- We have demonstrated adherence with the Data Protection Act in managing the data from over 5,000 trial participants in the Low Carbon London project and have a fore-runner of a customer data privacy system in place within the Low Carbon London project
- The ICT to support Partial Discharge monitoring is largely in place, and any extension and on-going costs will be self-funding from within the savings listed already in this document

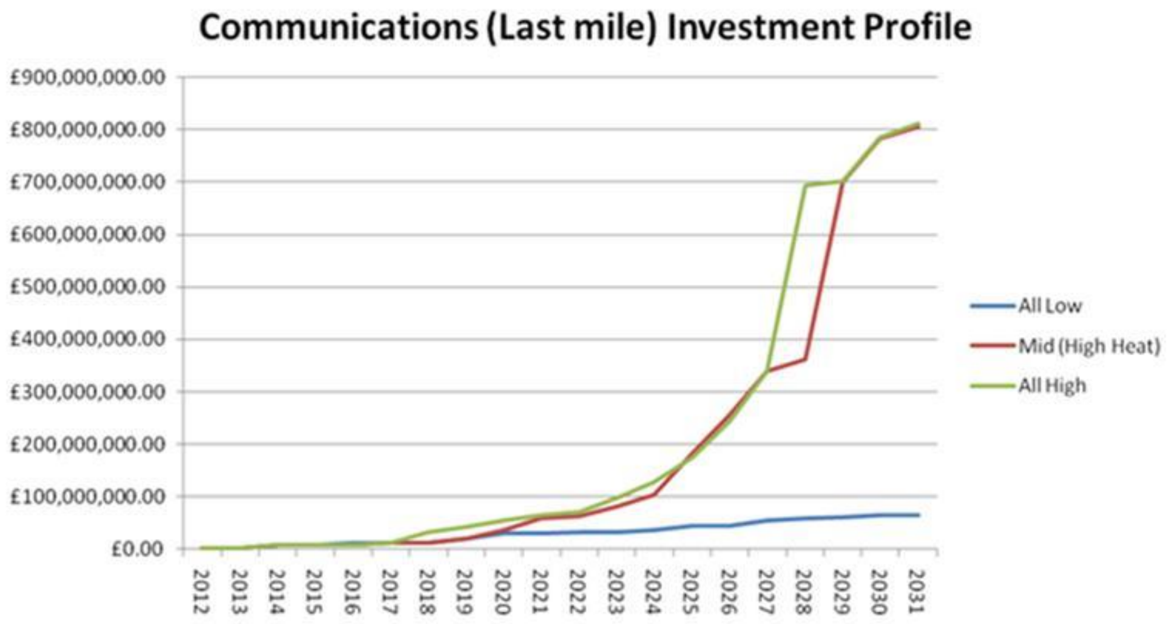
As part of our preparations for the 2012 Olympics we studied the resilience of our IT infrastructure to cyber-attack and are aware that this will be a growing issue over the coming years. Finally, we are watching with interest the final specification and selection of Home Area Network (HAN) which will enable the interface from In-home Displays (IHDs) to Smart Meters, given the vital role of In-home Displays to facilitate behaviour change in customers and to encourage demand to follow generation.

In addition to these activities, we have actively carried out early thinking about the evolution of our IT systems which will be required to support Active Network Management, Demand Side Response and Low-Voltage visibility, and which will be discussed below. Clearly these cover a number of areas which would be critical in the event that one of the more aggressive scenarios (Green Tech or Green Revolution) materialise.

5.10.2 Quantitative assessment

Aware that the RIIO-ED1 and RIIO-ED2 periods cover 16 years, we have concentrated on looking at GB-wide trends in carrying out our quantitative assessment. An example output is shown below in which we have looked at the forecast expenditure which may be required by the GB DNOs on 'last mile' communications infrastructure. This forecast has been generated by the GB version of the Transform model.

Figure 24 Example of estimated investment required to support smart grids across the GB in a number of DECC's low carbon uptake scenarios



Clearly there is an extremely wide variation and one which does not justify investment at this stage, until we are more certain of the future. Outputs for other enabling ICT items have similar profiles. This has led us to place more weight on our qualitative approach, and separately ensuring that we have an internal picture of how the requirements of ICT may realistically evolve. We believe that the Tipping Point and Trigger point indications in the Transform model will be useful in this regard moving forward, but believe there is too much uncertainty at this stage to use them for investment planning.

5.10.3 Tactical and enduring ICT architectures

As discussed above, we have carried out initial thinking on how the ICT architecture might need to evolve within UK Power Networks in order to deliver on the savings that we are committing to from, for example, Demand Side Response.

The diagram in Appendix B shows three architectures side-by-side: the first is the current architecture which is sufficient to trial the concept, and represents a reasonable level of investment until the solution has been proven successful. The second architecture is a 'tactical' ICT solution which removes some of the manual processes involved in the trial configuration, thereby increasing the scalability and reliability of the solution. But we still expect at some point that this architecture itself will be shown to be insufficient and will need to be replaced by and enduring or 'enterprise' ICT architecture.

In the example shown the trial architecture is deliberately shown outside of the existing UK Power Networks IT operational systems, which are only introduced as a landscape in the second architecture diagram. This represents the fact that during their trial stage, frequently Smart Grid solutions are running on a shadow or 'parallel' infrastructure. The assessment of whether Demand Response has been successfully dispatched at the right level and for the right duration is carried out manually by observation of measured data after the event ('Manual DR analysis and tracking'), dispatch itself takes place by telephone, and financial reconciliation and payment is manual. Communications technologies being used to connect with customer premises and/or aggregators are the existing communications backbone, stretched for this purpose.

By contrast, the tactical solution provides the company with a more resilient, auditable and traceable solution for achieving Demand Response on larger scale. We would expect the establishment of the tactical solution to be self-funding from within the RIIO ED1 savings highlighted in this document. The tactical solution will involve re-assessing the communication requirements to ensure that the legacy solution is fit for purpose for larger volumes of traffic, and critically puts in place automated links to dispatch demand response and to carry out financial reconciliation and payment based on proven dispatch. As we incrementally add more 'end-points' to our ICT network, representing both aggregators and customer sites, we increase our attention to cyber-security and unauthorised access to our systems from these endpoints ('Access management').

The enduring solution begins to place greater weight on managing the volume of information coming in, both implementing a 'Head-End' to triage traffic, and implementing greater visualisation tools to allow control managers to increasingly manage a portfolio of Demand Response as opposed to multiple individual sites. The enduring solution is expected to require the most significant investment, and is the point at which entire products may need to be replaced with new, more capable products.

By following this approach, we can think through the implications of Smart Grid technologies ahead of time, have an easy point of reference to check whether day-to-day ICT upgrade programmes may have an impact on, or should be future-proofed to support, the requirements of Smart Grid technologies. In particular, these diagrams provide the detail of what will actually need to be implemented between the 'Tipping Point' and 'Trigger Points' identified by the Transform model.

5.11 Our view on innovation during ED2 and ED3

The key focus above have been our deliverables for ED1, as our best view of what solutions are required to deliver improved service and enable to low carbon economy. Nevertheless, our innovation horizon expands beyond ED1 into ED2 and ED3, as all our scenarios and models are developed to look until 2050, in line with the Government's aspirations for decarbonisation of the sector and reducing greenhouse gases by 80% compared with 1990 levels.

Our scenarios forecast that only the initial part of the low carbon uptake will take place during ED1, with the majority of the growth taking place during ED2. With this insight, we have already set out our Innovation Strategy and Future Network Development Plan.

Our Future Network Development Plan (see chapter 3 for long-term innovation themes to become a DSO) covers many innovative solutions that are still in its infancy at the moment and will remain so during ED1, but have the potential to make contribution in later periods. Our Key Strategic Objectives and our processes to select and embed innovation, such as the Smart Network Plan (ED2 and Blue Sky Innovation Trays) discussed in chapter 9, are all robust and will remain valid.

We proactively continue to assess the 'future solutions' with the potential to start trialling them during late ED1 / early ED2 so we can deploy them on our networks during ED2 or ED3. This will enable UK Power Networks to be ready for the major low carbon uptake our scenarios foresee.

5.12 Confidence and risk

During the process of finalising the business plan and the Smart Grid elements included in the business plan, UK Power Networks has maintained a high-level view of the risks associated with each cost saving element being built into the plan. This risk view is shown below alongside comments.

Corresponding with comments earlier in the document, it is vital to understand that the risk here is that shouldered by UK Power Networks; the cost savings are secure for customers. Should UK Power Networks find that the savings represented by the amber or red risks below are proving to be difficult to achieve, our recourse will have to be towards efficiency savings elsewhere in the business and/or shareholder funds. Should we find that we can deliver greater savings than forecast in this document, then the additional savings will be shared with customers.

UK Power Networks feels that this is a reasonable risk profile to accept and which represents a positive outcome for our customers.

Figure 25 Risk assessment of savings

Source of savings	Risk	Comments
Savings in LV reinforcement		•Voltage issues easier to solve than thermal issues, but many occur on urban underground network which is more difficult. •Wide pallet of technologies to bring through from both our and other DNOs' portfolios (network voltage regulators, customer-side voltage regulators, smarter PV).
Saving from Demand Side Response schemes		•Priced conservatively reflecting the system operator's dominance. •Validation from aggregators and our customer database.
Savings in overhead line reinforcements		•Validation from helicoptor surveys.
Savings from Dynamic Transformer ratings		•Analysis of hours-at-risk in previous periods of high demand is very strong. •Our ability to forecast hours-at-risk into the future, under different growth scenarios, needs strengthening.
Savings from Partial Discharge monitoring of switchgear		•Certainly improves safety, some risk that deferrals cannot be achieved but nevertheless the safety risk has been managed. •Additional process improvements required to deliver on this, but within UK Power Networks' control.

6 Using models to build our smart business plan

6.1 Introduction

The previous chapters have presented the smart solutions included in the ED1 business plan and those considered for deployment in ED2 and beyond. During the second half of 2012 and first half of 2013, we have used models to test the impact and benefit of solutions to consider their suitability – and reduce uncertainty about their use. The table below presents the purposes we have used modelling for. Using different models allows us to compare approaches to the same question. We have built clear bridges between the results of our models and our actual business plan to provide confidence in our submission.

Table 11 The purpose of each model we used for our smart analysis.

Purpose	Models being used
Financing issues associated with the uncertainty in low carbon uptake	Imperial College LRE model
Creation of the core reinforcement plan	Bottom-up build by infrastructure planners using Element Energy's growth forecasts Imperial College LRE model
Smart interventions in the core reinforcement plan	Imperial College LRE model Site surveys Pricing and experience from existing IFI and LCNF projects Transform model
Uncertainty around the right time to invest in additional ICT to support Smart	Transform model

It must be understand that models will not give the full or necessarily the right answer in every case. They have been developed to allow analysis of multiple scenarios which are impractical to do by hand, bottom up, and multiple times over. The downside of models is that they cannot replicate the nuances of engineering judgement (e.g. interactions with issues at neighbouring substations) so are susceptible to deviation from reality.

6.2 Smart in UK Power Networks IC LRE model

6.2.1 Introduction

The Load Related model is the primary means by which we have automated our scenario analysis. It comprises a load flow model of the 6.6kV and/or 11kV, 22kV and/or 33kV and 132kV networks in each of our licence areas. The low voltage network is modelled by computer-generated representative networks, which have been shown to be good statistical match to the UK's actual distribution network designs. This approach has been reported in the academic literature and was recently used in a significant report published by the Energy Networks Association.[10]

The model differs from the Transform model developed under the auspices of the Smart Grid Forum in that it does not assess and 'pick' solutions based on a cost-benefit analysis within the model. This functionality is implemented for conventional solutions, on the basis that there are few options and the conventional reinforcement required (e.g. up-rating of a transformer, replacement of switchgear) is normally obvious. By contrast, a number of Smart Grid solutions may be applicable or possible solutions to any given problem. As such, the Load-Related Expenditure model documents sites where it applies conventional reinforcement, and flags these as potential candidates for Smart Grid solutions. The selection of Smart Grid solutions then takes place outside the model, and tested against the cost-benefit analyses shown against each solution in Chapter 4.

Specifically the model identifies opportunities for the following Smart Grid solutions:

- Demand Side Response
- Storage
- Dynamic Line Rating (Real Time Thermal Ratings)
- Fault Current Limiters
- Voltage regulation

For DSM, storage, DLR and FCL the model identifies opportunities to use these solutions. These opportunities are presented as a listing (including impact and cost) to be reviewed by the business.

Voltage regulation as a solution is not processed by the model. The model will present a count of voltage violations per type of violation per year. The applicability of voltage regulation will be determined using top-down assumptions by the business.

[10] 'Benefits of Advanced Smart Metering for Demand Response based Control of Distribution Networks: Summary report', Strbac et al., available at http://www.energynetworks.org

As shown in Table 5 the model has been of particular value in identifying the volumes of potential LV reinforcement that might be required. We have found that with respect to Demand Side Response, additional information known outside the model of work already in progress on the network, connections offers which have been accepted, etc. have shown up some shortfalls in the approach to identifying sites based on the model's algorithm. These elements are included in our Planning Load Estimates (PLEs) maintained by our infrastructure planners, as overlays on top of the underlying growth forecasts from Element Energy.

6.2.2 Solution parameters

The section below presents the scope, approach and parameters used by the model and the planners.

Table 12 Load Related model smart solution parameters

Solution	Scope	Approach	Parameters	Costs
Demand Side Management	Covering both load and generation led networks EHV and HV only ED1 and ED2	Flex constraining threshold up to allowed percentage	See DSR table below	See DSR table below
Storage	Covering both load and generation led networks EHV and HV only ED1 and ED2 EPN and SPN only	Flex constraining threshold up to allowed percentage	See storage table below	See storage table below
Dynamic Line Rating	Covering both load and generation led networks EHV and HV only OHL only ED1 and ED2	Identify opportunities for DLR by looking for lines that are running out of firm but with slow future growth. Utilisation has to stay below threshold for minimum years to make it applicable.	DLR headroom: 10% additional headroom above firm (Capability to test sensitivity of threshold; e.g. by also trialling 20% and 30%) Minimum years: 2 years	£50k per line
Fault Current Limiters	Covering both load and generation led networks EHV and HV only Connected to busbars & transformers, not generators ED1 and ED2 Available from 2014 onwards	Identify opportunities for FLR by looking for violations of switchgear fault level rating Create additional fault current 'headroom' (the additional fault current we can allow on that part of the system) on the system by flexing the ratings. Utilisation has to stay below threshold for minimum years to make it applicable.	Parameter (FCL headroom): 30% Parameter (Minimum years): 2 years;	£1 million (11kV and 33kV, including installation)
Voltage regulation	Covering both load and generation led networks All voltages	Analysis of voltage regulation suitability to be undertaken outside of the model on the output	Solutions determined outside the model	Solutions determined outside the model

Solution	Scope	Approach	Parameters	Costs
	ED1 and ED2	data. Analysis to be undertaken on types of violation (under voltage, over voltage, stability). Use ER P2/6 factor for wind/demand offset Parameter (min demand): [10%] summer minimum load (with max generation) as percentage of maximum load		

Table 13 Table 8 DSR parameter

DNO	DSR capacity	DSR duration	DSR availability	DSR daily availability window	DSR costs
EPN	2 MVA	2.5 hours	Seasonal (3 months)	5 hours	Setup costs: £5k DSR availability: £7.5/MWh DSR utilisation: £200/MWh Cost curve: WS3 type 2 (flat cost)
LPN	5 MVA	6 hours	Seasonal (3 months)	8 hours	
SPN	3 MVA	3.5 hours	Seasonal (3 months)	5 hours	

Table 14 Storage parameters

DNO	Maximum Storage capacity	Storage duration	Storage availability	Storage costs
EPN	6 MVA	2.5 hours	DNO names priority periods to cover N-1 outages	£1.4 m / MVA (SNS) £1.2m - £1.8m / MVA (WS3) Cost curve: WS3 type 3: $99.576e^{-0.01x}$
LPN	N/A	N/A		
SPN	6 MVA	2.5 hours		

6.2.3 Generation

Many smart solutions are considered as a response to increased penetration of low carbon generation. Traditionally, load flow modelling focussed primarily on demand. To allow the model to assess suitability of smart solutions, new low carbon generation has now been included. This section presents the approach used to incorporate this generation.

- **LV connected generation -** The growth of LV connected generation is based on the UK Power Networks business plan scenarios. The location of growth is developed by Element Energy[11], using external data such as demographics, geography, and orientation of roof profiles towards the south. The location allocation includes a degree of clustering. Generation technologies include PV and wind, and the same approach has been used across the three networks
- **HV and above connected generation** – Growth is based on UK Power Networks business plan scenarios. Included is onshore wind (the off-shore wind in our scenarios will be connected as embedded transmission which is not part of normal reinforcement expenditure forecasting)

The generation results are currently being tested and refined as part of the on-going development of the model after business plan submission.

6.3 Transform model

6.3.1 Introduction

The Transform model was designed to estimate the impact that various scenarios regarding the uptake of Low Carbon Technologies (LCTs) would have on distribution networks in Great Britain. It also facilitates analysis of investment approaches for dealing with this impact, in particular analysing the benefits that may be seen if smart technologies are considered as an alternative to traditional reinforcement of networks. The model has indicated that, at a national level, the investment required on distribution networks could be materially reduced by the use of Smart Grid solutions.

UK Power Networks have tailored three instances of the Transform model to reflect the three license areas operated: EPN, LPN and SPN. The results obtained from these tailored models have informed UK Power Networks' approach to smart solutions in the ED1 period.

[11] Using techniques similar to those adopted by SGF WS3 in creating the Transform model

6.3.2 Tailoring and testing the model

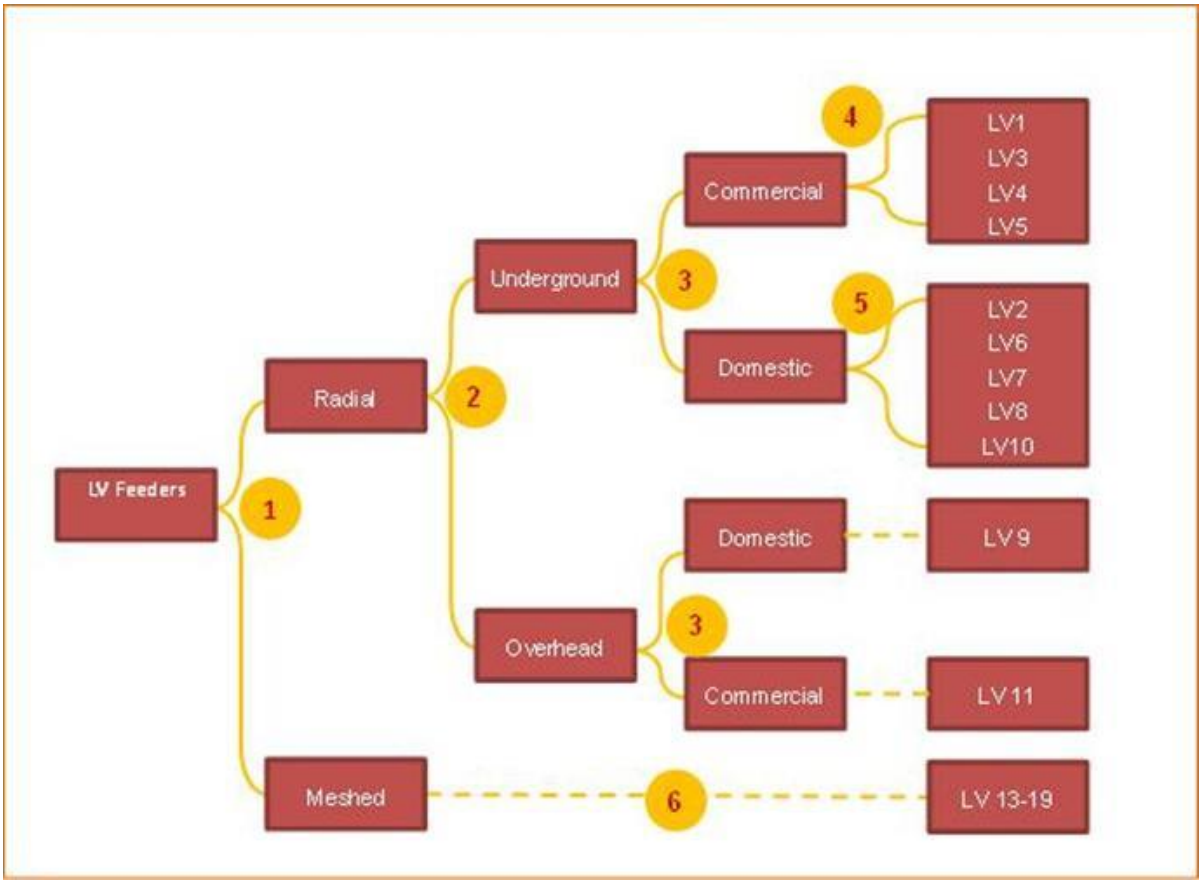
There are five steps to tailoring the model:

- Categorise feeders and determine network topology
- Correct the assignment of Low Carbon Technologies (LCTs) to feeders
- Match Maximum Demand (MD) and the number of Connected Customers to our known values
- Adjust starting capacities based on utilisation
- Voltage and fault level

Significantly, changes were only made to the configuration of the networks used to build the model. All of our model runs have used the suite of Smart Grid solutions, their costs and benefits, as originally shipped and unchanged. Our work in tailoring and testing the model was reviewed by EA Technology, the developers of the model, and who confirmed in writing the validity of our approach.

Network Topology and Details

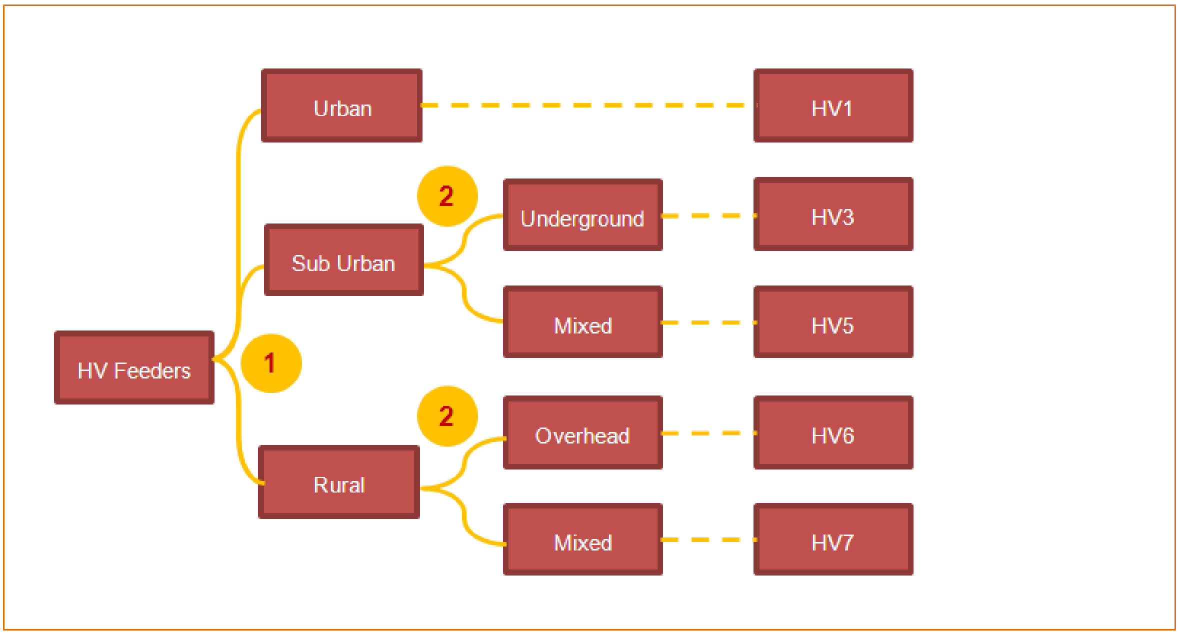
To tailor the model to represent UK Power Networks' three license areas the values that represent the topology of the network within the model first need to be updated based on the relevant network of interest. The first step in doing this was to categorise each of the feeders in the license area as they stood during the 2011/12 regulatory year into a 'feeder class' defined in the Transform model. The approach taken was to use multiple network and external data sets to which a set of rules were applied to assign a classification to each LV feeder. The decision tree for this process is shown below, in which decisions are numbered against each branch, along with the rules that were used. This process was then developed into an automatic script that was run on the data and produced the values needed.



Decision	Data Set Used	Criteria
1	Network Records for interconnected feeder groups in LPN	If HV feeder group is identified as having LV interconnection, networks categorised as meshed

Decision	Data Set Used	Criteria
2	Network Records showing lengths of overhead and underground sections on feeders	Dominant (>50%) conductor type is used to categorise
3	MPAN of connected customers commercial/domestic categories	Dominant (>50%) category defines feeder type between domestic and commercial
4	Experian data matched on first half of postcode of feeding secondary substation	Experian sector data used to determine likelihood of commercial being industrial/retail
5	Experian data matched on first half of postcode of feeding secondary substation	Experian sector data used to determine Urban/Suburban/Rural split and also housing type
6	Feeders categorised as meshed (only present in LPN) are subsequently categorised using the same criteria as for radial feeders and the corresponding meshed feeder types are used	

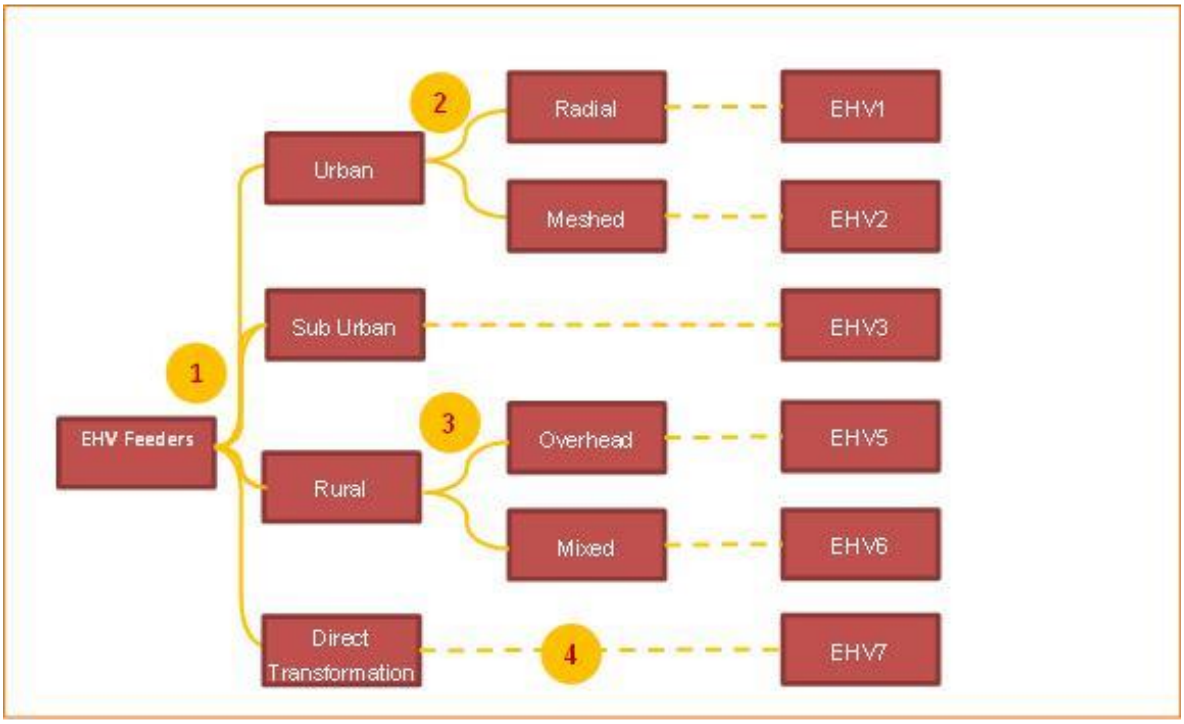
A version of this process was repeated for HV feeders. HV feeders were largely classified based on the type of LV feeders that they are connected to. This link between HV feeders and the LV feeders they supply is inherent in the data sets used so was utilised in the categorisation process. Further data was then used to determine whether the conductor was dominantly overhead, underground or mixed construction. The decision tree below describes this process which, again, was developed into an automated script.



Decision	Data Set Used	Criteria
1	HV feeders are first designated as Urban/Suburban/Rural based on the dominant type of LV feeders they supply	The dominant characteristic of the LV feeders determines the HV classification

2	Network records showing lengths of overhead and underground construction	Feeder is designated as mixed if it is not made up of greater than 80% of one type of construction.

This process was finally repeated for EHV feeders as described in the diagram below.



Decision	Data Set Used	Criteria
1	EHV feeders are first designated as Urban/Suburban/Rural based on the dominant type of HV feeders they supply	The dominant characteristic of the HV feeders determines the EHV classification
2	Network Records showing topology of feeders/substations	Feeders were considered meshed if they were electrically connected to another feeder of the same voltage level under normal running conditions
3	Network records showing lengths of overhead and underground construction	Feeder is designated as mixed if it is not made up of greater than 80% of one type of construction.
4	Network data showing primary and secondary voltages of substations	If a substation had a primary voltage of 132kV and a secondary voltage of 11kV

Once all feeders, at all voltage levels, have been classified the necessary numbers to populate the model can be calculated. The number of networks classified into each class and the connectivity present in the original data sets was used to derive the percentages that represent how networks are connected. This process validates itself by producing the correct number of LV feeders (known from the original data) once the model runs through the connectivity implied in the percentages provided.

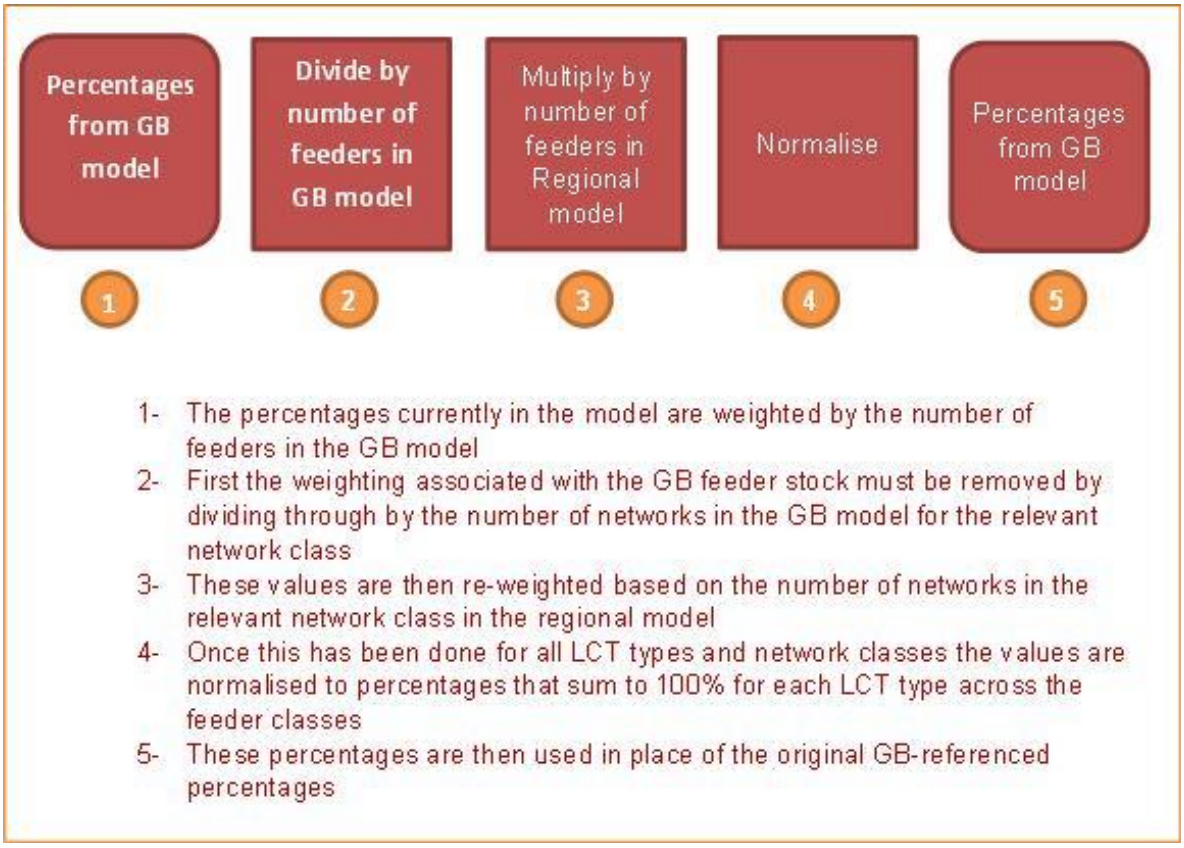
Correcting the Low Carbon Technology (LCT) assignment to feeders

The default Low Carbon Technology (LCT) assignment within the regional model is based on the proportions of different types of feeders in the GB model (the 'feeder stock'). Since the feeder stock of the individual license areas will be proportionally different this means that:

- LCTs may be assigned to feeder classes that have not been used in a regional instance of the model. This would lead to these LCTs not being taken into account in the model

- Large amounts of LCTs may be assigned to a network class that only has a small number of feeders assigned to it because that particular feeder class had a large amount of feeders in the GB model. This would lead to the small number of feeders in the regional model being burdened with a large amount of LCT load and requiring reinforcement erroneously

To ensure the above anomalies are not produced by the regional model the LCT allocation was adjusted to be proportional to the number of feeders in each class on a license area basis. The process to achieve this is described below.



Match Maximum Network Demand and Number of Connected Customers

Using the inputs described above, the model is run and the Maximum Demand (MD) of the whole network and the number of customers connected to it based on the inputs are observed. This observation then triggers a process of iteration which seeks to ensure that these two numbers match our known values. Differences between the modelled number of customers and the known value are corrected by adjusting the number of customers connected to each feeder while keeping the proportions of types of customer constant. To correct for differences in maximum demand the multiplier between LV connected commercial load and HV commercial load is adjusted as advised by EA Technology.

Starting Capacities

The original guidance from EA Technology regarding Starting Capacities was that they should be adjusted to ensure that the investment in the first year of modelled output was not anomalous. However, the provision of Advanced Outputs from the model gave visibility of how the starting capacities were affecting investment outputs produced by the model. This functionality showed that the investment was concentrated on a few network classes due to inconsistencies between how load is assigned in the model and the starting capacities based on network records data.

Users have little control over how load is assigned to different feeder classes within the model; this is driven by the load assignments provided by Element Energy. Once a user has categorised the feeders on a network there may be a mismatch between the philosophy behind the assignment of load and the way in which the feeders have been categorised. Since reinforcement is a product of both these parameters it can be influenced by the mismatch and produce non-intuitive results.

To improve the investment profile across feeder classes the starting capacities were adjusted to reflect the maximum load that is seen on each feeder class based on the load assignment within the model. Asset ratings and historical maximum demand readings were used to calculate an average utilisation of LV networks at a distribution substation level for each license area. Using the known average utilisation of LV networks (50%-60% depending on license area); the starting capacities were adjusted to produce a more realistic utilisation within the model to ensure that the need for investment identified by the model is better informed.

To take account of the fact that the model is not capable of representing the utilisation profile within a feeder class (the fact that some networks will be more highly utilised than others; they are not all average), the starting capacities were scaled down using factors within the model. In addition to this, some network classes were identified as being more likely to be less thermally constrained and the starting capacities were adjusted to reflect this fact.

Specific Alterations

Certain results from the model were identified as unreliable and further investigation into the drivers behind them was undertaken. This led to the following two specific changes to the inputs of the model:

- The nominal voltage of rural HV feeders was adjusted from being at the midpoint of the voltage limits to being closer to the upper limit. This is consistent with the idea that the feeder would be operated at a higher voltage at the substation end to take account of voltage drop along characteristically long lines
- The fault level headroom was reduced for HV feeders in the LPN area to reflect the fact that fault levels tend to be higher in this area (dense network, direct transformation) and this may preclude certain solutions to other headroom violations

Solution Parameters

All solution parameters remain unchanged from those provided with the model by the members of Work Stream 3 of the Smart Grid Forum.

6.3.3 General commentary on transform model smart solutions

The Transform Model categorises networks into a limited set of network types. When analysing which solutions to apply to a particular network constraint the model will treat all networks in a particular category (and cluster group) identically. This often leads to large numbers of networks being reinforced at the same time creating large spikes in investment. This behaviour is more apparent when looking at results over a short period of time as there is less opportunity for such peaks to average out. This can cause misleading results as even small changes to inputs or the period over which results are analysed can have large impacts on levels of investment. In reality, assets on the network will have differing levels of utilisation meaning there is a profile of utilisation within each category of network that would mean such spike would not be generated.

A secondary effect of this behaviour becomes apparent when the model is considering smart solutions to network constraints. If a smart solution is identified as the most cost effective solution in any particular case, this solution will be applied to a large amount of feeders regardless of their individual suitability for a solution. This is exacerbated in LPN where the similarity of the network (all underground, no rural etc.) means that there are a large number of feeders in each category. This may lead to an overestimation of the benefits that could be seen by applying any particular solution since the most cost effective solution is applied universally where the reality may be that a variety of solutions with varying cost effectiveness would be suitable. This also means the suite of solutions suggested by the model may lack variety and heavily favour certain solutions.

The task 3.6 report of work stream 3 of the Smart Grid Forum refers to the behaviour above highlighting the fact that if prevalent solutions are made unavailable the overall benefit from smart solutions does not change significantly since other solutions can be deployed to replace it. The conclusion from this is that the model is better used to indicate the benefits of a particular investment strategy rather than a tool for choosing particular solutions.

6.4 Reconciliation of smart solutions for ED1

6.4.1 Introduction

In the previous sections, we introduced the two main models we have used to inform our ED1 business plan and provide our outlook into ED2 – the latter to ensure that we can choose the long-term best options.

Both our business plan and the Transform model follow a 'smart incremental' approach in which Smart Grid solutions are selected and installed site-by-site as the need arises, and the enabling technologies are built out at the same rate. As such, we present in this section direct comparisons between our submitted business plan and the Transform model.

6.4.2 Building a comparable plan using the Transform model

When comparing two strategies (BAU vs. incremental smart) for five scenarios (4 DECC scenarios and UKPN's own 'best view' scenario) for our three different network (EPN, LPN and SPN), the amount of information and how they compare to one another becomes difficult to present.

For the reader's benefit, we have developed visual bridges which aim to capture in one place a simple view of how our business plan compares to Transform and the various Transform scenarios; the impact of BAU vs. Smart and how that difference is achieved (bridged).

With the three bridges we present in this section, we analyse the difference between the Transform model 'BAU' and 'Smart Incremental' outcome and the main smart solutions that drive the difference.

Transform typically highlights four to six savings which bring the most net benefits. We present those explicitly in the bridge and we discuss our views on current suitability for UKPN. When assessing this suitability, we consider the coincidence of geographic and network conditions (e.g. the right opportunity at the right location to make use of the solution) and the technology maturity (e.g. we may consider a technology not sufficiently mature to commit to at this moment, but will start trials to further understand its impact).

We also assess potential deployment difficulties and which technologies might give us a more certainty of delivering benefits at this point in time. As examples, Time-of-Use tariffs require a supplier contact; if Photovoltaics are to provide reactive power support it may require support through government policy and standards. These are both examples of solutions outside our direct control. In placing our 'bets' in the £141 million we have concentrated on substation solutions we can guarantee to deliver, but are open to ToU tariffs for example to make up part of our DSR total, and will actively be innovated in ED1 and watching other DNOs' projects on non-substation solutions.

On the latter half of the bridge we build up a comparable NAMP – meaning we use the Transform model 'Incremental Smart' outcome as a base for our NAMP instead of our LRE/PLE process.

To build up the NAMP, we need to add two cost categories:

- **132kV investments** – this voltage level is used by us but not included in the March 2014 Transform Model. The value we add here is the same as we have in our business plan.
- **Diversions** - additional costs which the model cannot foresee, such as National Grid requirements, the need for tunnels or alternative routes due to local geographic constraints (e.g. planning permission)

The final part of the bridge, on the right, is our Comparable NAMP based on the transform model (for load related expenditure). We use this Comparable NAMP in the next bridge, were we compare this outcome to all Transform model scenarios.

Please note that the financial figures in these bridges do not represent the full costs to the business, such as the engineering effort, labour and contractors (indirect costs) associated with doing capital works. These bridges present the most impacted part – the Capital Expenditure (equipment we have to buy). Accompanying our June 2013 business plan submission, full costs were worked up in our submission for our own 'best view' scenario' and for a 'reference' case (based on DECC Scenario 1, High abatement in Low Carbon heat scenario) for easy comparison across all DNOs. We have provided submissions based on both the Transform model total reinforcement forecasts and the Imperial Load-Related Expenditure (LRE) model total reinforcement forecasts.

6.4.2.1 EPN Bridge

For EPN, the Transform model calculates a reinforcement cost of £170 million for BAU during ED1 to cater for the forecasted increase in network demand. By deploying smart solutions the cost reduces by £37 million to £133 million.

The main contributors to this difference are:

- LV Meshing (Both) £9 million
- HV Switched Caps £9 million
- HV Temp Meshing £8 million

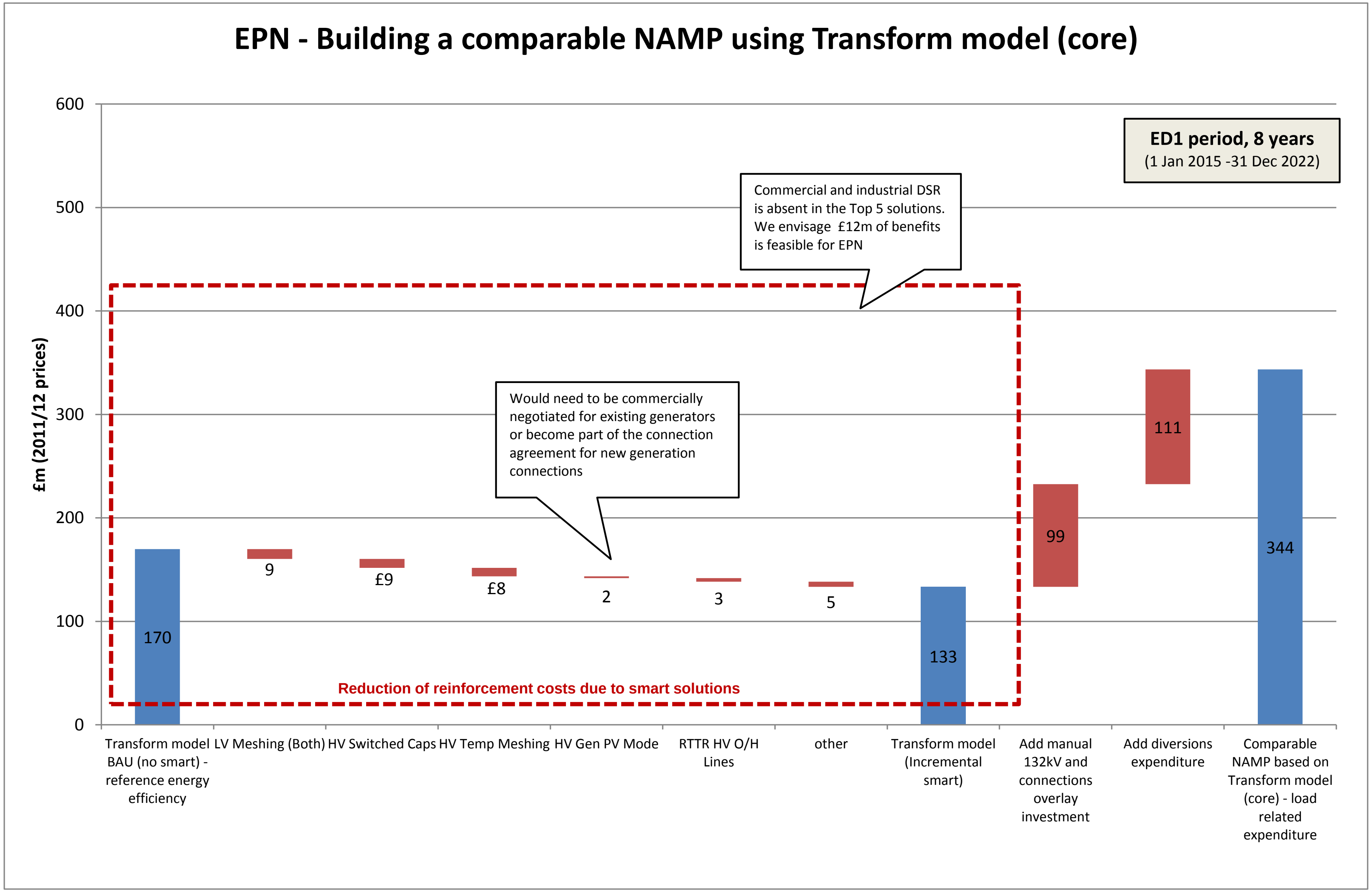
- HV Gen PV Mode £2 million
- RTTR HV O/H Lines £3 million

LV meshing, HV switched capacitors and Real Time Thermal Rating for overhead lines are all either already being included in our plans or are still under consideration. HV temporarily meshing is also a viable option if geographic conditions and network conditions allow this to be deployed.

We see less applicability of the solution ‘Generator providing Network Support e.g. operating in PV mode at HV’, as this would need to be commercially negotiated for existing generators or become part of the connection agreement for new generation connections.

We note that commercial and industrial DSR is absent in the Top 5 solutions of the Transform model. Our own analysis envisage £12 million of benefits is feasible for EPN

Finally, to build up our Comparable NAMP for EPN based on the Transform model, needed for comparison in the bridges in the next section, is derived by adding 132kV and diversions results in a comparable NAMP of £344m. The cost category diversions is relatively high in EPN, as in SPN, due the higher proportion of overhead lines, which results in more requests to divert the routes, e.g. when crossing nature reserves or specific public places.



EPN - Building a comparable NAMP using Transform model (core)
ED1 period, 8 years
(1 Jan 2015 -31 Dec 2022)
Commercial and industrial DSR is absent in the Top 5 solutions. We envisage £12m of benefits is feasible for EPN
Would need to be commercially negotiated for existing generators or become part of the connection agreement for new generation connections
£m (2011/12 prices)
600
500
400
300
200
100
0
170
9
£9
£8
2
3
5
133
99
111
344
Reduction of reinforcement costs due to smart solutions
Transform model BAU (no smart) - reference energy efficiency
LV Meshing (Both)
HV Switched Caps
HV Temp Meshing
HV Gen PV Mode
RTTR HV O/H Lines
other
Transform model (Incremental smart)
Add manual 132kV and connections overlay investment
Add diversions expenditure
Comparable NAMP based on Transform model (core) - load related expenditure

6.4.2.2 LPN Bridge

For LPN, the Transform model calculates a reinforcement cost of £127 million for BAU during ED1 to cater for the forecasted increase in network demand. By deploying smart solutions the cost reduces by £20 million to £108 million.

Originally the output from the model for the LPN area is suggesting that there would be a significant benefit from meshing HV networks. We discussed in detail in Section 3.2 the extent to which meshing is already in place in LPN. In order to recognise the level of meshing already in place, we disabled this option. The impact of this change turns out the be minimal; the benefits that were previously attributed to HV meshing are instead provided by other HV smart solutions, such as HV D-FACTS.Electronics at HV level.

The main contributors to this difference are:

- HV DFACTS £15 million
- LV Mesh (Mostly Urban) £1 million
- LV Switched Caps £3 million

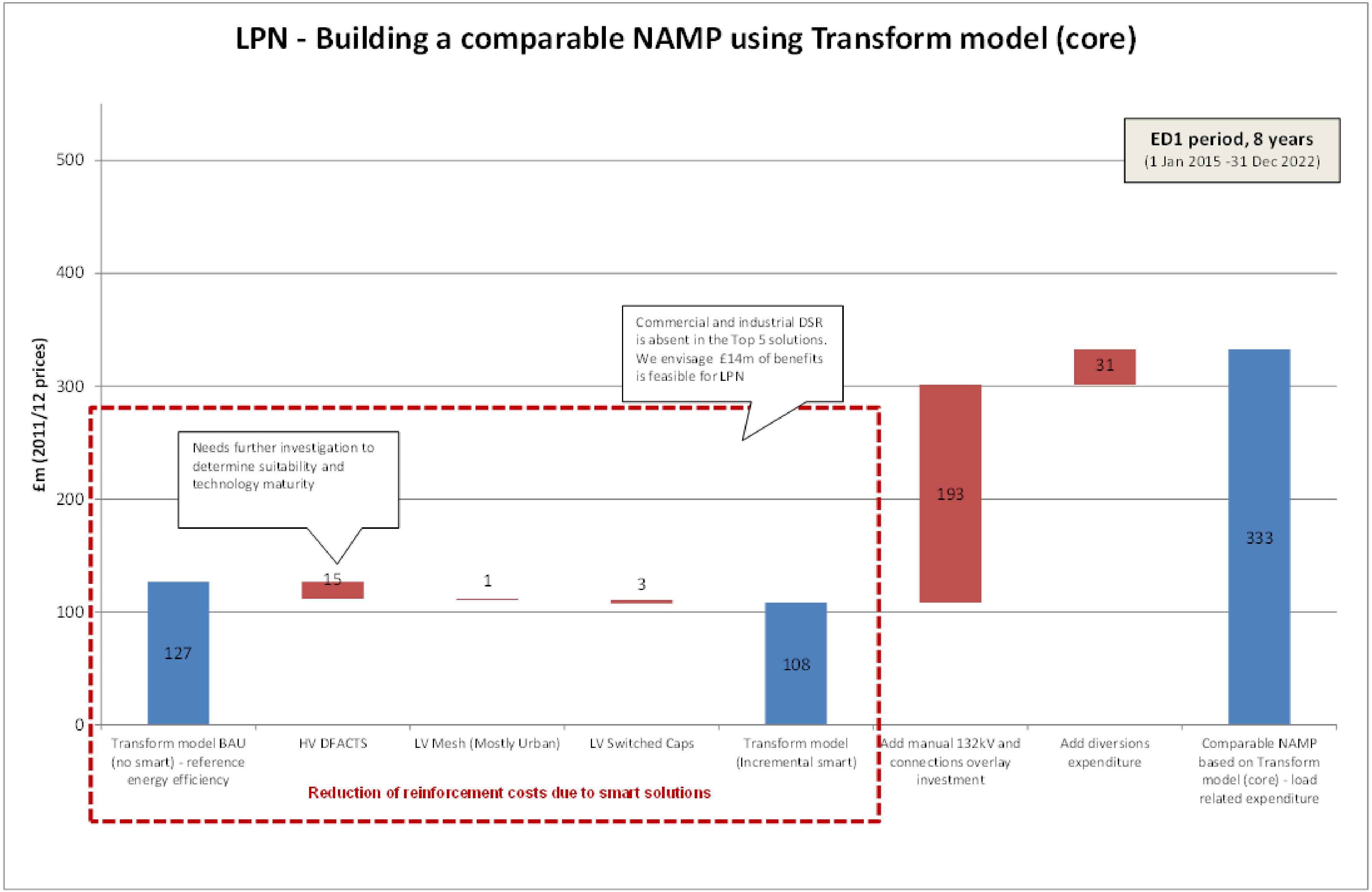
UKPN considers HV DFACTS a viable option, but needs further testing before we can commit to deployment at this stage. We are developing a Low Carbon Network Fund Bid to test HV power Electronics at HV level in the LPN and SPN networks. The bid has successfully passed the Initial Screening Process and we are now developing the full bid.

LV meshing is being considered where suitable and is now the subject of a Low Carbon Network Fund Tier-2 project awarded to UK Power Networks in November 2013.

Capacitors at LV have recently come to the fore as part of the response in the United States to the opportunity presented by Conservation Voltage Reduction (CVR). Under a CVR programme, the voltage set-point of the network is reduced; a consequence is that long rural overhead feeders need reactive power support, which capacitors can provide. At this stage, we believe that more work is required to understand the applicability of Conservation Voltage Reduction to the UK which has more aggressive targets for the uptake of LCTs than the US, and which will expect greater stress on voltage regulation schemes.

We note that commercial and industrial DSR is absent in the Top 5 solutions of the Transform model. Our own analysis envisage £13.9 million of benefits is feasible for LPN.

Finally, to build up our Comparable NAMP for LPN based on the Transform model, needed for comparison in the bridges in the next section, is derived by adding 132kV (this cost category is higher in London due to typical costs of works both in substations and cable routes) and diversions (relatively low as most of the network is underground) results in a comparable NAMP of £333 million.



LPN - Building a comparable NAMP using Transform model (core)
ED1 period, 8 years
(1 Jan 2015 -31 Dec 2022)
£m (2011/12 prices)
500
400
300
200
100
0
Commercial and industrial DSR is absent in the Top 5 solutions. We envisage £14m of benefits is feasible for LPN
Needs further investigation to determine suitability and technology maturity
127
15
1
3
108
193
31
333
Transform model BAU (no smart) - reference energy efficiency
HV DFACTS
LV Mesh (Mostly Urban)
LV Switched Caps
Transform model (Incremental smart)
Add manual 132kV and connections overlay investment
Add diversions expenditure
Comparable NAMP based on Transform model (core) - load related expenditure
Reduction of reinforcement costs due to smart solutions

6.4.2.3 SPN Bridge

For SPN, the Transform model calculates a reinforcement cost of £135 million for BAU during ED1 to cater for the forecasted increase in network demand. By deploying smart solutions the cost reduces by £45 million to £90 million.

The main contributors to this difference are:

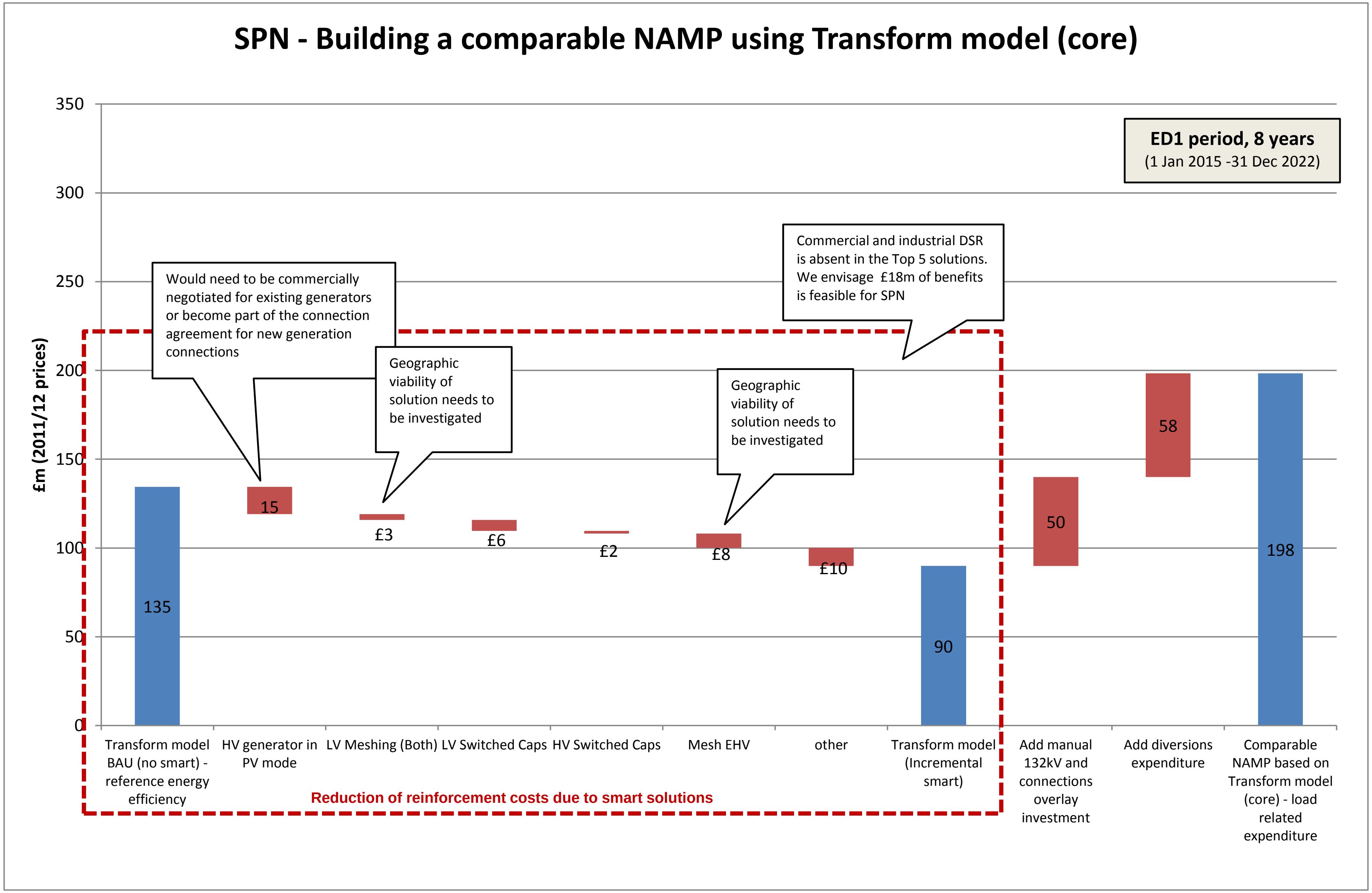
• HV generator in PV mode	• £15 million
• LV Meshing (Both)	• £3 million
• LV Switched Caps	• £6 million
• HV Switched Caps	• £2 million
• Mesh EHV	• £8 million

HV switched capacitors is still under consideration. EHV and similarly LV meshing are both viable options if geographic conditions and network conditions allow this to be deployed.

As in EPN, we see less applicability of the solution 'Generator providing Network Support e.g. operating in PV mode at HV', as this would need to be commercially negotiated for existing generators or become part of the connection agreement for new generation connections. For LV switched capacitors, just as in LPN, we await further outcomes from the USA based Conservation Voltage Reduction trials before committing to this technology.

We note that commercial and industrial DSR is absent in the Top 5 solutions of the Transform model. Our own analysis envisages £18m of benefits is feasible for SPN.

Finally, to build up our Comparable NAMP for SPN based on the Transform model, needed for comparison in the bridges in the next section, is derived by adding 132kV and diversions results in a comparable NAMP of £198m. The cost category diversions is relatively high in SPN, as in EPN, due the higher proportion of overhead lines, which results in more requests to divert the routes, e.g. when crossing nature reserves or specific public places.



SPN - Building a comparable NAMP using Transform model (core)
£m (2011/12 prices)
350
300
250
200
150
100
50
0
ED1 period, 8 years
(1 Jan 2015 -31 Dec 2022)
Would need to be commercially negotiated for existing generators or become part of the connection agreement for new generation connections
Geographic viability of solution needs to be investigated
Geographic viability of solution needs to be investigated
Commercial and industrial DSR is absent in the Top 5 solutions. We envisage £18m of benefits is feasible for SPN
135
15
£3
£6
£2
£8
£10
90
50
58
198
Transform model BAU (no smart) - reference energy efficiency
HV generator in PV mode
LV Meshing (Both)
LV Switched Caps
HV Switched Caps
Mesh EHV
other
Transform model (Incremental smart)
Add manual 132kV and connections overlay investment
Add diversions expenditure
Comparable NAMP based on Transform model (core) - load related expenditure
Reduction of reinforcement costs due to smart solutions

6.4.3 How our Core NAMP compares to transform model outcomes

These three bridges present the savings we achieve in our submitted business plans for our three networks by using the smart solutions we have committed to deploy, how these smart business plans compares to the Transform model and finally how our 'Best View' (UK Power Networks Core) compares to the 4 DECC scenarios.

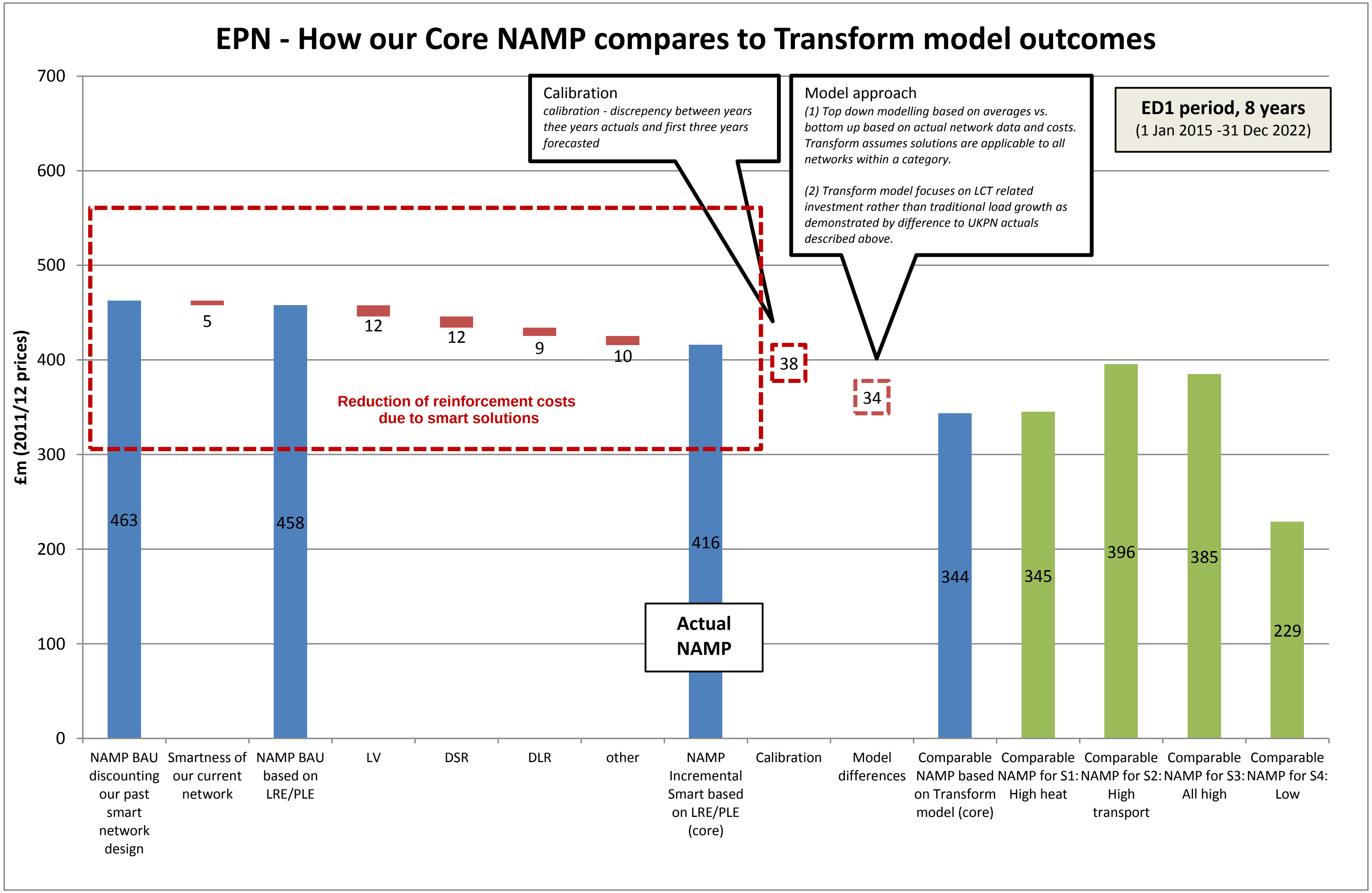
The bridge is built up as follows:

- BAU Business plan discounted our previous smart network planning – We have very sound track record of applying innovative solutions to networks in the past. For an accurate comparison of the total savings of smart of our network, we have calculated what the value of these previous solutions would be, so we can determine how much expenditure would be required for ED1 if our network was completely stripped of smart solutions and built purely by traditional reinforcements. This was discussed in more detail in Section 3.2.
- NAMP BAU based on LRE/PLE - The total expenditure we would need during ED1 starting from our current network with a certain level of past smartness already included, and following a review of all load-related and condition related expenditure during Q1 2014.
- Smart solutions - The savings of the smart solutions we have selected as those delivering best value for money to the customers
- NAMP Incremental Smart based on LRE/PLE – Our business plan as submitted based on the LRE model, Planning Load Estimates and local engineering insight
- Comparable NAMP based on Transform model (core) – Our business plan to deliver our core 'best view' scenario, based on Transform model, as calculate above. The difference between our submitted business plan and comparable business plan is illustrated and explained by the dotted lines and commentary
- Comparable NAMP for different scenario runs – Same comparable business plans, but now to deliver the four DECC scenarios
- As in the previous section, the costs presented below are the forecasted capital expenditure need, not the full cost to the business

6.4.3.1 EPN Bridge

For EPN, our LRE/PLE forecasting approach calculates a reinforcement cost of £463 million for BAU. That is inclusive of the saving of previously smart network planning, estimated to be £5 million. The use of smart solutions reduces the cost by £42 million to £416 million. With a comparable NAMP of £344 million, our 'best view' (core) sits close to the higher of the DECC scenarios.

The difference between the NAMP based on our LRE/PRE approach and the based on Transform model is £72 million, roughly equally shared between our estimations of the impact of calibration discrepancies and differences in modelling approach.

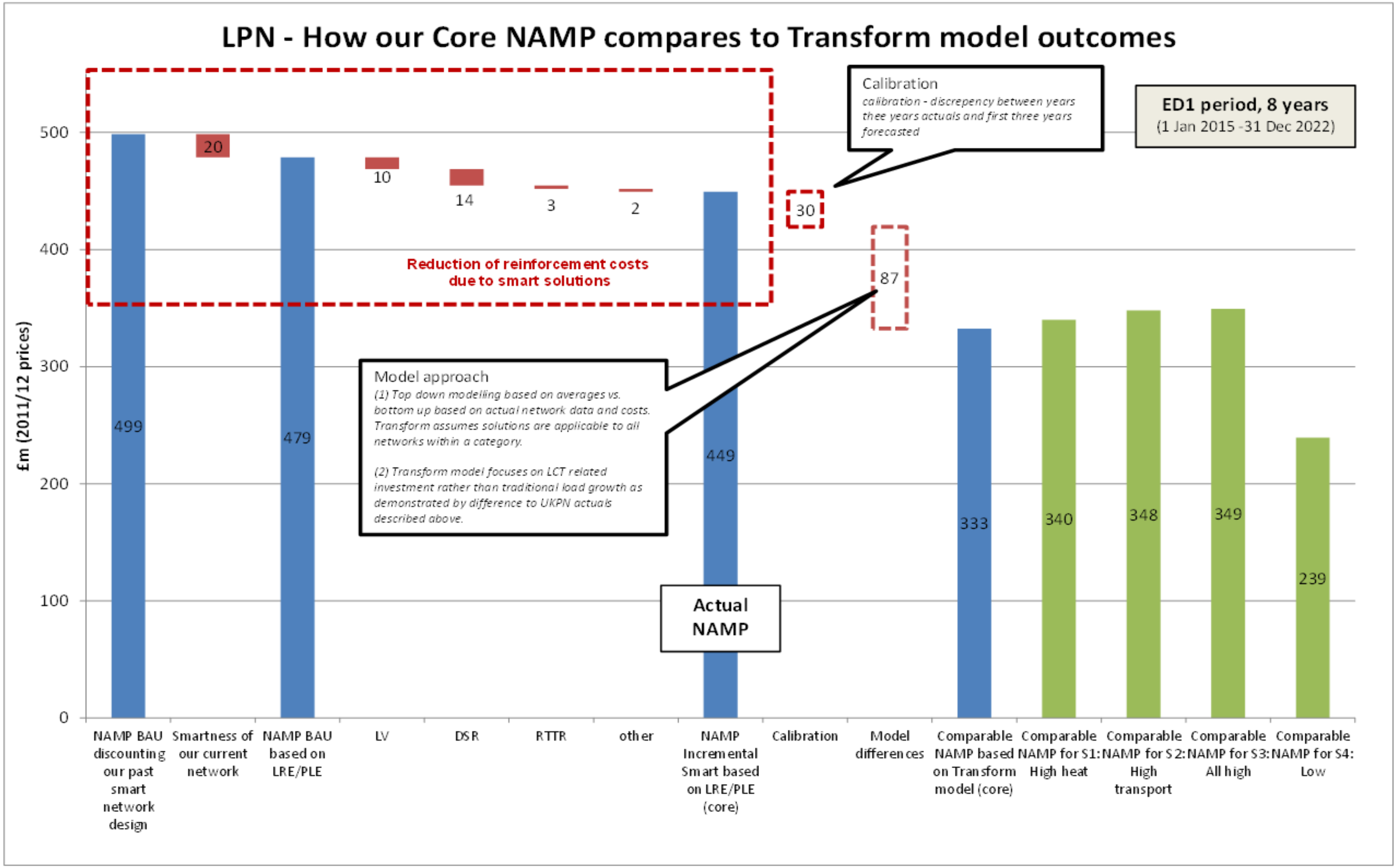


EPN - How our Core NAMP compares to Transform model outcomes
£m (2011/12 prices)
700
600
500
400
300
200
100
0
Calibration
calibration - discrepency between years thee years actuals and first three years forecasted
Model approach
(1) Top down modelling based on averages vs. bottom up based on actual network data and costs. Transform assumes solutions are applicable to all networks within a category.
(2) Transform model focuses on LCT related investment rather than traditional load growth as demonstrated by difference to UKPN actuals described above.
ED1 period, 8 years
(1 Jan 2015 -31 Dec 2022)
Reduction of reinforcement costs due to smart solutions
Actual NAMP
463
5
458
12
12
9
10
416
38
34
344
345
396
385
229
NAMP BAU discounting our past smart network design
Smartness of our current network
NAMP BAU based on LRE/PLE
LV
DSR
DLR
other
NAMP Incremental Smart based on LRE/PLE (core)
Calibration
Model differences
Comparable NAMP based on Transform model (core)
Comparable NAMP for S1: High heat
Comparable NAMP for S2: High transport
Comparable NAMP for S3: All high
Comparable NAMP for S4: Low

6.4.3.2 LPN Bridge

For LPN, our LRE/PLE forecasting approach calculates a reinforcement cost of £499m for BAU. That is inclusive of the saving of previously smart network planning, estimated to be £20 million. The use of smart solutions reduces the cost by £29 million to £449 million.

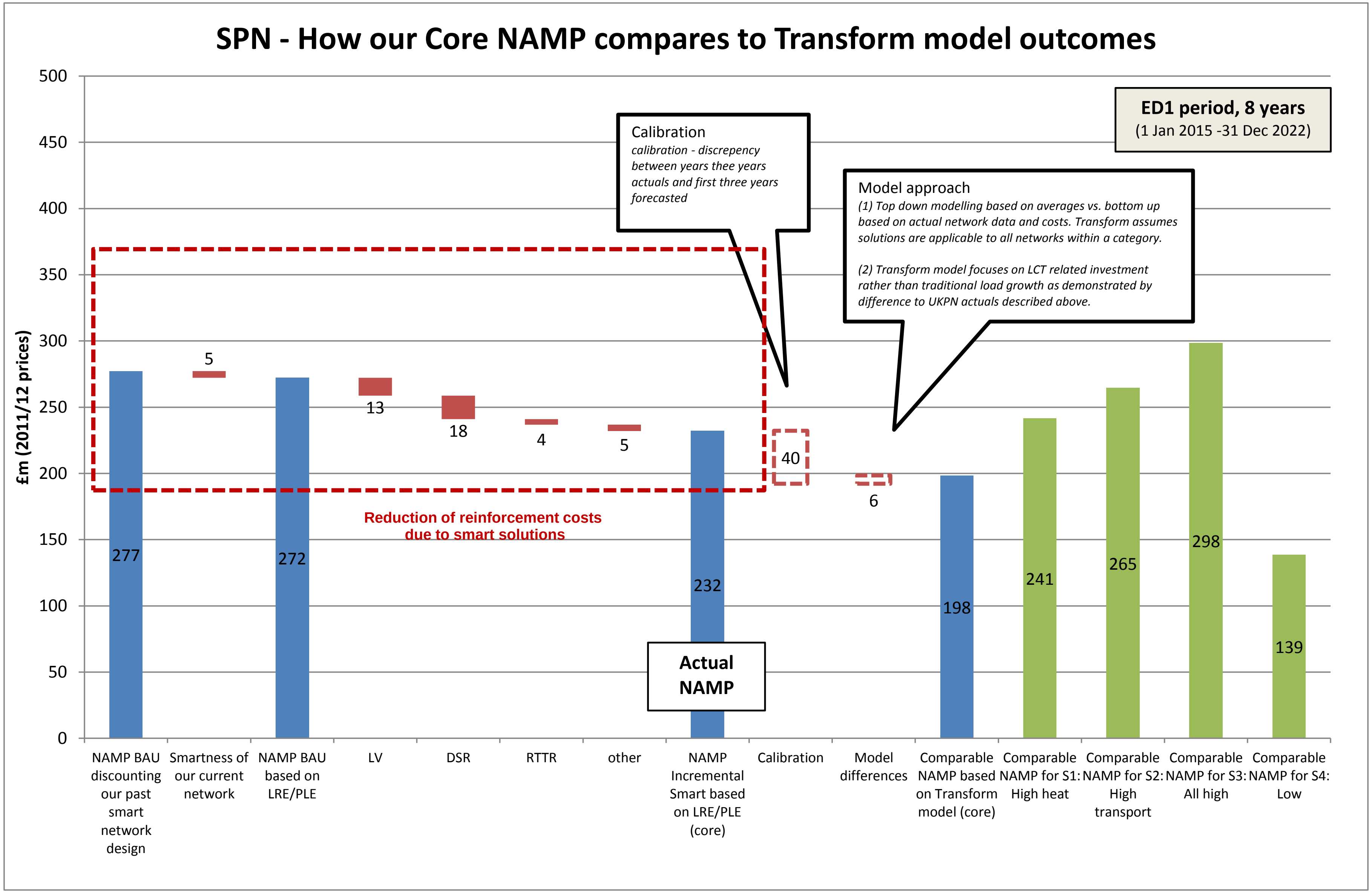
The difference between the NAMP based on our LRE/PRE approach and the based on Transform model is £117 million, mainly driven by the impact of modelling differences as the Transform model is less suitable to model the complex and dense interconnected network of LPN, as described earlier.


LPN - How our Core NAMP compares to Transform model outcomes
£m (2011/12 prices)
500
400
300
200
100
0
Calibration
calibration - discrepency between years thee years actuals and first three years forecasted
ED1 period, 8 years
(1 Jan 2015 -31 Dec 2022)
Reduction of reinforcement costs due to smart solutions
Model approach
(1) Top down modelling based on averages vs. bottom up based on actual network data and costs. Transform assumes solutions are applicable to all networks within a category.
(2) Transform model focuses on LCT related investment rather than traditional load growth as demonstrated by difference to UKPN actuals described above.
Actual NAMP
499
20
479
10
14
3
2
449
30
87
333
340
348
349
239
NAMP BAU discounting our past smart network design
Smartness of our current network
NAMP BAU based on LRE/PLE
LV
DSR
RTTR
other
NAMP Incremental Smart based on LRE/PLE (core)
Calibration
Model differences
Comparable NAMP based on Transform model (core)
Comparable NAMP for S1: High heat
Comparable NAMP for S2: High transport
Comparable NAMP for S3: All high
Comparable NAMP for S4: Low

6.4.3.3 SPN Bridge

For SPN, our LRE/PLE forecasting approach calculates a reinforcement cost of £277 million for BAU. That is inclusive of the saving of previously smart network planning, estimated to be £5 million. The use of smart solutions reduces the cost by £40 million to £232 million. With a comparable NAMP of £198 million, our 'best view' (core) sits within the bars representing the various DECC scenarios on an equivalent basis.

The difference between the NAMP based on our LRE/PRE approach and the based on Transform model is £34 million, is mainly driven by impact of calibration discrepancies between our two models for the first years.


SPN - How our Core NAMP compares to Transform model outcomes
£m (2011/12 prices)
ED1 period, 8 years
(1 Jan 2015 -31 Dec 2022)
Calibration
calibration - discrepency between years thee years actuals and first three years forecasted
Model approach
(1) Top down modelling based on averages vs. bottom up based on actual network data and costs. Transform assumes solutions are applicable to all networks within a category.
(2) Transform model focuses on LCT related investment rather than traditional load growth as demonstrated by difference to UKPN actuals described above.
Reduction of reinforcement costs due to smart solutions
Actual NAMP
277
5
272
13
18
4
5
232
40
6
198
241
265
298
139
NAMP BAU discounting our past smart network design
Smartness of our current network
NAMP BAU based on LRE/PLE
LV
DSR
RTTR
other
NAMP Incremental Smart based on LRE/PLE (core)
Calibration
Model differences
Comparable NAMP based on Transform model (core)
Comparable NAMP for S1: High heat
Comparable NAMP for S2: High transport
Comparable NAMP for S3: All high
Comparable NAMP for S4: Low

6.4.4 Conclusions

In this chapter we have presented how we have used different models to assess the potential benefits of using smart solutions. These models have given us a critical new capability to model multiple scenarios of the future. By openly comparing our own analysis and forecasts with the Transform model, we have been able to test and challenge our assumptions which ultimately have given us the confidence to commit to £141 million savings from smart on capital expenditure during ED1 for our ‘best view’ scenario.

Table 5 in section 5.2 provides the overview which technologies are included in this saving, which model was used to which part of the assessment and where the detail of our financial forecast can be found in the regulatory tables. For the benefit of the reader, the bridges present this data on a higher-level visual way to better understand the relative impact of the different solutions per network.

7 Summary of smart solutions

7.1 Introduction

Chapters 5 focussed on the particular Smart Grid solutions which are built into our RIIO ED1 business plan and provided comparisons from our total investment forecasts to the Transform model. This final chapter provides a cross-reference for those readers wishing to see a summary of UK Power Networks' current of each of the Smart Grid solutions capable of being modelled by the Transform model.

7.2 Assessment of all solutions

Representative Solution	Description	Variant	UK Power Networks' view
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	We are increasing our capability to sectionalise the HV network with the aim of delivering increased quality of supply. The same technologies could be used for pro-active movement of open points if proven to be a material lever for deferring reinforcement. We are exploring these concepts for LV within our Smart Urban LV Networks Tier 1 project.
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	Our energy storage device on our Norfolk network provides STATCOM functionality and we are actively trialling the reactive power support elements in isolation from the storage and export of real power.

Representative Solution	Description	Variant	UK Power Networks' view
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	Concept being trialled in our Low Carbon London LCNF. We have located sites where DSR is suitable in our business plan for ED1. We expect a part of this response to come from residential customers equipped with Smart Meters.
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	Our Smarter Network Storage project is intending to demonstrate storage at HV and EHV as a cost-competitive solution, but which provides wider benefit across the energy sector than conventional reinforcement which serves only the DNO. On this basis, it has not contributed to the £141 million net saving within our investment forecast. We continue to watch the DNOs' trials of storage at LV with interest, but do not believe that the business case and marketing model for residential storage has been proven.
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	We do not believe DC networks for EHV and HV will be applicable during ED1 or ED2; we are observing developments on LV via other DNOs activities.
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	We have performed a number of successful trials in the context of supporting generation on HV circuits and are embedding these into business-as-usual. HV/LV Transformer Voltage Control forms part of our 'ED1 innovation tray' to be investigated.
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 are part of our SNP embedding process and we would expect to be

Representative Solution	Description	Variant	UK Power Networks' view
		HV Non-superconducting fault current limiters HV Superconducting fault current limiters	able to offer these to support generation connections, subject to their price. We consider the applicability of the other variants as lower.
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	We already actively use HV connected generation constraint as part of our BAU design. EHV is being investigated by our SNP embedding process.
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	We keep a watching brief on these technologies via other DNOs' trials.
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)	HV connected LV connected	For HV part of our SNP process. For LV we consider operation out of our control, definitely during ED1
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	We will evaluate new technologies as and when they become apparent and we keep a watching brief on these technologies via our 'Other DNOs' and National Grid innovation tray'
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	We will continue to invest in maintaining the integrity of LV-interconnected HV networks in LPN's central area where high network utilisation and no-break supplies are particularly beneficial. Meanwhile additional interconnection between EHV networks and EHV/HV substations will be applied where economically justified
Real Time Thermal Rating	Increases to circuit or asset rating through the use of real-time ambient temperature changes and local weather conditions.	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	RTTR for EHV/HV transformers and EHV Overhead Lines are lined up for our SNP embedding process. RTTR for EHV Underground Cables is part of our 'ED1 innovation tray'
Switched Capacitors	Mechanically switched devices as a form of reactive power compensation. They are used for voltage control and network stabilisation under heavy load	EHV HV LV	HV switched capacitors are already part of our BAU design processes.

Representative Solution	Description	Variant	UK Power Networks' view
	conditions.		
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	We favour solutions which at least maintain current levels of QoS particularly in CBDs. ANM solutions which improve load sharing such as LV remote control will be selectively applied and new technologies such as soft open points will be trialled at HV and possibly LV under our R&D portfolio.

8 Appendices

A.1 Overview of ED1 deliverables

(See next page).

Table 15 ED1 Deliverables Overview

ED1 deliverable	Timing	Capability requirements	Network Application	Methodology	Known as in WS3 model	Business / Technology Readiness Level	Formal TRL level	Innovation tray	Resilience to different economic and low carbon scenarios (15 = highly resilient; 0 = highly sensitive)
Enhanced network flexibility and interoperability	2021-2023	Secondary SCADA	Telecontrol of 11kV network (report by exception)	Installing RTUs in Secondary (11kV,6.6kV) substations connected to the NMS	HV/LV Tx Monitoring	Available now	TRL 9 Actual Technology qualified through successful mission operations.	Business as Usual (BAU)	8
Enhanced network flexibility and interoperability	2021-2023	Mesh radio (WAN / LAN)	SCADA / Smart Grid	SCADA comms	Comms FABRIC	New systems becoming available, unproven	TRL 6 Technology model or prototype demonstration in a relevant environment.	ED1 innovation tray	8
Enhanced network flexibility and interoperability	2021-2023	Control room / asset management visualisation tools	Condition / Duty monitoring and management	Monitor in real time the condition / duty of major assets such as transformers, switchgear etc.	Advanced control systems	Under development	TRL 7 Technology prototype demonstration in an operational environment.	Smart Network Plan (SNP)	10

ED1 deliverable	Timing	Capability requirements	Network Application	Methodology	Known as in WS3 model	Business / Technology Readiness Level	Formal TRL level	Innovation tray	Resilience to different economic and low carbon scenarios (15 = highly resilient; 0 = highly sensitive)
Enhanced system integrity	2021-2023	State estimation	Identifying voltage excursions and thermal constraints Identifying feeder re-arrangements or NOP re-arrangements to optimise load	Primary and secondary s/s monitoring Stored in data historian (e.g. OsiSoft PI) Combined with network model State estimation algorithm runs within load flow tools or (potentially) post-calculates and populates additional 'virtual' data points in OsiSoft PI	HV Circuit Monitoring (along feeder) w/ State Estimation	Extensively used at transmission level but for a different purpose - data resolving discrepancies within a data set that has more than sufficient real measurement points. The distribution challenge is to create 'virtual' measurement points.	TRL 4 Technology basic validation in a laboratory environment.	ED1 innovation tray	8
Enhanced system integrity	2021-2023	Smart Metering System (LV)	Monitor critical LV network parameters: 4Q hh flows RMS hh avg. voltage Voltage sag / swell	Connectivity model to enable aggregation of SM data to produce demand/voltage time-series profile Data extraction from DCC to UK	Smart Metering infrastructure - DCC to DNO 1 way	Technically compliant meters available from Q2 2012 – near 100% coverage by 2020	TRL 8 Actual Technology completed and qualified through test and demonstration.	Smart Metering readiness strategic project	11

ED1 deliverable	Timing	Capability requirements	Network Application	Methodology	Known as in WS3 model	Business / Technology Readiness Level	Formal TRL level	Innovation tray	Resilience to different economic and low carbon scenarios (15 = highly resilient; 0 = highly sensitive)
				Power Networks ODS					
Enhanced system integrity	2021-2023	Dist. S/S Monitoring (MV/HV)	Monitor critical LV network parameters: Import / export hh flows PF RMS hh avg. busbar voltage THD Phase imbalance Ambient Temp	Data extraction from S/S RTU to UK Power Networks ODS	HV Circuit Monitoring (along feeder)	Technologies currently available – UK Power Networks and WPD evaluating retrofit options (CT's / Rogowski coils / etc.)	TRL 7 Technology prototype demonstration in an operational environment.	Smart Network Plan (SNP)	11
Improved load and loss load factor	2021-2023	Inverter PF management (MV / LV)	MV / LV networks with inverter connected DER – e.g. PV arrays	Control phase angle of inverter export to limit voltage rise	Generator network support - HV connected	Embryonic – limited control capability of existing inverters in use	TRL 5 Technology basic validation in a relevant environment.	ED1 innovation tray	6
Improved load and loss load factor	2021-2023	Active generation constraint	Managing DG to optimise network capacity	Regulating DG real and reactive power flows according to real-time network capacity	Generation constraint management - EHV connected	Proven prototypes – including Scroby Sands, Orkney / Shetland Isles	TRL 7 Technology prototype demonstration in an operational	Smart Network Plan (SNP)	10

ED1 deliverable	Timing	Capability requirements	Network Application	Methodology	Known as in WS3 model	Business / Technology Readiness Level	Formal TRL level	Innovation tray	Resilience to different economic and low carbon scenarios (15 = highly resilient; 0 = highly sensitive)
							environment.		
Improved load and loss load factor	2021-2023	TOU - Variable rate / fixed time-banded tariff	Domestic and commercial customers Applicable to both energy and DUoS tariffs	Individually time-banded rates to encourage / reward usage low energy price or off peak periods	DNO to residential	Dependent for application on smart metering and compatible billing / settlement systems	TRL 5 Technology basic validation in a relevant environment.	Smart Network Plan (SNP)	5
Improved load and loss load factor	2021-2023	Li-ion battery	Large Scale electrical storage	Connected to network via VSC to improve network load and power factor, and power quality	HV connected EES - large	Being trialled by UK Power Networks Unclear at this stage which if any technology (e.g. NAS or LI-ion – or even Nickel based) will prove more viable. [Note that TRL level refers to the readiness of commercial models more than technology readiness.]	TRL 5 Technology basic validation in a relevant environment.	ED1 innovation tray	3
Losses optimisation	2021-2023	MD Tariff	Industrial & Commercial customers	Composite tariffs charging for both consumption (kW / kVAr) and demand (kVA) – may also include poor PF penalty rate	DNO to HV commercial DSR	Established	TRL 9 Actual Technology qualified through successful mission operations.	Business as Usual (BAU)	7

ED1 deliverable	Timing	Capability requirements	Network Application	Methodology	Known as in WS3 model	Business / Technology Readiness Level	Formal TRL level	Innovation tray	Resilience to different economic and low carbon scenarios (15 = highly resilient; 0 = highly sensitive)
Losses optimisation	2021-2023	TOU - Variable rate / fixed time-banded tariff	Domestic and commercial customers Applicable to both energy and DUoS tariffs	Individually time-banded rates to encourage / reward usage low energy price or off peak periods	DNO to residential	Dependent for application on smart metering and compatible billing / settlement systems	TRL 5 Technology basic validation in a relevant environment.	Smart Network Plan (SNP)	5
Losses optimisation	2021-2023	Local LV network automation	LV networks with series L/Bs	Sectionalisation of LV faults through switchable L/Bs	Dynamic Network Reconfiguration - LV	Trials under development	TRL 6 Technology model or prototype demonstration in a relevant environment.	ED1 innovation tray	8
Provision of upstream system balancing services	2021-2023	Customer Relationship Management database	Demand Side Response and energy efficiency opportunities	0	DATA SYSTEMS	0	TRL 7 Technology prototype demonstration in an operational environment.	Smart Network Plan (SNP)	8
Provision of upstream system balancing services	2021-2023	Responsive demand security support	Contracted responsive demand for network security support	Striking contracts with I&C customers to provide short term net demand curtailment (pre	DNO to aggregator led HV commercial DSR	Proof of concept trials (LCL) Methodology and feasibility will be evaluated through LCL programme	TRL 7 Technology prototype demonstration in an operational environment.	Smart Network Plan (SNP)	10

ED1 deliverable	Timing	Capability requirements	Network Application	Methodology	Known as in WS3 model	Business / Technology Readiness Level	Formal TRL level	Innovation tray	Resilience to different economic and low carbon scenarios (15 = highly resilient; 0 = highly sensitive)
				or post fault as required)					
Provision of upstream system balancing services	2021-2023	Embedded generation security support	Constraining-on contracts with DG operators for network security support	Contracts with DG operators to provide generation export support (pre or post fault as required)	Generation constraint management - HV connected	Extension of proven generation active management technology	TRL 7 Technology prototype demonstration in an operational environment.	Smart Network Plan (SNP)	10
Provision of upstream system balancing services	2021-2023	Li-ion battery	Large Scale electrical storage	Connected to network via VSC to improve network load and power factor, and power quality	HV connected EES - large	Being trialled by UK Power Networks Unclear at this stage which if any technology (e.g. NAS or LI-ion – or even Nickel based) will prove more viable. [Note that TRL level refers to the readiness of commercial models more than technology readiness.]	TRL 5 Technology basic validation in a relevant environment.	ED1 innovation tray	3
Smart management of Distributed Energy Resources	2021-2023	In-line voltage regulator (LV)	LV OHL networks with high levels of voltage regulation and/or phase imbalance	Applied to LV OHL networks where MV/LV Tfr OLTC not available (Moving coil type historically used in conjunction	Enhanced AVC - LV circuit voltage regulators	Available	TRL 9 Actual Technology qualified through successful mission operations.	Business as Usual (BAU)	3

ED1 deliverable	Timing	Capability requirements	Network Application	Methodology	Known as in WS3 model	Business / Technology Readiness Level	Formal TRL level	Innovation tray	Resilience to different economic and low carbon scenarios (15 = highly resilient; 0 = highly sensitive)
				with phase balancer)					
Smart management of Distributed Energy Resources	2021-2023	Dist Tfr with on-load position switching (LV)	LV networks with high levels of voltage regulation	On-load tap position switching to regulate LV voltage profile	Enhanced AVC - HV/LV Transformer Voltage Control	Products under trial and available	TRL 7 Technology prototype demonstration in an operational environment.	ED1 innovation tray	6
Smart management of Distributed Energy Resources	2021-2023	Smart Metering System (LV)	Monitor critical LV network parameters: 4Q hh flows RMS hh avg. voltage Voltage sag / swell	Connectivity model to enable aggregation of SM data to produce demand/voltage time-series profile Data extraction from DCC to UK Power Networks ODS	Smart Metering infrastructure - DCC to DNO 1 way	Technically compliant meters available from Q2 2012 – near 100% coverage by 2020	TRL 8 Actual Technology completed and qualified through test and demonstration.	Smart Metering readiness strategic project	11

ED1 deliverable	Timing	Capability requirements	Network Application	Methodology	Known as in WS3 model	Business / Technology Readiness Level	Formal TRL level	Innovation tray	Resilience to different economic and low carbon scenarios (15 = highly resilient; 0 = highly sensitive)
Smart management of Distributed Energy Resources	2021-2023	Dist. S/S Monitoring (MV/HV)	Monitor critical LV network parameters: Import / export hh flows PF RMS hh avg. busbar voltage THD Phase imbalance Ambient Temp	Data extraction from S/S RTU to UK Power Networks ODS	HV Circuit Monitoring (along feeder)	Technologies currently available – UK Power Networks and WPD evaluating retrofit options (CT's / Rogowski coils / etc.)	TRL 7 Technology prototype demonstration in an operational environment.	Smart Network Plan (SNP)	11
Smart management of Electric Vehicles (EVs) and heat pumps	2021-2023	All-Electric Vehicles / PHEVs	Personal and commercial electric vehicle transportation	Either ICE / battery hybrid or all electric vehicle	(not allocated)	Rapidly evolving Products available Economically viable with current subsidies / exemptions	TRL 7 Technology prototype demonstration in an operational environment.	ED1 innovation tray	8
Smart management of Electric Vehicles (EVs) and heat pumps	2021-2023	Electric space / water heating (inc. heat pumps) with heat storage	Domestic and SME electric heating	Primarily heat pumps possibly accompanied by some supplementary direct heating	DSR - Products to remotely control loads at consumer premises	Established ground and air source technologies	TRL 8 Actual Technology completed and qualified through test and demonstration.	ED2 innovation tray	6

ED1 deliverable	Timing	Capability requirements	Network Application	Methodology	Known as in WS3 model	Business / Technology Readiness Level	Formal TRL level	Innovation tray	Resilience to different economic and low carbon scenarios (15 = highly resilient; 0 = highly sensitive)
Smart management of Electric Vehicles (EVs) and heat pumps	2021-2023	TOU - Variable rate / fixed time-banded tariff	Domestic and commercial customers Applicable to both energy and DUoS tariffs	Individually time-banded rates to encourage / reward usage low energy price or off peak periods	DNO to residential	Dependent for application on smart metering and compatible billing / settlement systems	TRL 5 Technology basic validation in a relevant environment.	Smart Network Plan (SNP)	5
Smart management of Electric Vehicles (EVs) and heat pumps	2021-2023	Local intelligent EV charging control	Peak avoidance	An EV charging solution applied by the DNO to apportion capacity to several EVs on a feeder across a charging cycle.	DNO-controlled EV charging - LV domestic connected	Technology proposals only at this stage.	TRL 5 Technology basic validation in a relevant environment.	Other DNOs' and National Grid innovation tray	#N/A
System voltage optimisation	2021-2023	Synchro-phasers (PMUs) and IEDs (MV / HV / EHV)	System model validation Determining stability margins Maximising stable system loading Islanding detection System-wide disturbance recording Visualisation of dynamic system response Control of DG	Real-time measurement of electrical quantities across the system using high frequency (typically 30 per sec.) GPS time-stamped measurement	(not allocated)	Mature and increasingly applied to inter-connected transmission systems Few if any distribution system applications to date	TRL 6 Technology model or prototype demonstration in a relevant environment.	ED1 innovation tray	3

ED1 deliverable	Timing	Capability requirements	Network Application	Methodology	Known as in WS3 model	Business / Technology Readiness Level	Formal TRL level	Innovation tray	Resilience to different economic and low carbon scenarios (15 = highly resilient; 0 = highly sensitive)
			Advanced automation						
System voltage optimisation	2021-2023	Statcom (EHV / HV / MV)	Reducing reactive flows in distribution lines and improving voltage stability	Shunt connected voltage source converter using IGBT PWM	STATCOM - EHV	D-Stacoms available – suitable for distribution systems	TRL 6 Technology model or prototype demonstration in a relevant environment.	ED2 innovation tray	6
Facilitating higher levels of DG penetration	2018-2020	Active network management (general)	Where real time or real time network configuration / voltage control / demand control is required	Includes active control of power flows, demand, voltage, DG export, network open points etc.	Dynamic Network Reconfiguration - EHV	Distributed energy management systems commercially available	TRL 6 Technology model or prototype demonstration in a relevant environment.	Smart Network Plan (SNP)	10
Facilitating higher levels of DG penetration	2018-2020	Active generation constraint	Managing DG to optimise network capacity	Regulating DG real and reactive power flows according to real-time network capacity	Generation constraint management - EHV connected	Proven prototypes – including Scroby Sands, Orkney / Shetland Isles	TRL 7 Technology prototype demonstration in an operational environment.	Smart Network Plan (SNP)	10

ED1 deliverable	Timing	Capability requirements	Network Application	Methodology	Known as in WS3 model	Business / Technology Readiness Level	Formal TRL level	Innovation tray	Resilience to different economic and low carbon scenarios (15 = highly resilient; 0 = highly sensitive)
Facilitating higher levels of DG penetration	2018-2020	Fault Current Limiter (MV)	MV primary substations – ideally in series with bus / sections couplers – or controlling circuits with high fault infeed (transformer feeders or significant DG connections)	Acts as non-linear / saturation reactor – maintains low source impedance under normal loading but increasing impedance under fault conditions Several technologies under development	HV Non-superconducting fault current limiters	Systems under development SC and non-SC technologies available	TRL 6 Technology model or prototype demonstration in a relevant environment.	Smart Network Plan (SNP)	11
Improved network visualisation	2018-2020	Digsilent Power Factory	Power network modelling	Enable the response of the power network to be modelled to ensure correct / safe operation	Design tools	Available now	TRL 9 Actual Technology qualified through successful mission operations.	Business as Usual (BAU)	10

ED1 deliverable	Timing	Capability requirements	Network Application	Methodology	Known as in WS3 model	Business / Technology Readiness Level	Formal TRL level	Innovation tray	Resilience to different economic and low carbon scenarios (15 = highly resilient; 0 = highly sensitive)
Improved network visualisation	2018-2020	Dist. S/S Monitoring (MV/HV)	Monitor critical LV network parameters: Import / export hh flows PF RMS hh avg. busbar voltage THD Phase imbalance Ambient Temp	Data extraction from S/S RTU to UK Power Networks ODS	HV Circuit Monitoring (along feeder)	Technologies currently available – UK Power Networks and WPD evaluating retrofit options (CT's / Rogowski coils / etc.)	TRL 7 Technology prototype demonstration in an operational environment.	Smart Network Plan (SNP)	11
Improved network visualisation	2018-2020	Operational data store (ODS)	Storage, linking and analysis of network / smart grid / meter data	System to store and link relevant data to allow analysis Also contains some data analysis tools (PI ACE)	(not allocated)	Existing PI system is established for primary system data Development of ODS for secondary system and smart metering data via LCL project	TRL 7 Technology prototype demonstration in an operational environment.	Smart Metering readiness strategic project	15
Improved network visualisation	2018-2020	Control room / asset management visualisation tools	Condition / Duty monitoring and management	Monitor in real time the condition / duty of major assets such as transformers, switchgear etc.	Advanced control systems	Under development	TRL 7 Technology prototype demonstration in an operational environment.	Smart Network Plan (SNP)	10

ED1 deliverable	Timing	Capability requirements	Network Application	Methodology	Known as in WS3 model	Business / Technology Readiness Level	Formal TRL level	Innovation tray	Resilience to different economic and low carbon scenarios (15 = highly resilient; 0 = highly sensitive)
Increased supply resilience	2018-2020	Distributed / autonomous automation systems for post-fault and real-time network configuration optimisation at MV	Post-fault sectionalisation Pre-fault optimisation	Local / regional autonomous control system with more flexible restoration / optimisation sequencing	Dynamic Network Reconfiguration - HV	Simple versions were developed by Central Networks. Potentially to be incorporated into PowerOn release ca. 2015	TRL 6 Technology model or prototype demonstration in a relevant environment.	ED1 innovation tray	10
Increased supply resilience	2018-2020	Active network management (general)	Where real time or real time network configuration / voltage control / demand control is required	Includes active control of power flows, demand, voltage, DG export, network open points etc.	Dynamic Network Reconfiguration - EHV	Distributed energy management systems commercially available	TRL 6 Technology model or prototype demonstration in a relevant environment.	Smart Network Plan (SNP)	10
Power outage management	2018-2020	Smart Metering System (LV/MV)	Power outage / event management Energisation status polling Loss of supply alarm Hi-Lo voltage alarm / disconnect	Connectivity model to map meter points to LV network Data extraction from DCC to UK Power Networks ODS	Smart Metering infrastructure - DNO to DCC 2 way A+D	Technically compliant meters available from Q2 2012 – near 100% coverage by 2020	TRL 8 Actual Technology completed and qualified through test and demonstration.	Smart Metering readiness strategic project	15

ED1 deliverable	Timing	Capability requirements	Network Application	Methodology	Known as in WS3 model	Business / Technology Readiness Level	Formal TRL level	Innovation tray	Resilience to different economic and low carbon scenarios (15 = highly resilient; 0 = highly sensitive)
Power outage management	2018-2020	Operational data store (ODS)	Storage, linking and analysis of network / smart grid / meter data	System to store and link relevant data to allow analysis Also contains some data analysis tools (PI ACE)	(not allocated)	Existing PI system is established for primary system data Development of ODS for secondary system and smart metering data via LCL project	TRL 7 Technology prototype demonstration in an operational environment.	Smart Metering readiness strategic project	15
Voltage quality management	2018-2020	Dist. S/S Monitoring (MV/HV)	Monitor critical LV network parameters: Import / export hh flows PF RMS hh avg. busbar voltage THD Phase imbalance Ambient Temp	Data extraction from S/S RTU to UK Power Networks ODS	HV Circuit Monitoring (along feeder)	Technologies currently available – UK Power Networks and WPD evaluating retrofit options (CT's / Rogowski coils / etc.)	TRL 7 Technology prototype demonstration in an operational environment.	Smart Network Plan (SNP)	11
Voltage quality management	2018-2020	Harmonic filters (EHV / HV / MV ?)	Reducing harmonics generated from power-electronic loads (e.g. rail / industrial) and generators (e.g. large-scale PV)	Applied at point of connection or primary or grid substation.	(not allocated)	Available	TRL 9 Actual Technology qualified through successful mission operations.	Business as Usual (BAU)	#N/A

ED1 deliverable	Timing	Capability requirements	Network Application	Methodology	Known as in WS3 model	Business / Technology Readiness Level	Formal TRL level	Innovation tray	Resilience to different economic and low carbon scenarios (15 = highly resilient; 0 = highly sensitive)
Enhanced control systems resilience	2015-2017	Cyber security systems	Security of critical systems – including NMS	Monitor and apply relevant industry standards Ensure updated in light of any new potential risk / threat	DATA SYSTEMS	Available now and regularly updated Will require systematic regular review to ensure provisions adequate for smart grid related threats	TRL 7 Technology prototype demonstration in an operational environment.	ED1 innovation tray	15
Enhanced control systems resilience	2015-2017	Data protection systems	Protection of customer data	Monitor and apply relevant industry standards Ensure updated in light of any new potential risk / threat	DATA SYSTEMS	Standards will emerge over 2013-15 as the DCC is chosen and the interface between DNO and DCC becomes clearer.	TRL 5 Technology basic validation in a relevant environment.	Smart Metering readiness strategic project	11
Enhanced system security through procured ancillary services	2015-2017	Responsive demand security support	Contracted responsive demand for network security support	Striking contracts with I&C customers to provide short term net demand curtailment (pre or post fault as required)	DNO to aggregator led HV commercial DSR	Proof of concept trials (LCL) Methodology and feasibility will be evaluated through LCL programme	TRL 7 Technology prototype demonstration in an operational environment.	Smart Network Plan (SNP)	10
Enhanced system security through	2015-2017	Embedded generation security support	Constraining-on contracts with DG operators for	Contracts with DG operators to provide	Generation constraint management -	Extension of proven generation active management technology	TRL 7 Technology prototype	Smart Network Plan (SNP)	10

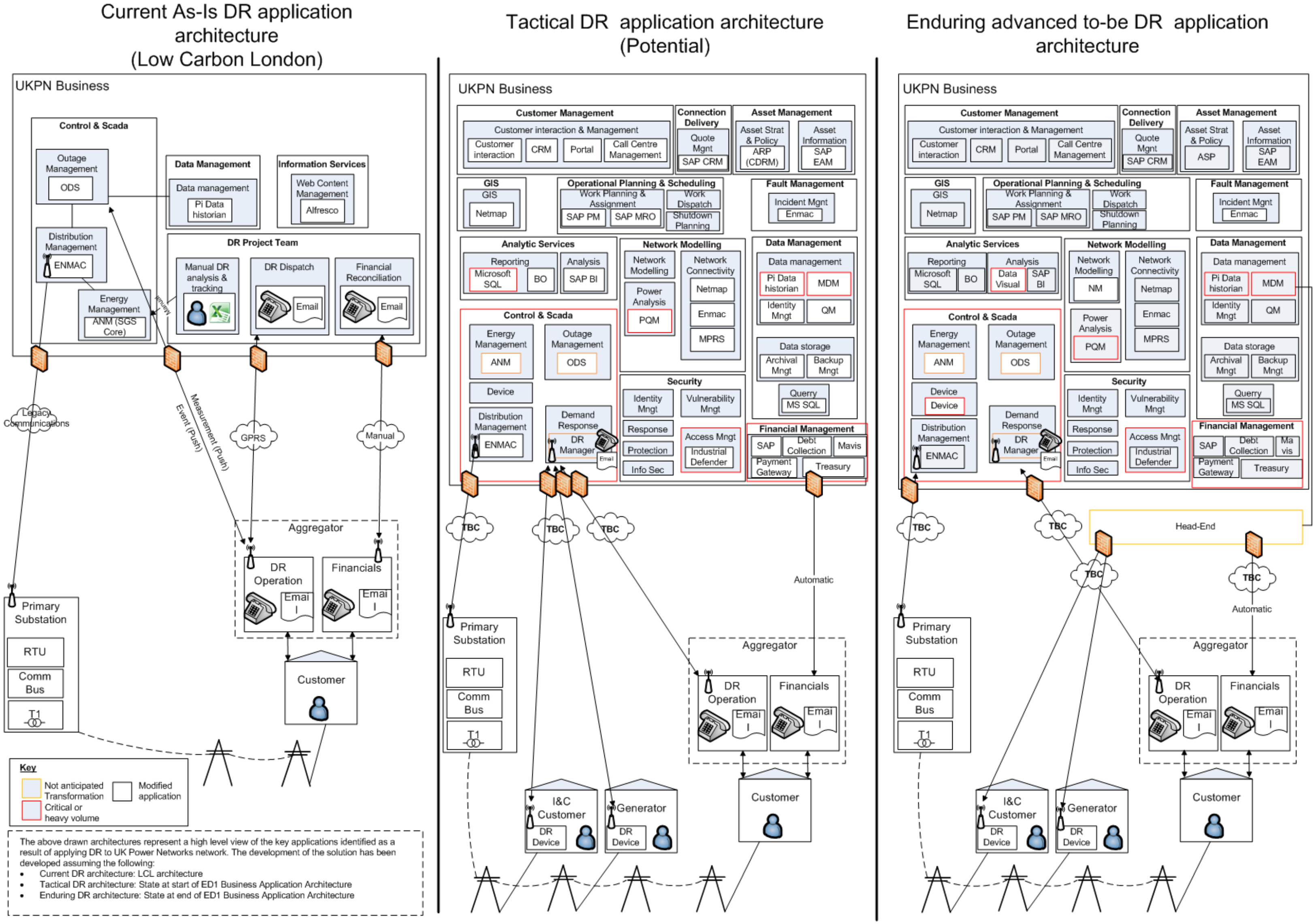
ED1 deliverable	Timing	Capability requirements	Network Application	Methodology	Known as in WS3 model	Business / Technology Readiness Level	Formal TRL level	Innovation tray	Resilience to different economic and low carbon scenarios (15 = highly resilient; 0 = highly sensitive)
procured ancillary services			network security support	generation export support (pre or post fault as required)	HV connected		demonstration in an operational environment.		
Enhanced system security through procured ancillary services	2015-2017	Li-ion battery	Large Scale electrical storage	Connected to network via VSC to improve network load and power factor, and power quality	HV connected EES - large	Being trialled by UK Power Networks Unclear at this stage which if any technology (e.g. NAS or LI-ion – or even Nickel based) will prove more viable. [Note that TRL level refers to the readiness of commercial models more than technology readiness.]	TRL 5 Technology basic validation in a relevant environment.	ED1 innovation tray	3
Increased plant and line utilisation	2015-2017	Active Dynamic Rating Cables	Real-time rating of plant and equipment to maximise capacity	Continuous measurement of rating criteria to determine safe maximum loading	RTTR for EHV Underground Cables	Less developed than overhead lines and transformers, and relies on data (direct lay or ducted, trench depth, soil type, neighbouring cables, etc.)	TRL 6 Technology model or prototype demonstration in a relevant environment.	ED1 innovation tray	10
Increased plant and line utilisation	2015-2017	Active network management (general)	Where real time or real time network configuration / voltage control / demand control is required	Includes active control of power flows, demand, voltage, DG export, network open points etc.	Dynamic Network Reconfiguration - EHV	Distributed energy management systems commercially available	TRL 6 Technology model or prototype demonstration in a relevant	Smart Network Plan (SNP)	10

ED1 deliverable	Timing	Capability requirements	Network Application	Methodology	Known as in WS3 model	Business / Technology Readiness Level	Formal TRL level	Innovation tray	Resilience to different economic and low carbon scenarios (15 = highly resilient; 0 = highly sensitive)
							environment.		
Increased plant and line utilisation	2015-2017	Active Dynamic Rating Overhead lines	Real-time rating of plant and equipment to maximise capacity	Continuous measurement of rating criteria to determine safe maximum loading	RTTR for EHV Overhead Lines	Existing applications for overhead lines and cables	TRL 7 Technology prototype demonstration in an operational environment.	Smart Network Plan (SNP)	10
Increased plant and line utilisation	2015-2017	Active Dynamic Rating Transformers	Real-time rating of plant and equipment to maximise capacity	Continuous measurement of rating criteria to determine safe maximum loading	RTTR for EHV/HV transformers	Transformer thermal modelling techniques established	TRL 7 Technology prototype demonstration in an operational environment.	Smart Network Plan (SNP)	10
Increased plant and line utilisation	2015-2017	Control room / asset management visualisation tools	Condition / Duty monitoring and management	Monitor in real time the condition / duty of major assets such as transformers, switchgear etc.	Advanced control systems	Under development	TRL 7 Technology prototype demonstration in an operational environment.	Smart Network Plan (SNP)	10

A.2 DSR ICT architectures

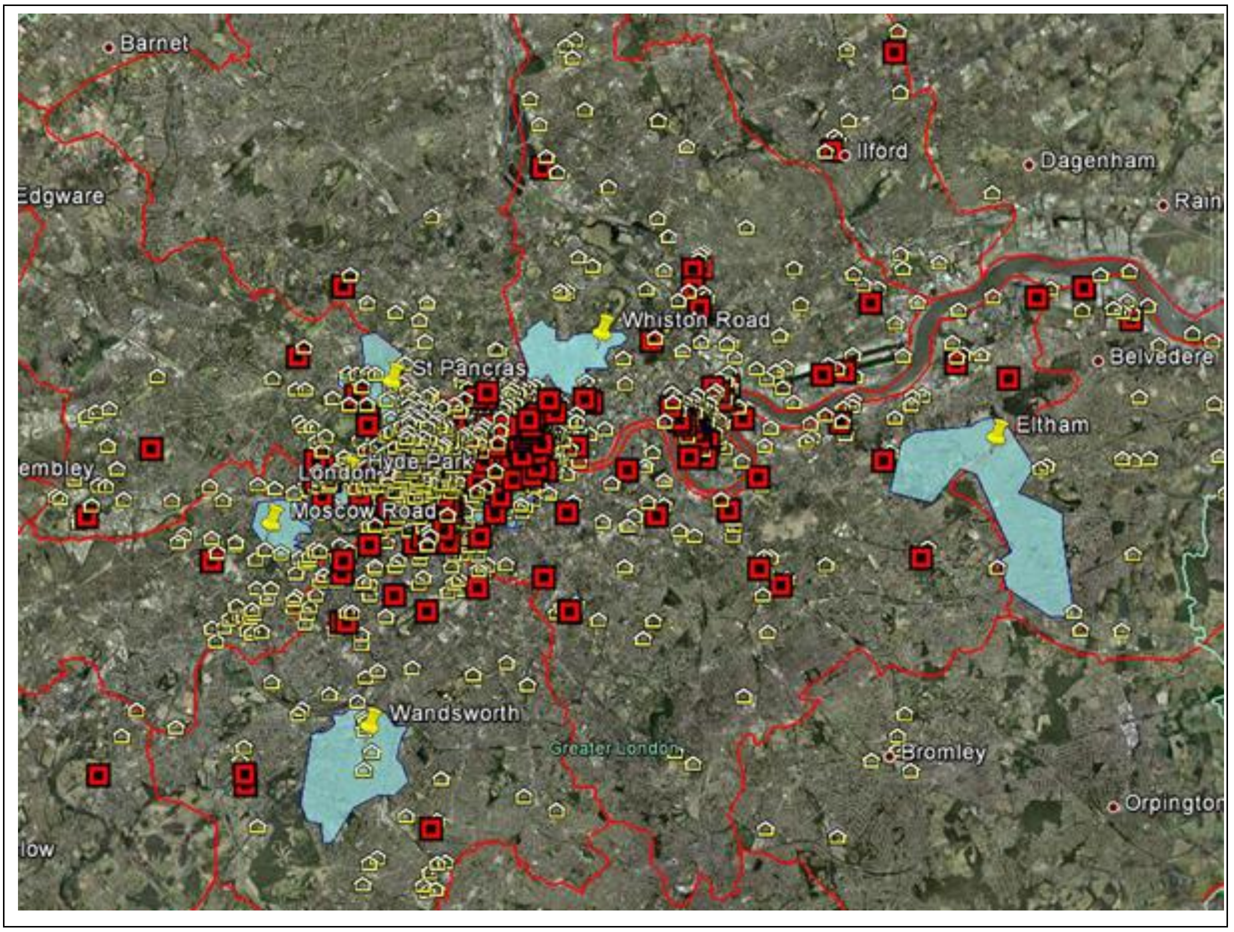
Figure 26 shows an example of how we are planning to evolve IT architectures in order to support (in this case) Demand Side Response.

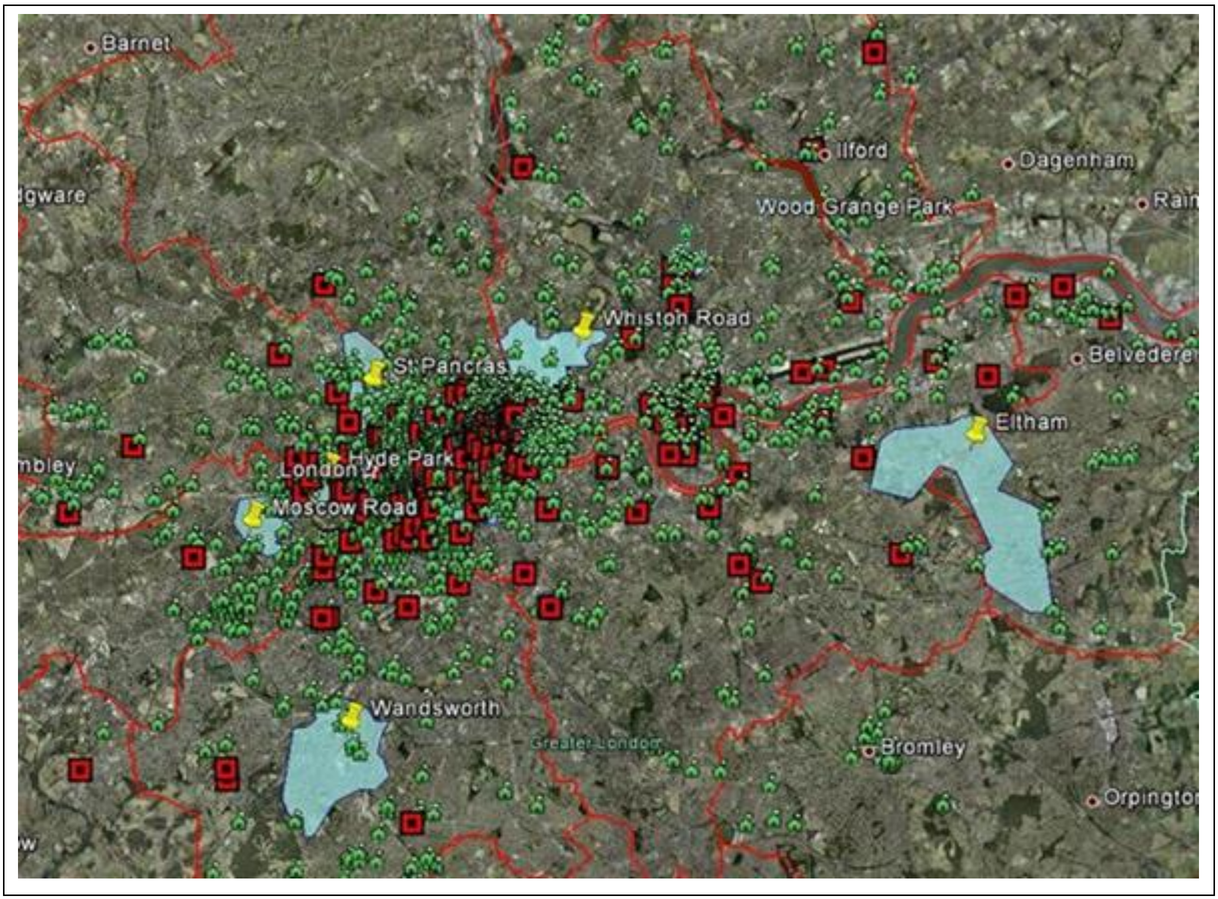
Figure 26 IT architecture to support Demand Side Response



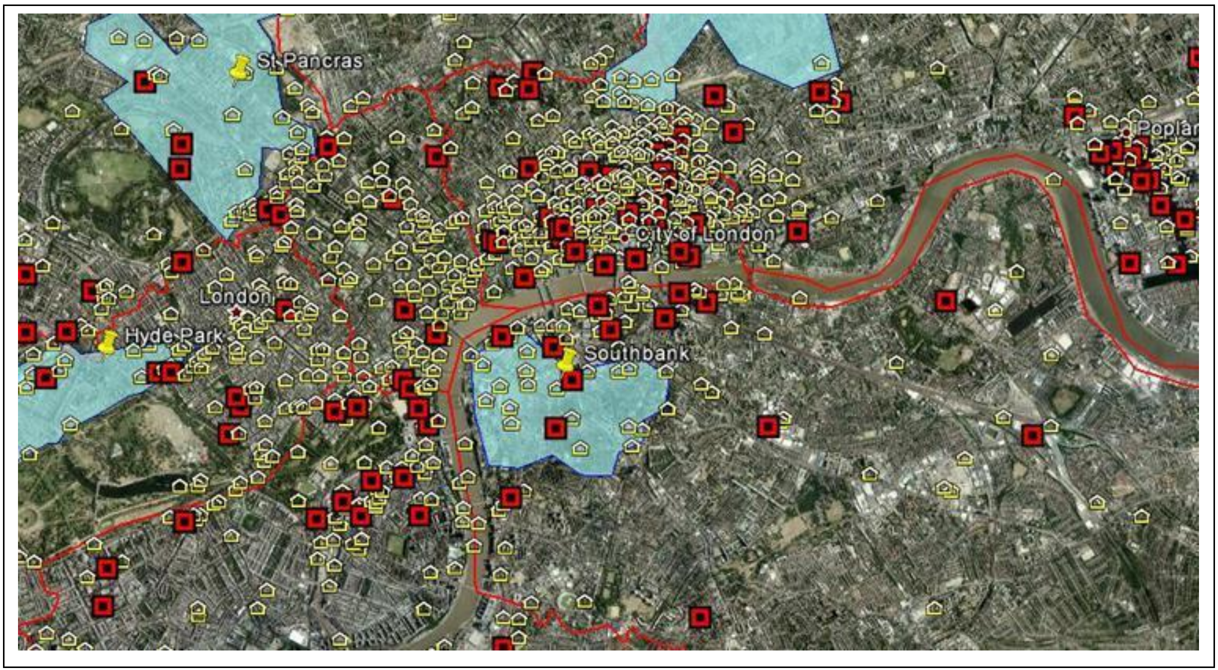
A.3 Demand side response maps

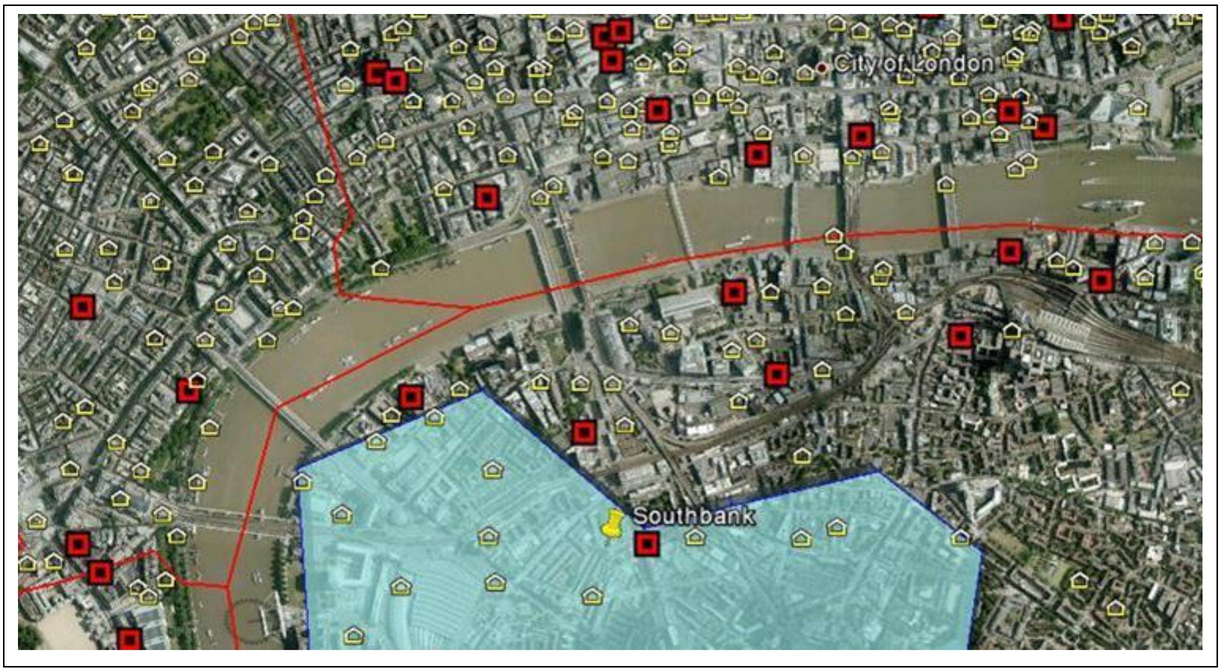
A.3.1 LPN



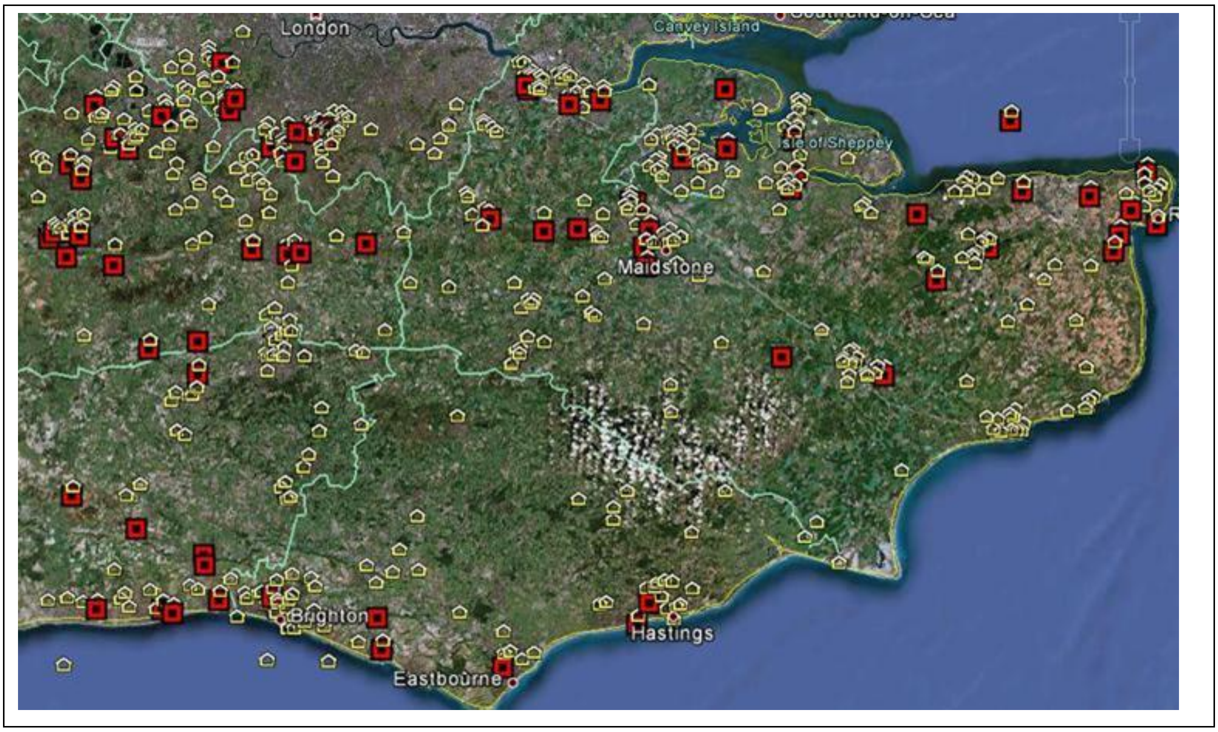


The red squares represent sites with non-intermittent generation capacity of 500 kW and above. The green houses, in the second map, represent industrial and commercial sites that have a declared site capacity above 500 KW. The yellow houses, in the first map, indicate the industrial and commercial sites that have recorded a maximum demand of 500 kW or more. The blue shaded areas represent the catchment area of substations that have been identified for DSR. 500 kW has been chosen as a value as it is believed that these sites would be able to provide DSR services. It is not the case that smaller aggregated sites will not be able to provide a sufficient DSR services but for the purposes of this document the focus will be on the indicated sites

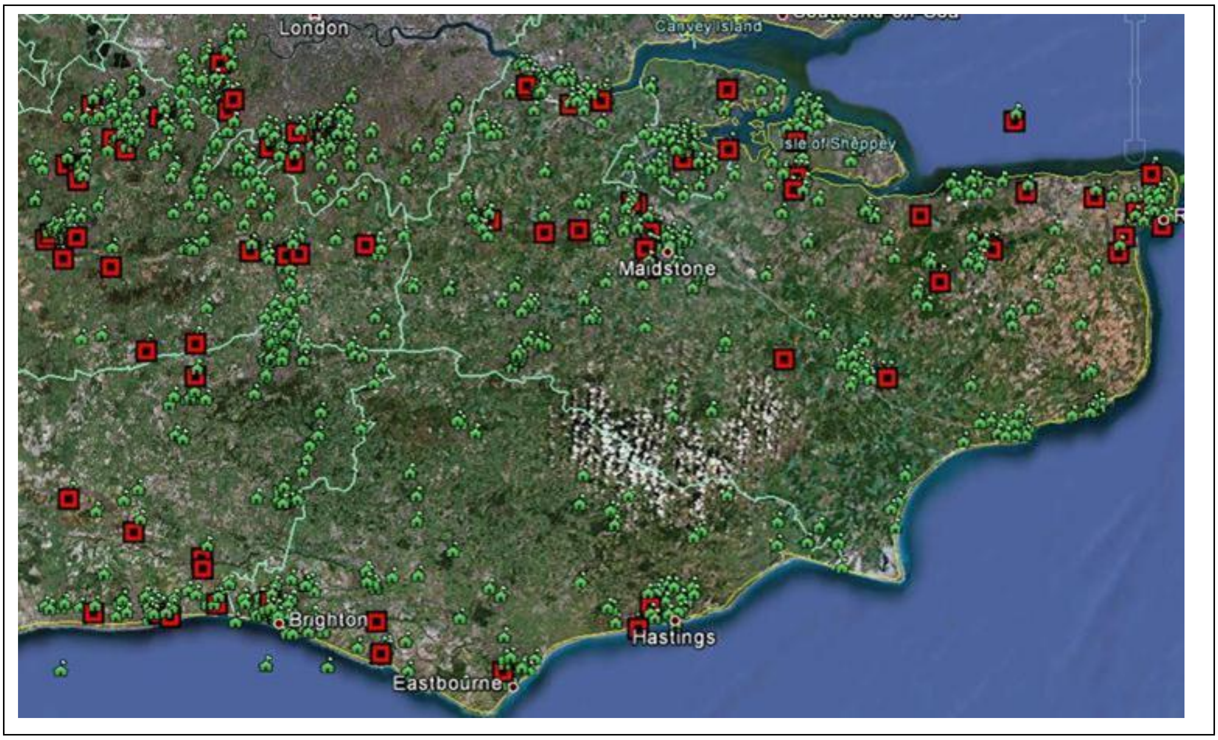




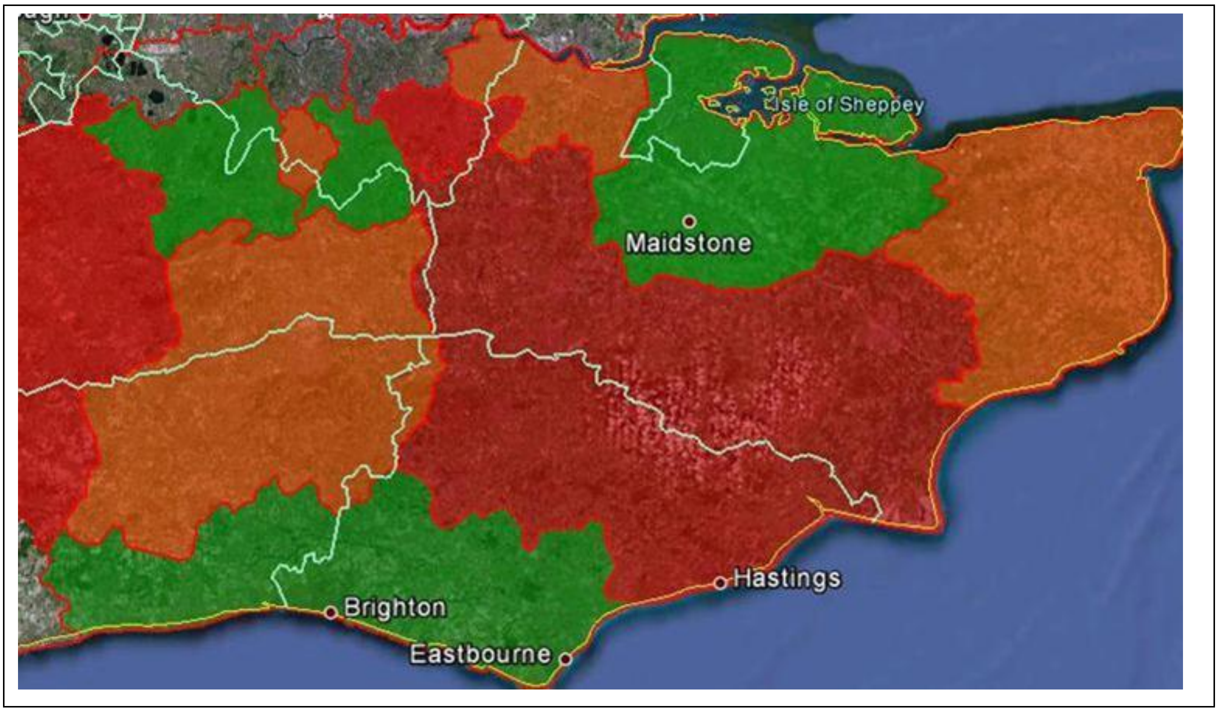
A.3.2 SPN



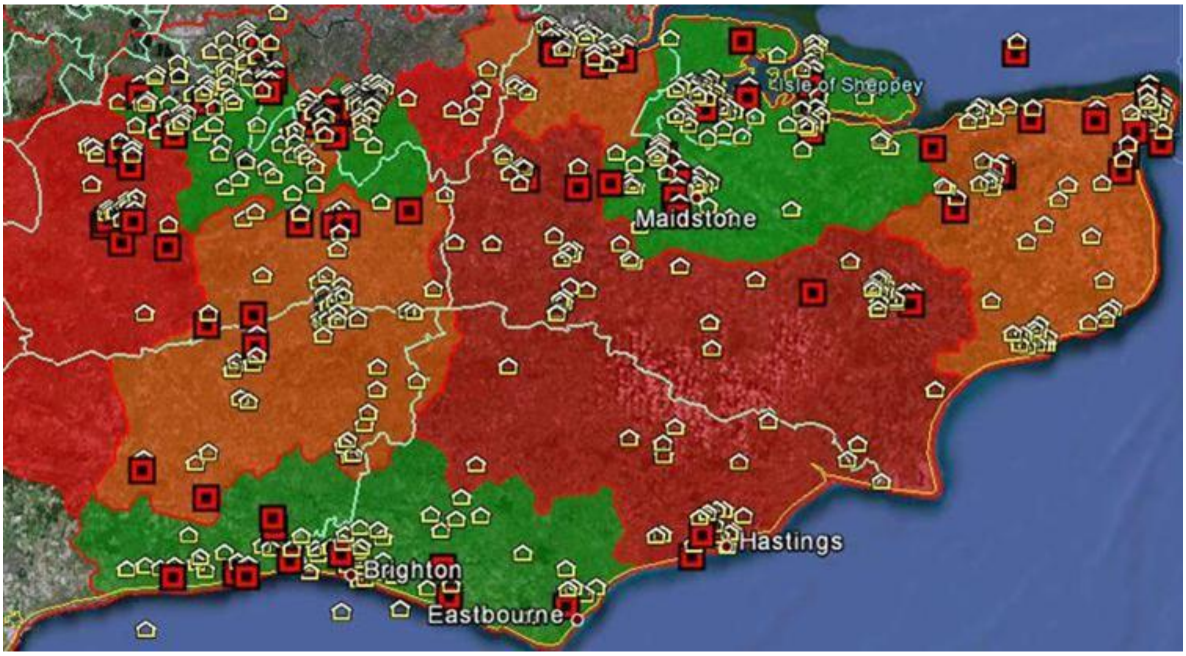
Sites with non-intermittent generation above 500 kW and sites with a declared capacity of 500 kW or more



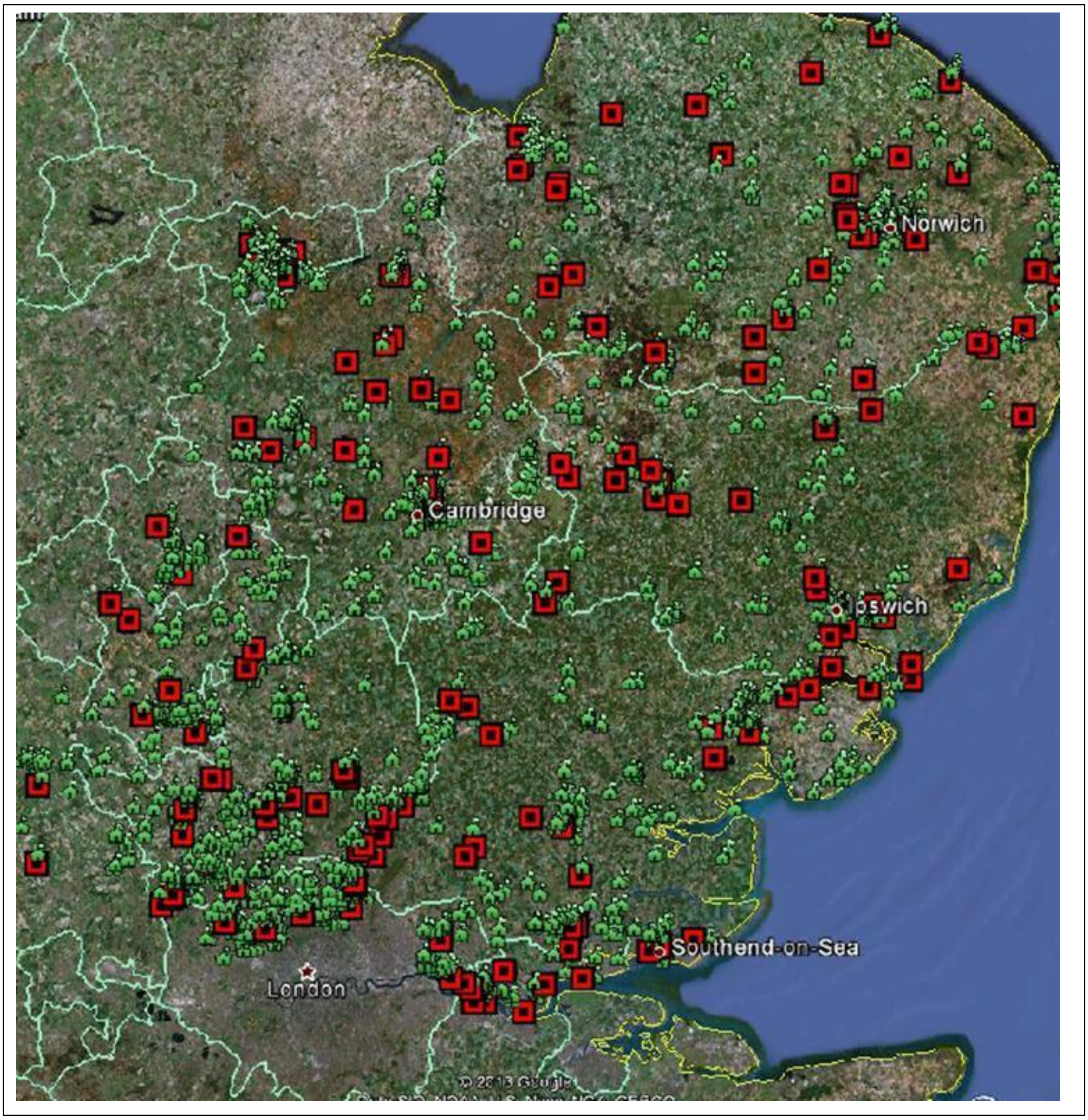
Sites with non-intermittent generation above 500 kW and sites that have recorded a maximum demand of 500 kW of more



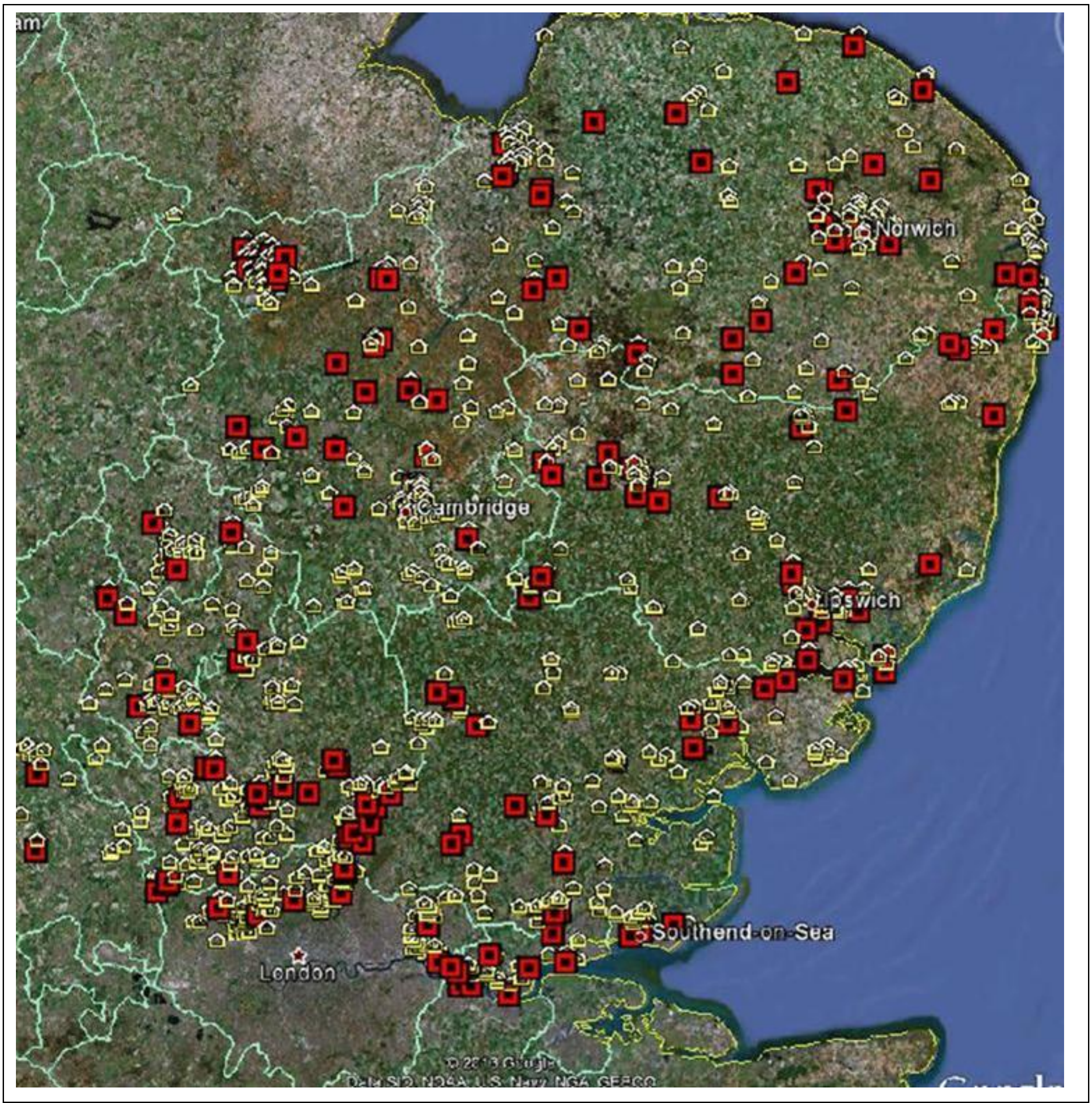
Green indicates a high probability of procuring DSR services. Amber indicates that DSR services can be procured but recruitment may face challenges. Red indicates DSR opportunities are very low

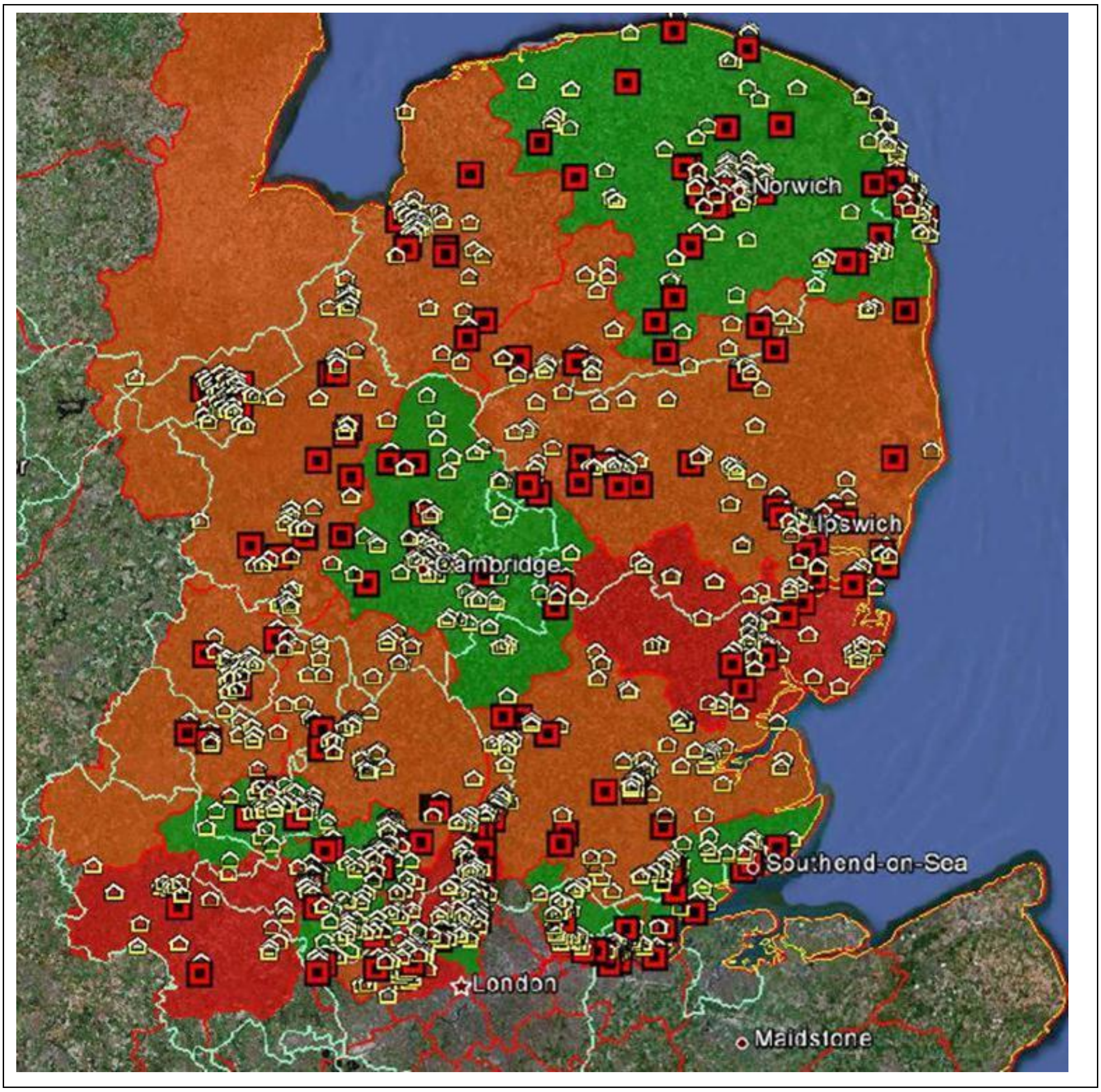

Isle of Sheppey
Maidstone
Hastings
Brighton
Eastbourne

A.3.3 EPN



Norwich
Cambridge
Ipswich
Southend-on-Sea
London
© 2013 Google


Norwich
Cambridge
Ipswich
Southend-on-Sea
London


Norwich
Ipswich
Cambridge
Southend-on-Sea
London
Maidstone

A.4 Transform model parameters

Parameter	Ofgem requirement	Compliance statement
Cost-Benefit Analysis (CBA) period	45 years	We have made no changes to either the solution parameters or the model functionality. As such the CBA method is 'as shipped' with Transform.
Price base	2012/13	Our "DNO Best view" submission is in 2012/13 prices and is based on a combination of the Imperial LRE model, site-by-site analysis and Transform. We have provided a workbook with verbatim outputs from Transform in the four DECC scenarios in 2011/12 prices and which is directly comparable to our previous submissions of Transform model outputs to Ofgem in December 2012 and January 2013.
Base year	2015/16	Early years 2011/12 through to 2014/15 are used to calibrate the model and provide in the Business Plan Data Template sheet for information only. Model outputs are considered stable from 2015/16 onwards.
Depreciation calculation	Use straight line depreciation consistent with ED1 financial models, Assume depreciation starts 1 year after investment, consistent with ED1 financial model.	The Transform model depreciates using straight line depreciation from the moment of installation.
Conversion of capital costs to annual costs recovered through customers' bills / Capitalisation assumptions	Applied to all financial costs (investment costs and benefits); the capitalisation rates assumptions in CBA models should be consistent with those stated in DNOs individual business plan.	We have made no changes to either the solution parameters or the model functionality. As such the CBA method and Weighted Average Cost of Capital (WACC) assumption within the CBA calculation is 'as shipped' with Transform.
RPEs	For clarity costs should be entered consistent with BPDT submissions i.e. assume RPEs = zero, net of ongoing productivity.	Compliant
Financial benefits in year 1	Assume zero benefits are realised in first year of investment, 100% benefits are realised from year 2 of investment and beyond	The Transform model replaces conventional solutions with Smart Grid solutions 'in-year' and as such benefits commence in-year.
Discount rate	Assume STPR of 3.5% for all (except safety) costs and benefits, 3% beyond year 30. For safety costs and benefits assume 1.5% PTPR.	Discount rate of 3.5% has been used in the model. The Smart Grid solutions included in our business plan have not needed to rely on safety costs and benefits.
Carbon abatement values	– DECC traded carbon values14 for electricity distribution.	– This has not been built into the Transform model functionality.
Reduction of electricity lost	– Use the wholesale price of electricity less the EU Emissions Trading Scheme (ETS) cost of carbon (which is factored into the wholesale price) plus the carbon abatement value described below. To account for price fluctuations, we suggested we would set a standard £/MWh value and base this	– This has not been built into the Transform model functionality.

Parameter	Ofgem requirement	Compliance statement
	on average wholesale and carbon prices over 2011-12.	