# NIA ENWL001
# Demand Scenarios with Electric Heat and Commercial Capacity Options

## Closedown Report

**7 March 2017**

# CONTENTS

## GLOSSARY

| Term | Description |
|---|---|
| ACS | Average Cold Spell – winter peak in a median year for weather |
| ATLAS | Architecture of Tools for Load Scenarios (www.enwl.co.uk/atlas)<br>A NIA project |
| BSP | Bulk Supply Point – mainly 33kV/132kV for the ENWL network |
| Capacity to Customers ($C_2C$) | Electricity North West's Second Tier LCNF project (2012-2014) which proved post-fault demand response with network automation was technically feasible and deliverable to customers.(www.enwl.co.uk/c2c) |
| CBA | Cost Benefit Analysis – see RO-CBA |
| CDD | Cooling Degree Day – indicative of a future temperature scenario and cooling requirement, which might be met by air conditioning |
| DECC | Department of Energy and Climate Change (source of electric vehicle and heat pump uptake scenarios, used in load modelling) |
| Demand and Generation Dashboard | System to combine half-hourly substation metering data and half-hourly generation export metering data, in order to present the monitored component of true demand |
| DG | Distributed Generation i.e. generation connected to a distribution network |
| DNO | Distribution network operator |
| DSR / DSM | Demand side response / demand side management |
| ENWL | Electricity North West Limited – the DNO for the North West of England |
| EV | Electric vehicle |
| FCH | Future Capacity Headroom model, for the secondary networks |
| FY | Financial year e.g. 2014/15 is FY15 |
| IFI | Innovation Funding Incentive |
| GMT | Ground mounted transformer |
| Grid and primary | G&P network or substations including GSP, BSP and primaries |
| GSP | Grid Supply Point – connection from DNO network to National Grid's transmission network |
| (Hybrid) HP | Heat pump – a hybrid combines an electric heat pump with gas boiler |
| HV | High Voltage eg 6.6kV and 11kV |
| LCNF | Low Carbon Networks Fund |
| LV | Low Voltage eg 230V and 400V |
| MW, MVA | Mega watt, Mega volt amperes – in this project, averaged over half hour |
| NIA | Network Innovation Allowance |
| NPV | Net Present Value |
| PMT | Pole mounted transformer |
| Primary | Primary substation - 6.6kV/33kV or 11kV/33kV for the ENWL network |
| RIIO-ED1 | Revenue = Innovation Incentives Outputs – Electricity Distribution 1<br>The current regulatory period for DNOs – 1 April 2015 -31 March 2023. |

| Term | Description |
|---|---|
| RO-CBA | Real Options approach to Cost Benefit Analysis |
| Transform Model® | Generic model of the electricity networks, developed by EA Technology for Work Stream 3 of the Smart Grid Forum |
| Tyndall | The Tyndall Centre for Climate Change Research |

## VERSION HISTORY

| Version | Date | Author | Status | Comments |
|---|---|---|---|---|
| Work in progress | 14/12/2016 | R Shaw | Work in progress | |
| V1 | 16/12/2016 | R Shaw | Initial draft for internal review | |
| V2 | 19/12/2016 | R Shaw | Second draft for internal review | |
| V3 | 06/01/2017 | R Shaw | Final draft for internal review | Requires updating with Steve Cox comments, awaiting final financial breakdown |
| V4 | 07/03/2017 | R Shaw | Final | Updated following comments from Steve Cox & final financial review |

## REVIEW

| Name | Role | Date |
|---|---|---|
| C Kaloudas | ATLAS Project Contractor | Work in progress version - 14/12/16 |
| G Bryson | Innovation Engineer | V2 – 19/12/16 |
| A Howard | Programme Manager | V2 – 19/12/16 |
| F Mutonono | Reinforcement Planning Engineer | V2 – 19/12/16 |
| J Fallows | Capacity Strategy Manager | V3 – 06/01/117 |
| P Turner | Innovation Delivery Manager | 16/07/17 |

## APPROVAL

| Name | Role | Date |
|---|---|---|
| Steve Cox | Engineering and Technical Director | 20/07/17 |

# 1 EXECUTIVE SUMMARY

*This section does not appear on the Smarter Networks portal.*

## 1.1 Aims

This project aimed to deliver significant incremental improvements in load forecasting per substation by generating peak loading scenarios to inform strategic planning of the distribution network. These scenarios were intended to reflect the major long-term sources of uncertainty, particularly in relation to the electrification of heating.

These peak loading scenarios could then be used to as inputs to assessment of the viability of commercial solutions to delivering network capacity.

## 1.2 Methodology

The scenario methodology was based on combining scenarios for underlying demand (based on economic, demographic and efficiency factors) with additional impacts at peak related to new technologies such as electric vehicles, heat pumps and air conditioning. For Grid and primary substations, historic peak loading values in system-normal conditions were identified. These were adjusted both for the effect of metered generation and for weather conditions during an average winter peak. This provided the baseline peak loading.

Additional research was commissioned in the areas of electric heating and cooling (ie domestic heat pumps and air conditioning) as these are material sources of uncertainty in peak demand in the decades ahead. Potential interventions to alter domestic customer behaviour were researched and modelled to assess their impact on mitigating secondary network reinforcement requirements in load scenarios including domestic heat pumps.

Based on work with academics at the University of Manchester, a ‘real options’ approach was developed to inform cost-effective decisions on how much network capacity to deliver and when, given uncertainty in future peak demand. The chosen approach was tailored to DNO data and processes related to investment decisions for thermal capacity on Grid and Primary distribution networks, with the initial academic model further developed by Electricity North West.

## 1.3 Outcomes and Key Learning

For the Grid and primary network, this project has created a series of streamlined spreadsheets to generate a set of annual peak load scenarios consistently for each GSP, BSP and primary substation, both for summer and winter. The previous methodology to generate a single best-view forecast of observed demand has been replaced by the outcome of this project. Consistency in naming of substation sites and connectivity was key to delivery. For the secondary networks, load scenarios were delivered by updating Electricity North West’s Future Capacity Headroom model.

In each case the winter best-view scenario was broadly flat peak demand to around 2025, before growing slowly based on additional uptake of low carbon technologies. However importantly to network planning, local differences were reflected.

Six combinations of ‘heat pump-house type’ were identified as material to future uptake - 3 air source heat pumps (ASHPs) and 3 hybrids combining air source heat pump and gas boiler. Modelling of the thermal demand of the house and the operation of the heating system – building physics modelling - allowed heat pump demand profiles to be generated reflecting future control strategies and a range of external temperatures to be analysed.

Diversified half-hourly profiles were developed for the peak in an average winter and in an extremely cold winter occurring 1 in 20 years. Importantly they include the resistive electric back-up heaters which function at lower external temperatures. This highlighted that in a very cold winter, ASHP peak demand would double, whereas hybrid demand would be zero.

As distribution networks will increasingly provide heating, the project recommends that networks should be planned to meet peak demand even these ‘1 in 20’ temperature conditions, as is the case in gas network planning. Since future uptake of heat pumps is expected to be around 2/3 ASHP and 1/3 hybrid HP in the reference scenario, this change would make little difference in capacity requirements at the higher voltages. However planning for 1 in 20 winters would have a significant impact on required capacity on LV networks serving a cluster of ASHPs.

The inputs to the EA Technology Transform® model were adapted to explore the hypothetical impacts on loading of these 6 heat pump types on LV feeders and distribution substations in a generic distribution network. This indicated reinforcement requirements to address thermal and voltage issues using its generic network model. Analysis using Transform suggested that interventions to increase the home’s thermal insulation levels, over-size heat pumps and encourage hybrids could all be cost-effective ways to mitigate increases in LV reinforcement costs, but significant delivery challenges remain.

This work on heat pump profiles was further extended to explore how those profiles would change if the heat pumps operated more flexibly in response to price signals eg hybrids switching to/from electric to gas or lesser/ greater use of local heat storage. The signals could be given by any party in the electricity system with a business model to extract value from national balancing – distribution system operators, a national transmission system operator, suppliers or aggregators.  Higher peak values increased the local distribution network impacts and expected reinforcement requirements by 24%, as a consequence of following the national system balancing signals.

Working with the Tyndall Centre at the University of Manchester, the project explored additional cooling load from air-conditioning. By 2030 this could plausibly add 600 MW to summer peaks, so similar in scale to future heat pump load in winter (but without explicitly considering whether cooling and heating would be delivered by combined units or separately). Tyndall’s review however highlighted the limitations of the evidence base around air-conditioning, and the consequent difficulties for understanding future demand, its uncertainties and drivers.

The peak scenarios have been used as an input to a prototype ‘Real Options Cost Benefit Analysis’ (CBA) tool, which has been developed by Electricity North West as part of this project. The tool provides various cost and risk metrics to support decisions on what is the most cost-effective intervention to resolve thermal capacity constraints at Grid and Primary substations. The model was used to support a decision in 2016, where post-fault demand-side-response was chosen as the cost-effective alternative to traditional reinforcement of a primary substation. The RO-CBA has enabled transition to business-as-usual of an approach developed in the ‘Capacity to Customers’ LCNF trial.

## 1.4 Conclusions

Substation peak loading scenarios reflecting the range of demand uncertainty can be successfully delivered at all voltage levels on a distribution network. For the Grid and primary networks where substation metering exists, the project has demonstrated that is both feasible and material to correct historic peaks for local generation and weather-effects.

Furthermore, the RO-CBA approach can be used to identify when alternative solutions to network capacity are cost-effective, given the specific costs and demand scenarios for that site. This work has been recognised as academically and commercially significant, and is already influencing Electricity North West’s approach to strategic planning, and enabling a material reduction in expenditure.

However, the project has highlighted the limitations of restricting analysis to a single half-hourly value of seasonal peak demand as the sole input to network planning, given the variety in half-hourly profile characteristics of low carbon (demand) technologies, generation and different demand types. This wider challenge of generating adequate scenarios for strategic planning is now being addressed by Electricity North West’s NIA project ‘ATLAS’. This considers both half-hourly and seasonal behaviour, maximum and minimum, active and reactive power, and will include scenarios for metered and non-monitored generation affecting measured demand.

### 1.5 Closedown Reporting

This project was compliant with the governance for Network Innovation Allowance (NIA) projects, and so this report has been structured to meet these governance requirements. The structure and headings in this report reflect these requirements.

A version of this report - including only sections 2-6, 7.1, 8.1, 9.1 and 10-12 - is available via the Energy Networks Association's Smarter Networks learning portal at www.smarternetworks.org.

This version of the report provides additional information that is useful in understanding the project.

## 2 PROJECT FUNDAMENTALS

| | |
|---|---|
| Title | Demand Scenarios with Electric Heat and Commercial Capacity Options |
| Project reference | NIA_ENWL001 |
| Funding licensee(s) | Electricity North West |
| Project start date | April 2015 |
| Project duration | 18 months |
| Nominated project contact(s) | Rita Shaw (rita.shaw@enwl.co.uk) |

## 3 PROJECT BACKGROUND

*This section reproduces the 'Problem' and 'Method' as stated in the original project registration.*

There is significant uncertainty around the timescale and location of future changes in peak electricity demand on distribution network assets. Factors contributing to that uncertainty include economic changes, energy efficiency, alterations in customer behaviour (such as peak relative to average behaviour, response to smart metering and increased use of air conditioning), and adoption of low carbon technologies such as distributed generation, electric vehicle charging and heat pumps. Alongside future uncertainty, volatilities in past peak demand can make it difficult to understand the past baseline eg related to economic activity, generator output and weather-dependence, alongside measurement uncertainties.

Heat pumps offer huge potential for carbon savings once electricity is decarbonised. But we consider rising non-diverse electricity demand from heat pumps is the most significant and uncertain long-term (from RIIO-ED2 onwards) effect on demand on the distribution networks. This is due to limited adoption so far, and uncertainty about future incentives for deployment and during operation.

DNOs need to make assumptions about the timescales and location of demand growth so they can invest efficiently in network capacity. Existing methods of demand analysis and forecast do not capture and address this multi-faceted uncertainty in a structured way. So we think there is a need to reassess and improve how we understand uncertain electricity demand, particularly how this is affected by electric heat. Secondly given that uncertainty, further analysis is required around how to make decisions about investing for capacity, including assessment of the commercial options to release network capacity, which may be cheaper and quicker to deliver than technical solutions on the network.

This project builds on the previous IFI projects 'Demand Forecasts and Real Options' and 'Load Allocation', the First Tier LCNF project 'Low Voltage Network Solutions', the Second Tier LCNF project 'Capacity to Customers' and our internally funded 'Power Saver Challenge' and 'Demand and Generation Dashboard' projects.

It first involves Development and Demonstration of better *Technical* approaches to estimating current and future load by distribution network asset, reflecting the associated uncertainties in load. It will progress from a best-view forecast based on past observed demand, to a set of scenarios based on a corrected version of past demand.

These load scenarios are then the foundation for assessing two *Commercial* solutions to capacity problems. The project will Develop and Demonstrate a 'Real Options' approach to assessing when to use our 'Capacity to Customers' demand side management (DSM) technique versus various scales of traditional Grid & Primary reinforcement. The project will also do enabling Research on identifying and prioritising potential Commercial non-network solutions to address secondary networks constraints associated with uptake of domestic heat pumps.

# 4 PROJECT SCOPE

*This section reproduces the 'Scope' as stated in the original project registration.*

### A. Load Scenarios with Electric Heat

- Generate baseline and future scenarios of 'Grid and Primary' load with initial improvements to method (summer 2015)
- Develop disaggregated domestic heat pump scenarios – moving on from the single domestic heat pump type in the 'Transform' model to up to ten heat pump / house type combinations, and modelling how load profiles are affected by both thermal load and supplier/ system operator incentives – working with Delta-ee and Imperial College (end 2015)
- Improve our Future Capacity Headroom model and deliver an improved assessment of thermal and voltage constraints for the secondary networks including heat pump inputs (early 2016)
- Generate baseline and future scenarios of load at 'Grid and Primary' and secondary networks including various incremental improvements to inputs and method (summer 2016).

### B. Commercial Capacity Options (based on Load Scenarios)

- Definition of a 'real options' tool to support decisions on DSM versus various scales of 'Grid and Primary' reinforcement under demand uncertainty, based on an approach developed with the University of Manchester.
- Identification and prioritisation of intervention options beyond the customer meter to address secondary networks constraints. For example, would incentivising thermal stores or insulation be more cost effective than network reinforcement?

This project is innovative because no other DNOs has developed this type of granular analysis of uncertain demand, or investigated these commercial approaches to capacity issues.

# 5 OBJECTIVES

*This section reproduces the 'Objectives' as stated in the original project registration.*

The financial benefits of the project will come from ensuring that load-related investment is well justified, and in particular by identifying where the 'Capacity to Customers' DSM technique or customer interventions beyond the meter can be used to avoid or defer load-related investment. This will be done by more accurately and credibly representing current and future load, to minimise load-related expenditure to deliver only the justified capacity.

It will also provide the foundation for future use of commercial solutions where these can be shown to provide an overall cost benefit. These commercial solutions also offer the opportunity to release capacity more quickly than traditional network solutions (customer service benefit), and with lower environmental impact e.g. reducing electricity demand, avoiding embedded carbon associated with new network assets. It is also expected that the project will streamline analysis of demand in the planning process, allowing our engineers to take a more sophisticated view of current and future demand, without an increase in planning engineer resource.

# 6 SUCCESS CRITERIA

*This section reproduces the 'Success Criteria' as stated in the original project registration.*

### A. Load Scenarios with Electric Heat

- Appropriate methods implemented to correct observed past Grid & Primary peak demand for weather effects and distributed generation contribution, balancing accuracy with cost.
- Enhanced quantification of impact of growth of electric heating in 2022 and 2030 on the Electricity North West network under different scenarios – using analysis of different types of heat pumps in different housing types. High-level analysis of a provisional scenario to 2050.
- Quantification of how other electricity value chain players' influence of electric heating operation will affect this impact (either reducing the impact and / or increasing the impact at different times) in 2022 and 2030, with high level view to 2050.
- Revised tools and methods available to generate credible Grid & Primary and secondary networks peak load scenarios by asset to 2030, reflecting the scale and sources of uncertainty in demand, with scenarios used for internal and external business requirements.

### B. Commercial Capacity Options

- Created a 'Real options' decision approach with supporting Excel tool(s), supported by the University of Manchester's analysis, which uses demand scenarios to make an economic assessment of whether to use the Capacity to Customers post-fault DSR method versus traditional reinforcement.
- Identification, initial assessment and ranking of ways that Electricity North West can mitigate (other than reinforcing the network) the impact that electric heating will have on their network (focusing on the customer side of the meter).

# 7 PERFORMANCE COMPARED TO THE ORIGINAL PROJECT AIMS, OBJECTIVES AND SUCCESS CRITERIA

## 7.1 Summary of Performance for Smarter Networks Portal

The project has addressed all of the success criteria identified in the initial registration.

The scenario methodology was based on combining scenarios for underlying demand (based on economic, demographic and efficiency factors) with additional impacts at peak related to new technologies such as electric vehicles, heat pumps and air conditioning. For the Grid and Primary substations, historic peak loading values in system-normal conditions were identified and adjusted both for the effect of metered generation exporting to the network and for average winter peak weather. This provided the baseline peak loading.

Additional research was commissioned in the areas of electric heating and cooling as these are material sources of uncertainty in peak demand in the decades ahead for winter and summer peaks – specifically domestic heat pumps and air conditioning. The effects of heat pumps operating as normal or flexibly in response to national price signals were assessed for their impact on the reinforcement cost of the secondary networks. Potential interventions to alter domestic customer behaviour were researched and modelled to assess their impact on mitigating secondary network reinforcement requirements in load scenarios including domestic heat pumps.

Based on work with academics at the University of Manchester, a ‘real options’ approach was developed to inform cost-effective decisions on how much network capacity to deliver and when, given uncertainty in future peak demand. The chosen approach was tailored to DNO data and processes related to investment decisions for thermal capacity on Grid and Primary distribution networks, with the initial academic model developed iteratively by Electricity North West.

Full details of this development work can be found in the closedown report on the Electricity North West website. For completeness, the report covers developments achieved both in the NIA project ‘Demand Scenarios with Electric Heat and Commercial Capacity Options’ and in the forerunner IFI project ‘Demand Scenarios and Real Options’ which laid the groundwork for the approach to peak scenarios and real options.

*Information in the following sub-section does not appear in the summary report on the Smarter Networks Portal.*

## 7.2 Mapping of Success Criteria to the description of outcomes in Section 8

The following table indicates where the reader can find the description of work for each of the success criteria.

| A. Load Scenarios with Electric Heat | Described in |
|---|---|
| 1) Appropriate methods implemented to correct observed past Grid & Primary peak demand for weather effects and distributed generation contribution, balancing accuracy with cost. | 8.3 |
| 2) Enhanced quantification of impact of growth of electric heating in 2022 and 2030 on the Electricity North West network under different scenarios – using analysis of different types of heat pumps in different housing types. High-level analysis of a provisional scenario to 2050. | 8.4a and 8.4b |
| 3) Quantification of how other electricity value chain players’ influence of electric heating operation will affect this impact (either reducing the impact and / or increasing the impact at different times) in 2022 and 2030, with high level view to 2050. | 8.4c |

| | |
|---|---|
| 4) Revised tools and methods available to generate credible Grid & Primary and secondary networks peak load scenarios by asset to 2030, reflecting the scale and sources of uncertainty in demand, with scenarios used for internal and external business requirements. | 8.5, 8.6 and 8.8 using 8.2, 8.3 and 8.4 |
| **B. Commercial Capacity Options** | |
| 1) Created a 'Real options' decision approach with supporting Excel tool(s), supported by the University of Manchester's analysis, which uses demand scenarios to make an economic assessment of whether to use the Capacity to Customers post-fault DSR method versus traditional reinforcement. | 8.7 |
| 2) Identification, initial assessment and ranking of ways that Electricity North West can mitigate (other than reinforcing the network) the impact that electric heating will have on their network (focusing on the customer side of the meter). | 8.4d |

# 8 THE OUTCOME OF THE PROJECT

## 8.1 Summary of Outcome for Smarter Networks Portal

A methodology and tools were developed to produce peak loading scenarios for each substation on the Electricity North West network.

For GSP, BSP and primary substations, these were annual scenarios of seasonal peaks of 'true' demand to 2030/31. These scenarios were used in a prototype 'Real Options' model, developed to support decisions on whether it will be most cost-effective to provide capacity by traditional reinforcement or by post-fault demand-side-response, and quantifying associated network risks.

An initial version of the methodology and streamlined spreadsheet tools for the Grid and Primary network were applied to deliver winter peak scenarios in 2015. In 2016, both winter and summer peak scenarios were delivered with revised inputs. The historic peak loading values in system-normal conditions were adjusted for the effects of metered generation exports and weather-corrected to average winter conditions. Both these effects were shown to be material relative to the scale of annual change in peak demand.

The methodology to generate peak demand scenarios was based on combining an underlying view of changes in demand (based on economic, demographic and efficiency factors) with additional impacts at peak related to new technologies. These incremental technologies included electric vehicle and heat pump in winter, and electric vehicle and air conditioning in summer. Underlying demand scenarios reflected the demographic and economic situation for the 35 local authorities served by Electricity North West. The heat pump and air conditioning scenarios reflected new analysis commissioned for this project.

Four scenarios were developed in detail – Best View, Active Economy, Focus on Efficiency and Green Ambition – reflecting plausible combinations of the underlying and incremental components.

Working with Delta-ee, the project developed new insights about the scale of future load from domestic heat pumps, developing uptake scenarios and half-hourly profiles for seven heat pump-house type combinations - 3 air source heat pumps (ASHPs), 3 hybrids combining air source heat pump and gas boiler and then subsequently a ground source heat pump, both for the peak in an average winter and in an extremely cold winter occurring 1 in 20 years. Modelling of the thermal demand of the house and the operation of the heating system – building physics modelling - allowed heat pump demand profiles to be generated reflecting future control strategies and a range of external temperatures. Additionally, an approach was developed to create diversified profiles across multiple customers using a distribution network.

The evening peak of the profile was an input the peak scenarios for Grid and Primary substations. Using the complete profiles, the impacts on the LV feeders and distribution substations were explored using the Transform® generic distribution network model, which indicated reinforcement requirements to address thermal and voltage issues. Interventions with customers to increase a home's thermal insulation levels, over-size heat pumps and encourage hybrids could all be cost-effective ways to mitigate increases in LV reinforcement costs, but significant delivery challenges remain.

This work on heat pump profiles was further extended to explore how those profiles would change if the heat pumps operated more flexibly in response to price signals eg hybrids switching to/from electric to gas or lesser/ greater use of local heat storage, based on price signals from electricity suppliers or system operators reflecting national system balancing needs. Higher peak values in the heat pump profile increased the local distribution network impacts and reinforcement requirements, as a consequence of following the national system balancing signals.

Working with the Tyndall Centre at the University of Manchester, the project identified that additional summer load from air-conditioning could by 2030 be as significant in scale as heat pump load in winter. Tyndall's review also highlighted the limitations of the evidence base around historic uptake and profiles of air-conditioning usage, and the consequences of this for understanding future demand.

The peak scenarios have been used as an input to a prototype 'Real Options Cost Benefit Analysis' tool, which has been developed by Electricity North West as part of this project. The tool provides various cost and risk metrics to support decisions on what is the most cost-effective intervention to provide capacity on the Grid and Primary network. The prototype has already been successfully deployed to inform investment decisions.

Consistent with the winter peak scenarios developed for the Grid and Primary network in 2015 and 2016, scenarios of observed winter peak loading in 2022/23, 2030/31 and 2050/51 were also developed for the secondary networks (HV feeder legs, distribution substations). This was done using new runs of Electricity North West's proprietary Future Capacity Headroom model, indicating the scale and uncertainty in future volumes of interventions on the secondary network.

*Information in the following sub-sections does not appear in the summary report on the Smarter Networks Portal.*

## 8.2 Analysing historic peak loadings for the GSP, BSP and primary substations

Two important effects on network loading per substation have been accounted for as part of the project – local generation export and winter weather effects – in order to produce a more representative view of peak loading as the historic baseline for generating peak demand scenarios in this project.

### Considering exporting generators in the estimate of true demand

SCADA data on half-hourly average measured substation loading has been combined with the network connectivity of generators and their half-hourly metered export to the network (for the larger generators with such metering installed as part of the supply contract). Exporting generators on a demand-dominated substation suppress measured demand – so a truer view of demand can be gained by combining measured demand and metered export. This indicates the 'monitored component of true demand', referred to in the rest of this document as 'demand' or 'true demand'. In addition to metered export, the effects non-metered export of generated electricity and suppression of net consumption at customer premises by generation will also suppress measured demand. These additional effects of generation to the network were not considered in this project, but are being addressed in the ATLAS project. www.enwl.co.uk/atlas.

Care must be taken in interpreting results for generation-dominated substations where generation may be larger that true demand, as if there is no sign convention on the metering data this may not reliably indicate when measured demand is a reverse power-flow due to generation.

A system to combine and process this half-hourly metering data was initially set up for the Electricity North West network in early 2015 in a Microsoft SQL server system named the ‘Demand and Generation Dashboard’ or ‘Dashboard’, funded outside of the NIA project.

**Identification of peak values**

From the half-hourly data outputs of the Dashboard, system-normal peaks of true demand then needed to be identified for every substation. This was done by identifying the MW peak and then finding the MVA value at the corresponding time. In 2015 and earlier, this was done manually by planning engineers, funded outside of the Demand Scenarios NIA project.

In 2016, this manual effort was supplemented by an initial version of the data processing methodology being developed in the ATLAS project, with manual validation of the results obtained. This efficiency from automation allowed both summer and winter peaks to be identified for the first time in 2016, and provided an important practical test and review opportunity for the methodology being developed in ATLAS. The ATLAS project will further refine the approach for processing of half-hourly data to system-normal conditions – addressing switching actions, missing data, spikes and erroneous readings.

The NIA project has then used, reviewed and adapted the historic peak demands identified the half-hourly presented by the Dashboard system. As an example[1] of the scale of difference between measured and true demands in 2015/16, the aggregate of the *measured* peak demands[2] across 65 individual Bulk Supply Points on the Electricity North West network was 4,128 MVA, which had been suppressed by 188 MVA by the effect of exporting generators at those times of peak.

True demand was thus around 4.5% higher than measured demand. Notably this effect is not evenly spread across substations, but depends on the location of generators. The scale of this effect increases as more large generation is connected to the distribution networks, so it is increasingly important that DNOs have systems and processes to assess true demand.

**Simple winter weather correction**

Winter peak demands can be expected to be lower in a mild winter and higher in a cold winter. Given the desire for consistency with National Grid’s approach to reporting requirements for the Grid Code and simplicity in implementation, the approach chosen was to correct (winter) peak true demands in each year by the ratio of National Grid’s Average Cold Spell (ACS) transmission demand for Great Britain, and the actual peak demand for Great Britain. ACS can be simply considered as a median value for demand across the expected temperature range[3].

Over the past 13 years, the ACS correction has ranged from a -4% to a +3% correction in peak demand, and thus the scale of this correction could be of the order of ±200 MVA but in a typical year is of the order of ±100 MVA spread across the whole network. Figure 1 demonstrates how neglecting weather corrections for the period from 2003 to 2008 would mask the underlying reduction in measured peaks over that period, and that neglecting to weather correct in more recent (warm) years would lead to an underestimate of underlying demand.

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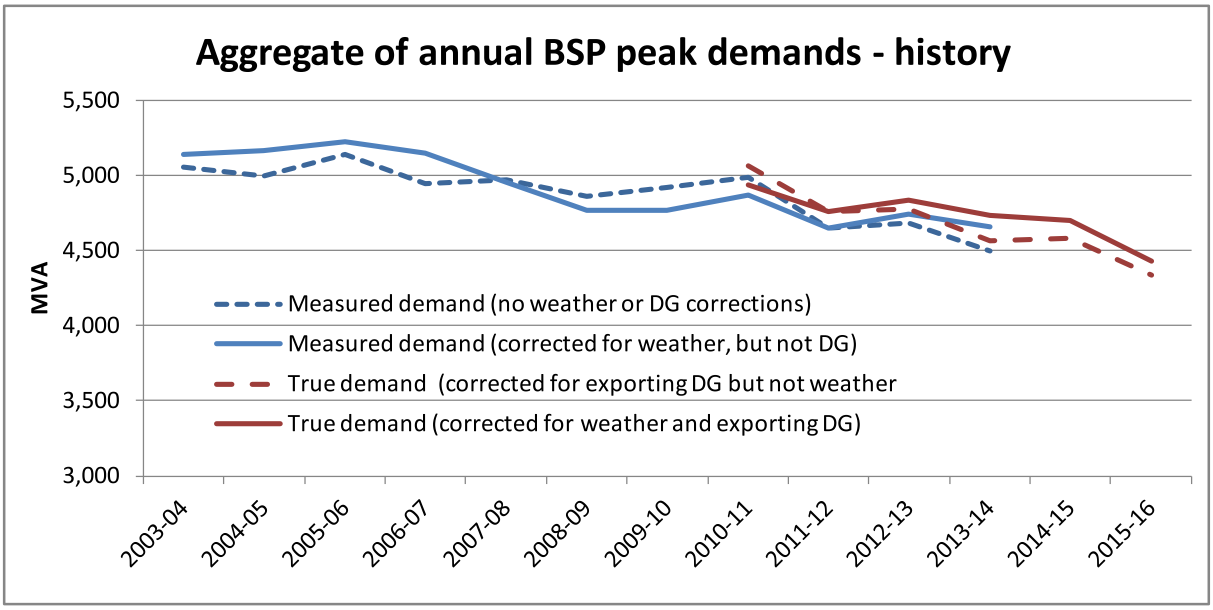
[1] 2016 Reinforcement Load Index report to Ofgem, as part of the Regulatory Reporting Pack.

[2] The sum of peak MVA per BSP, not the simultaneous peak of the network as a whole.

[3] https://www.emrdeliverybody.com/Lists/Latest%20News/Attachments/47/SC4L12%20ACS%20Methodology.pdf

*Figure 1: Historic aggregate peak including effect of applying National Grid's ACS factor*




In 2015/16, exporting generation suppressed measured BSP peaks by 4.5% on average, but the impact is localised so more important on particular substations. The correction to median winter weather has an additional effect in the range of ± 4% across substations, varying between years. Thus both corrections are significant in size in any given year, given that the average annual reduction in aggregate peak demand over the last 13 years was of the order of 1% per year. This validated that it was relevant to consider both these factors in identifying historic peak loading.

It was recognised that applying a single winter correction factor per year for each network asset neglects local differences in date of peak per asset, mix of load types and regional weather variations relative to the national position. So weather data purchased for other business needs was loaded into the Demand and Generation dashboard and an initial investigation of correlations between temperature and half-hourly loading data was completed with a view to developing a more tailored correction. This highlighted that a more sophisticated approach would be required than could be delivered in the Demand Scenarios project with its focus on peak behaviour. Thus further investigation of weather corrections was transferred to the scope of the ATLAS project.

### 8.3 Differences in underlying load trends

The underlying or background component in the methodology reflects the impacts on electricity demand from economic, demographic and efficiency factors, including local variations.

For BSPs, a reliable five-year history of true peak MW loading was established as described in the previous section, correcting for the effects of generation exporting to the network served by that BSP, and correcting for any variation in weather conditions compared to National Grid's view of median winter via their national 'Average Cold Spell' correction for that year. A future trend was then established using linear regression of the MW peaks, and converted to a normalised trend. If a primary had been transferred between BSPs within the period, the linear regression was adjusted accordingly. The relationship between MW peak and the associated MVA value in the base year i.e. associated power factor and reactive power component, was assumed to continue into the future.

The normalised peak trend was then combined with normalised trends derived from econometric analysis as described below. The BSP peak trends reflecting local factors were only used to influence the demand forecast for two years ahead – after this time the econometric factors were expected to dominate.

For primaries and the secondary networks where a reliable peak demand history was not available, the peak value in the base year was established by the methodology described in the previous section, but then econometric trends rather than a peak trend were used.

### Econometric input

Underlying econometric change in customers' energy demand at peak is based on update of work produced by the consultants CEPA in 2012, 2013 and March 2015, prior to this NIA project. This work had developed an economic model of electricity demand based on analysis of historic data. This included, both data from Electricity North West such as customer numbers and units distributed (adjusted to avoid excluding IDNO customers) and external data such as the Office for National Statistics projections of household numbers per local authority.

Statistical tests in the original work by CEPA had identified that electricity prices and energy efficiency as relevant drivers of demand in both the non-domestic and domestic sectors, with household formation and income also relevant for domestic sector and economic activity levels relevant for the non-domestic sector. CEPA produced a set of scenarios of units distributed to LV and HV customers, split domestic and non-domestic and per local authority, and further factors to estimate the effect on peak and how this would be affected by smart metering.

A key message of the analysis was the importance of energy efficiency in suppressing demand growth which would have otherwise occurred. The domestic and non-domestic trends per local authority from CEPA were then converted to normalised trends per BSP.

The updates to this work in the NIA project in 2016 included switching to a central scenario matching the Office of Budget Responsibility's central long-run economic growth rate (from CEPA's Central Scenario to Stalled Economy scenario, due to the downward revision of the growth rate forecast from 2.5 to 2%, as published March 2016). The normalised trends were also updated for latest information on units distributed to domestic and non-domestic customers in 2014/15 and 2015/16, and the estimated effect of domestic PV on suppressing units distributed.

The central scenario suggests a slight rise in demand in the next few years, followed by a slow fall to 100 MW below current levels by 2030. The incremental effect of load from new technologies such heat pumps, electric vehicles, and air conditioning is then added to this underlying trend. The next section describes work on characterising domestic heat pump demand at peak, and section 8.5 describes how the underlying and incremental loads are combined.

## 8.4 Analysis of domestic heat pumps adding to winter peaks

In scoping this NIA project, Electricity North West had identified that the switch of domestic heating from gas boilers to heat pumps was the most significant driver of long-term winter peak demand in future decades. However this was based on a very limited evidence base in terms of heat pump uptake and load profiles (based on the inputs to Transform v4 – see section 8.4b for further information on Transform). Addressing this gap in the evidence base was a key part of this project, addressed via work with the consultancy Delta-ee.

### a. Development of profiles and uptakes

Delta-ee developed three scenarios for domestic heat pump uptake on Electricity North West's network to 2050:

- The 'Delta-ee reference scenario'. This is Delta-ee's reference forecast for heat pump uptake, and represents what they believe will happen in reality.
- The 'high' scenario. This scenario aligns with the DECC high heat pump uptake rate (used in Transform), referred to as the 'DECC 1' scenario.
- The 'low' scenario. This scenario aligns with the DECC low heat pump uptake rate (used in Transform), referred to as the 'DECC 4' scenario.

*Figure 2: Scenarios of domestic heat pump uptake*

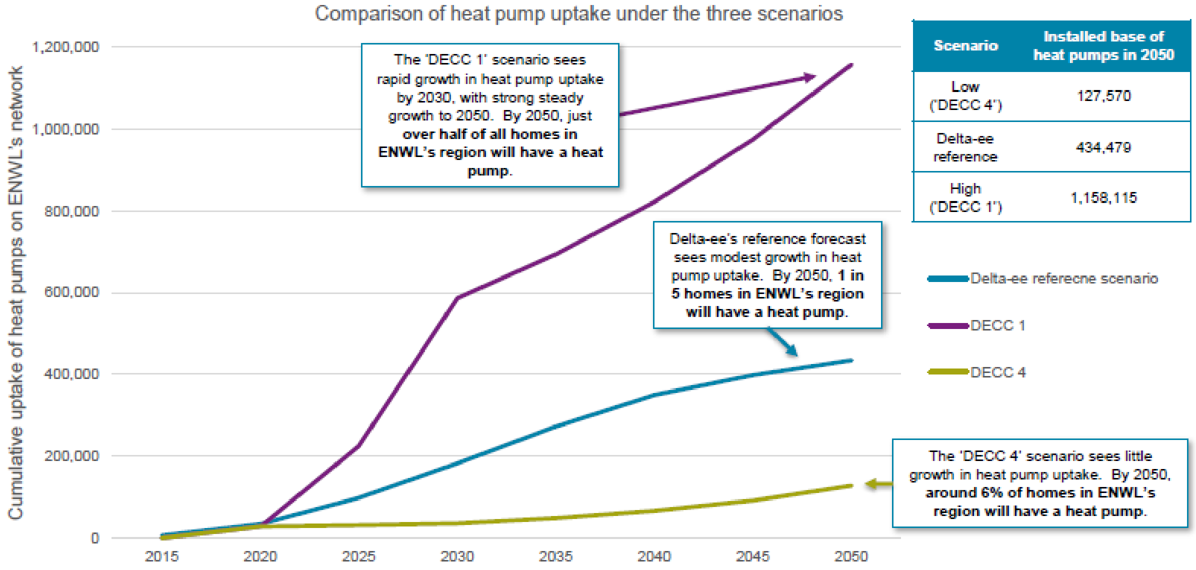



Figure 2 above shows these scenarios in terms of their cumulative uptake, with acceleration in deployment after 2020.

The reference scenario was developed based on assumptions around government policy tightening building regulations from 2021 onwards, slow cost reduction and efficiency improvements associated with technological development, limited customer or installer awareness until after 2020, with gradual introduction of new products and HP-specific electricity supply tariffs after 2020. These assumptions are detailed in Table 1. The detailed scenarios were split by 'heat pump-house type' and by local authority, informed by a review of the mix of housing stock in the Electricity North West region and its suitability for different types of heat pumps (typical of Great Britain).

*Table 1: Assumptions behind the reference uptake level*

**Policy**

**'Electrification of heat' ambition remains, but is delayed**

- Renewable Heat Incentive reduces gradually in the next few years to 2020, and disappears completely by 2026.
- New build regulations do not tighten until 2021/22, at which point ASHPs become the base case in off-gas dwellings. Gas boilers are banned from new builds in 2030 to accelerate uptake of heat pumps post 2030.
- Insulation in retrofit is the 'low cost' option that policy makers focus on for savings energy and reducing carbon emissions.
- 2020 RE & carbon targets are missed. Commitment to hitting 2050 targets remains, but are only met close to 2050.

**Technology**

**Slow growth in heat pump sales results in gradual cost reductions**

- Heat pump manufacturer and boiler makers continue to offer HP solutions and gradually add hybrids to their portfolio.
- Fully installed prices still fall quickly in the short term as installer skill improves, but more slowly in the longer term as uptake post 2020 is low.
- Efficiency still gradually improves due to technology performance improvements coming from Asia / Germany, and as system design, insulation levels of buildings and lower temperature heat distribution systems become more common.

**Customers and installers**

**Customer awareness remains low until 2020 with installers favouring low cost gas boilers until 2025**

- No real change in customer awareness & attitude until 2020 at which point building regulations drive the awareness and trust in heat pump technology.
- Customer confidence in policy / incentives for 'low carbon' remains low following a sharp reduction in FiT for PV and a small reduction in the RHI in 2016.
- Installers remain cautious about investment in training to install heat pump technologies, and continue to focus on offering customers boilers until 2020 - 2025.

**Industry 'push'**

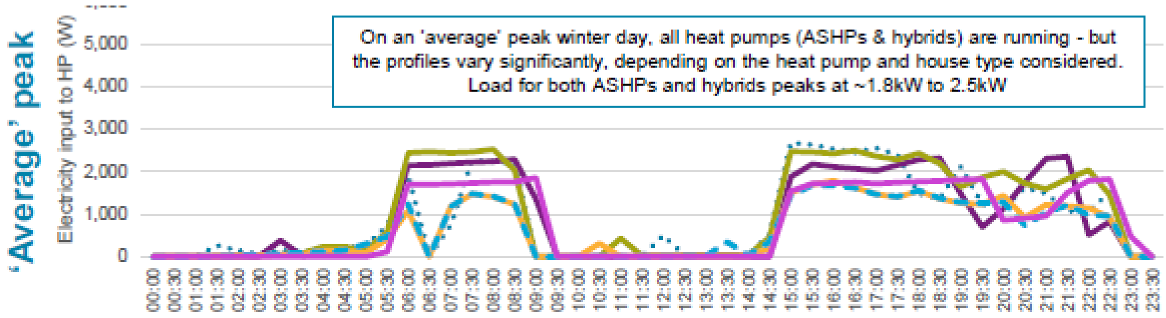
**Appliance manufacturers gradually add new product to their portfolios by 2020, with electricity suppliers getting more active post 2020**

- Boiler manufacturers are slow to add new heat pump products to their portfolio (except for Ideal via Atlantic), especially after the poor uptake of hybrid heat pumps experienced in 2014/15.
- Heat pump manufacturers continue to introduce more product to the UK, but are more cautious about the opportunity in the UK market following revisions in the RHI.
- Electricity suppliers introduce heat pump electricity tariffs post 2020 to help stimulate uptake of HPs.

Electrification of heat using heat pumps will increase winter electricity demand by around 2.5kW – 5.5 kW per household, depending on the 'heat pump - house type' and external temperatures. Six combinations of 'heat pump-house type' were identified by Delta-ee as material to future uptake - 3 air source heat pumps (ASHPs) and 3 hybrids combining air source heat pump and gas boiler.

Appendix 1 presents the heat pump types considered in detail in the project, while Appendix 2 presents the final report of project. Figure 3 overleaf shows how heat pump impacts can be expected to vary based on the different 'heat pump - house types' which that network serves.

*Figure 3: Diversified heat pump load profiles serving two heating periods on an average peak day in winter*

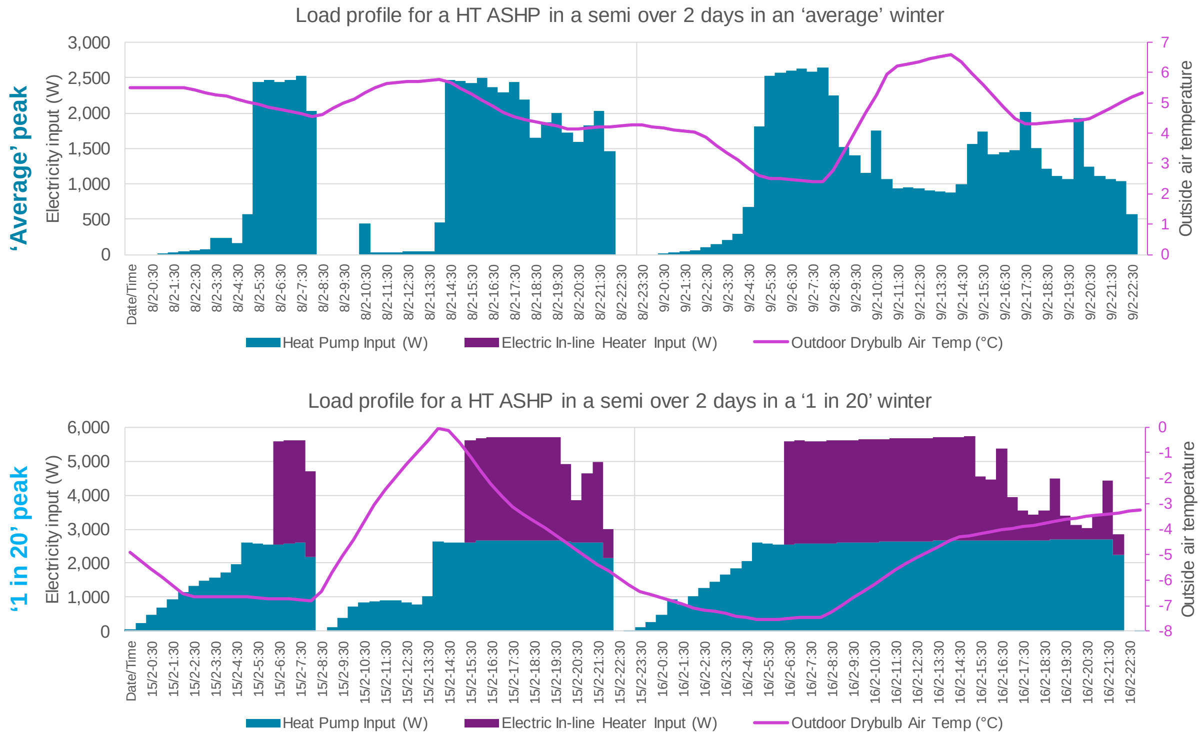



The approach taken to generate the profiles was to build thermal models of a type of house, its thermal demand, external temperature and how this would be served by its heating system (in DesignBuilder, a software tool for assessing building performance), in order to determine the electrical demand of the heat pump. This building physics modelling approach allowed future control strategies and a range of external temperatures to be analysed, and the results were sense-checked with a network of manufacturers, before the profiles were diversified to indicate their network impacts. This was a challenging modelling exercise, but delivered the expected outputs.

The impact of X customers is not simply X times the profile derived from the building physics modelling. An approach to diversification was developed, which suggested diversity would be low at only 10-15% diversity in an 'average' winter peak, lower in a '1 in 20' winter. The diversified profiles are available at www.enwl.co.uk/demandscenarios.

Half-hourly profiles were developed for the peak in an average winter and in an extremely cold winter occurring 1 in 20 years. This highlighted that comparing a typical winter peak day with sub-zero temperatures versus an extremely cold winter with an averaged daily temperatures below minus 5°C, ASHP peak demand (including the resistive electric backup) would double the diversified demand e.g. from 2.2 kW to 5.5.kW as shown in Figure 4 overleaf. There is minimal diversity at low temperatures, so this is a very significant load for LV networks designed for an after-diversity-maximum-demand of around 1-1.5 kW.

*Figure 4: Example load profiles for heat pumps: Higher temperature ASHP in a semi on 2 days in an 'average' winter & 2 days during a '1 in 20' winter*




As distribution networks will increasingly provide heating, the project recommends that networks should be planned to meet peak demand even in these '1 in 20' temperature conditions in unusually cold winters. This is currently the case in planning gas networks which currently serve heat demand. Planning for 1 in 20 winters would have a significant impact on required capacity on LV networks serving a cluster of ASHPs.

In a 1 in 20 winter, in contrast to ASHP, a hybrid HP would have an electrical demand of zero since the boiler would take over supply of heat. *This could mean that load on networks serving predominantly hybrids could be higher in an average winter than in a 1 in 20 winter*. Since future uptake of heat pumps is expected to be around 2/3 ASHP and 1/3 hybrid HP in the reference scenario, aggregated up to primary and BSP level, the incremental effect on peak load and capacity requirements is similar using the average peak and 1 in 20 peak profiles. This is shown in Figure 5 below, which combines the uptake numbers with the profiles, and is an input to understanding of the sensitivity of the network to different levels of heat pump penetration.

*Figure 5: The incremental peak load for electric vehicles and heat pumps which was used as input to the winter peak demand scenarios*

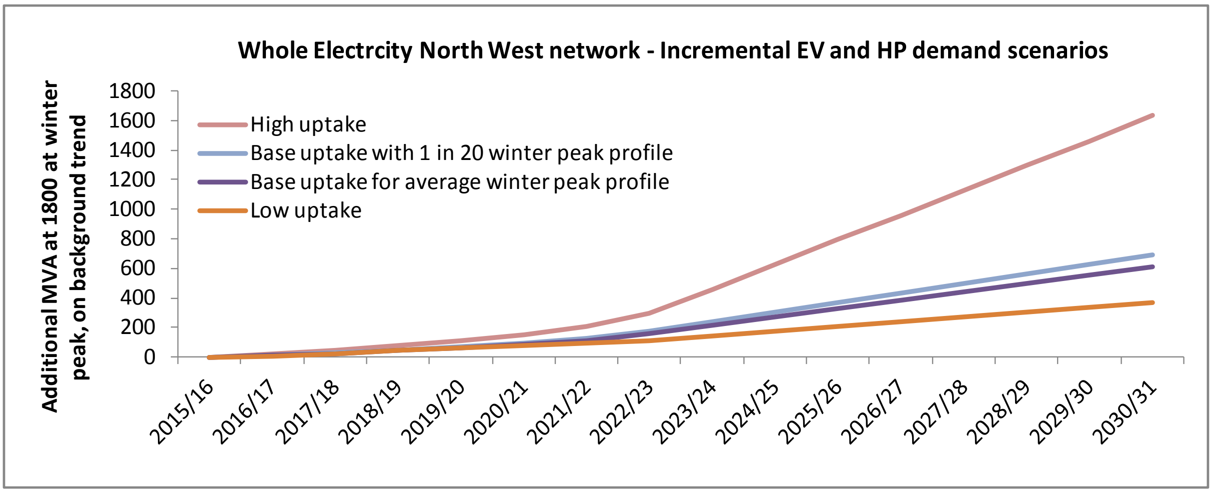
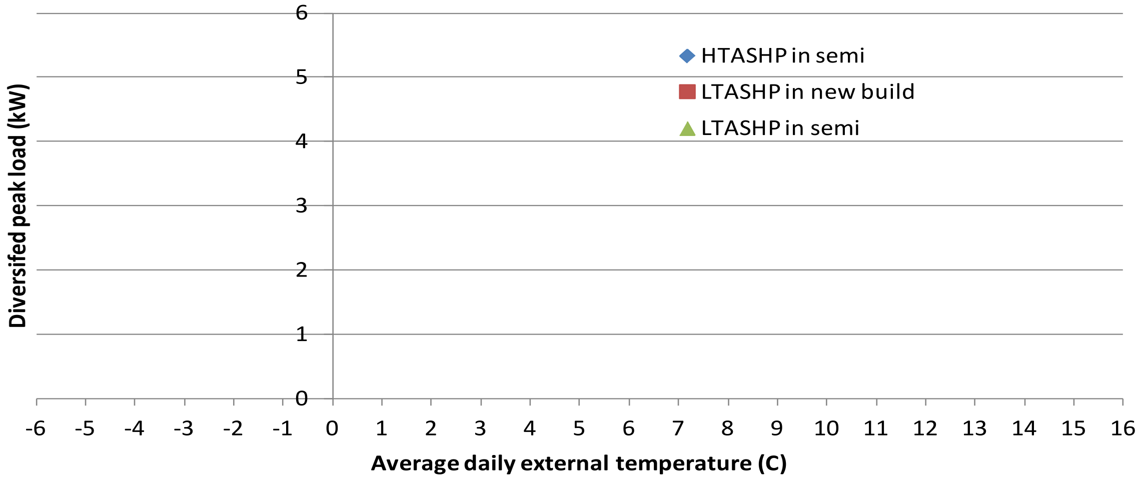


Figure 6 below shows the dependence of peak load on external temperature for ASHP – the building physics modelling was key to being able to derive such a relationship with temperature (the exact behaviour depending on other aspects of building occupancy and the profile of the temperature change over the day and previous day). These results will be used in the ATLAS project as part of the understanding of the monthly / temperature dependence of load from heat pumps.

*Figure 6: Dependence of diversified daily peak ASHP load on external temperature*




Combining the granular analysis of uptakes and profiles likely in Electricity North West's region by 2050 suggests additional peak loads of ~250 MW up to 3,500 MW, as shown in Table 2 below. For context, the current winter peak is around 4,200 MW.

*Table 2: Domestic heat pump uptake scenarios, showing additional peak load by 2050*

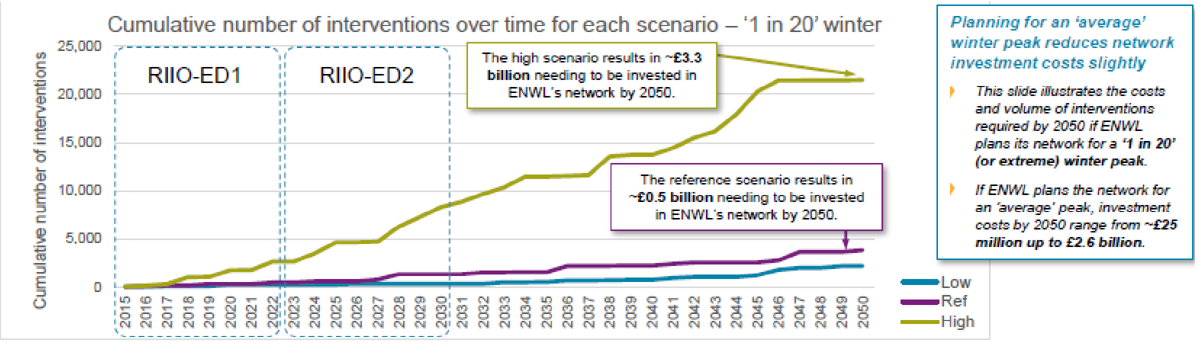
| Scenario | Share of homes with a heat pump | Additional network load on an 'average' winter peak | Additional network load on a '1 in 20' winter peak |
|---|---|---|---|
| Low | ~5% | 200 –300 MW | 400 –500 MW |
| Reference | ~20% | 800 –900MW | 1,400 –1,500 MW |
| High | ~50% | ~2,500MW | ~3,500 MW |

### b. Secondary network impacts via Transform

In 2012, under the direction of the Smart Grid Forum (DECC/Ofgem and industry), EA Technology created a generic model of GB system balancing and the GB distribution and transmission networks. This Transform® model could be used to answer high-level policy questions about smart grid transition and its costs. A 'network' version of this model – representing only the distribution network - can be tailored to the approximate scale and network types of an individual distribution networks. This allows high-level scenarios of loading to be compared against thermal and voltage capacity constraints, and total intervention costs to be estimated. Ahead of the RIIO-ED1 price control, Ofgem told DNOs to use Transform to complete part of their regulatory submissions on load-related investment requirements relating to the secondary networks.

Transform is a generic model of the network and cannot be set up to exactly match the actual population of network assets, with their connectivity and variations in capacity and loading level by asset, as is possible with Electricity North West's Future Capacity Headroom (FCH) model described in section 8.8. However unlike FCH, Transform extends to provide indicative costs of resolving both thermal and voltage constraints, and was easily adaptable to explore the hypothetical impacts on loading of the 6 heat pump types at minimal additional cost. This indicated reinforcement requirements to address thermal and voltage issues in the generic network model. Figure 7 indicates these across the three uptake scenarios (with the high scenario also simultaneously assuming high levels of electric vehicle uptake).

*Figure 7: Analysis using Transform of the number and cost of secondary networks interventions in different scenarios of heat pump uptake.*




| Intervention required if network is planned for a '1 in 20' winter peak | Low | Reference | High |
|---|---|---|---|
| **Cumulative number of network 'interventions' by 2050 per scenario** | **2,145** | **3,808** | **21,482** |
| *LV transformer upgrades (ground mounted & pole mounted)* | *1,346* | *1,754* | *6,607* |
| *LV underground works (major & minor)* | *799* | *2,054* | *14,865* |
| *Other* | *0* | *0* | *10* |
| **Total investment required for upgrading the LV network (£)** | **150 million** | **340 million** | **3.3 billion** |

Transform's approach thus had value for understanding order-of-magnitude impacts on secondary networks reinforcement costs. The next best approach to assess impacts on the network as a whole is to use the FCH. Detailed network modelling would provide more realistic outputs for specific locations but is not feasible for DNOs to deliver in a timely way, given the absence of complete validated models of their secondary networks (as demonstrated in the 'LV Network Solutions' project www.enwl.co.uk/lvns).

### c. Impact of other supplier or system-operator incentives

Delta-ee initially developed profiles of future heat pump demand for six 'heat pump-house type' combinations, based on meeting thermal demand with typical electricity / gas prices in a way which would be optimal for the individual customer.

This work on heat pump profiles was further extended to explore how those profiles would change if the heat pumps operated more flexibly in response to price signals. The signals could be given by any party in the electricity system with a business model to extract value from national balancing – distribution system operators, a national transmission system operator, suppliers or aggregators – anywhere in the value chain.

Collaborating with Imperial College, Delta-ee explored the potential consequences of optimising nationally versus at the customer level, for the specific case of domestic heat pumps operating flexibly. They identified that changes in the profiles increased peak loading on the network and the local distribution network impacts and reinforcement requirements, as a consequence of following the national system balancing signals. Optimising heat pump operation for national needs as opposed to at customer level could lead to a material increase in LV reinforcement interventions (by a quarter).

Heat pump operation can be '***flexible***' if its operation can be interrupted (i.e. switched off) for periods of time during the day, or if the timing of its operation can be moved to other times of the day (e.g. if there is a buffer tank, this can heated up earlier in the day to avoid operation of the heat pump during peak demand times). The three main factors enabling heat pump flexibility are the building's insulation, its thermal mass and the capacity of any existing buffer tanks: this flexibility would then be enabled by the intelligence of a control system and a market arrangement in which customers see a price benefit from flexible operation. A hybrid heat pump switching to/from electric to gas is another example of flexibility.

‘National’ electricity system players may influence heat pump load profiles in future, so the operation of the heat pumps would depend on short-term electricity price e.g. based on wind farm output and demand forecasts. In practice those signals for national balancing could come via multiple parties in the electricity system – a national system operator, supplier, aggregator or via a regional DSO who would also be considering local network impacts.

Imperial College modelled the national system, including analysis of potential flexibility of heat pump operation. This showed at times of low electricity prices, flexibility could increase peak loads by 5 –15% on ‘average’ peak winter days, and as high as ~25% on a ‘1 in 20’ peak winter day.

In the reference case for heat pump uptake, the cost of low-voltage network reinforcement on our network was estimated at £340m to 2050, but the number of required interventions would increase by 24% at an additional cost of £110m to provide sufficient network capacity for heat pumps operating flexibly in response to national signals. The impact would be even higher in a scenario for high uptake of heat pumps. At present this would be a socialised cost across all consumers, rather than being reflected back in the value chain to those being rewarded for flexible responses.

This is an example of how using the flexibility of heat pumps to meet a national balancing need may have unintended consequences and costs for other parts of the energy system. Similarly if heat pump flexibility were optimised just for local network balancing and network costs, that would lead to reduced distribution network costs but increased costs for national balancing. The assessment of the right objective for flexibility needs to consider the costs and benefits in the round – the research above has simply quantified that the distribution network cost impacts of national flexibility could be material.

### d. Potential for customer-side mitigating interventions

Whilst DNOs do not have control over heat pump uptake, they may be able to take customer orientated measures to mitigate the impact of peak loads. DNOs could work with customers to reduce peak loads from heating through measures such as reducing heating demands with efficiency improvements, incentivising installation of more efficient heat pumps, or different control and storage strategies, or using distribution pricing structures to limit adverse impacts from other parties (such as suppliers).

Table 3 lists the short-listed measures which were scoped in terms of scale and their impact on reinforcement costs using Transform. Full details are provided in Appendix 2 (page 80 onwards).

Measures A1 (insulation), B1 (over-sizing heat pumps) and C1(incentivising hybrids) appeared to be the most cost-effective in terms of implementation cost versus reduction in expected LV network reinforcement costs. However all of these present significant challenges for DNOs to trial and implement, particularly given the relatively small number of heat pump installations at present. Electricity North West is currently considering how and when to progress any of the presented customer interventions.

*Table 3: Customer-side measures investigated*

| No. | Customer side measure | Description |
|---|---|---|
| A1 | Additional insulation | Fund, support, or deliver insulation improvements to homes that are installing electric heating or heat pumps. |
| B1 | Larger heat pump to reduce direct electric heating | Subsidise the fully installed cost of heat pumps to encourage home owners to install a larger capacity unit – meaning more of the heating demand of the dwelling is supplied by the more efficient heat pump, rather than by the less efficient back up heater. |
| B2 | Higher efficiency heat pump | Subsidise the fully installed cost of heat pumps to encourage home owners to install systems with the highest |

| No. | Customer side measure | Description |
|---|---|---|
| | | COPs (or via supporting installer training to ensure high quality installations) –meaning the annual efficiency of heat pump system is higher. |
| C1 | Incentivise hybrids | Raise awareness of hybrids, provide cash-back type incentives for customers to install hybrids (or to retain their boilers). They could also compensate customers for 'lost' RHI revenue. |
| C2 | Self-generation micro-CHP | Raise awareness of micro CHP & provide cash-back type incentives for customers to replace boilers with micro CHP. |
| D1 | Shift heat pump operation with control strategies | Encourage the use of smarter controls and buffer tanks, provide cash-back type incentives for heat pump customers to install (larger) buffer tanks. This may require customer sacrificing some internal space for hot water tanks which the DNO could offer additional cash back / compensation for. |
| D2 | Shift heat pump operation with energy storage | Encourage the use of battery storage, provide cash-back type incentives for heat pump customers to install batteries. It could also compensate customers for signing-up to schemes allow the DNO to control/ influence battery operation (i.e. DNO demand response shifting). |

There will be additional costs for the implementation of the measures which could exceed the intervention savings. Some of these may be borne by the DNO where measures are directly implemented by the DNO, or the implementation costs might be delivered as part of wider regional or national programmes. It would be important for a DNO to coordinate activities with any external programmes to ensure there are no unintended consequences.

## 8.5 Delivering peak load scenarios for the grid and primary network

This section describes how the analysis of initial peaks was combined with underlying and incremental load trends to deliver a set of scenarios

### a. Methodology and spreadsheet tools developed

The naming of primary substations and BSPs in the scenarios was chosen to be consistent with that presented by Electricity North West in every section of its Long Term Development Statement (LTDS). Moving towards consistency with LTDS substation naming and connectivity was key to streamlined delivery of a set of scenarios.

Once the true weather-corrected peak MW and associated peak MVA had been identified for each primary, BSP and GSP as described in section 8.2, the peak scenarios were developed in the following stages – with one spreadsheet format for each stage.

1. Identify trend in winter peak MW at BSPs based on five-year history and linear regression, and generate normalised trend in peak per BSP
2. For each underlying scenario, convert the econometric trends in seasonal peak demand for the domestic and non-domestic sector for each local authority into normalised trends
    a. for each BSP, based on the local authorities of the primaries it serves, and its domestic v. non-domestic customer mix
    b. for each Primary, based on the domestic v. non-domestic customer mix in the local authority served.
3. For BSPs in winter, generate the underlying scenario trend via a weighted average of the peak trend and econometric trend in each of 3 scenarios (low, base, high). Otherwise the underlying scenario trend is based on the econometric analysis only.

4. Identify incremental load per primary in MVA at a specified time of day per season, in 3 scenarios (low, base high), based on the domestic v. non-domestic customer mix and the local authority served reflecting
    a. EV and HP in winter
    b. EV and AC in summer
5. Identify incremental load per BSP in MVA based on the aggregate of incremental load for the primaries it serves
6. For primaries and BSPs, generate a scenario set in MVA by multiplying the peak MVA by the normalised trend in underlying demand for the 3 scenarios, then add the incremental load for the 3 scenarios.
7. For GSPs, generate a scenario set based on the weighted average of the trend in BSPs served.

The above approach combines 3 underlying scenarios (low, base, high) with 3 scenarios for incremental load from new technologies (low, base, high), as shown in Figure 8 below. However nine scenarios was practically too many to consider in terms of their network impacts, is more than required to demonstrate the range of scenarios, and contains implausible combinations (e.g. low energy efficiency but significant investment in EV and HP). The set of nine was reduced to a set of four – representing plausible combinations and a reasonable range from high to low.

Spreadsheets were created which calculated and presented the scenarios for use in Strategic Planning:

- For a chosen scenario and season, the annual peak demands for all asset of a given type GSP, BSP, primary
- For a chosen asset and season, produce annual peak demands for all scenarios and graph – this provided an easy input to the RO-CBA model described in the next section.

*Figure 8: Nine potential scenarios based on combination of underlying and incremental components – reduced to four*

| | | | EV and HP | | |
|---|---|---|---|---|---|
| | | | Low | Base | High |
| | | | DECC 4 2014 (Low) | DELTA 2016 (Reference) | DECC 1 2014 (High HP) |
| Background including economic, efficiency, and peak behaviour | High 5% | CEPA's Strong Growth | | Active Economy 5% | |
| | Base 65% | CEPA's Stalled Economy, or Central Case, or Green Recovery | | BEST VIEW 65% | |
| | Low 30% | CEPA's Nothing but Green, or Green Transition | Focus on Efficiency 15% | | Green Ambition 15% |

Active Economy – As for BEST VIEW, but with a consistently higher economic growth rate above 3%, and minimal increases in energy efficiency – the highest demand in RIIO-ED1

Focus on Efficiency – As for BEST VIEW, but assuming increased government, commercial and consumer focus on energy efficiency, combined with a low scenario of domestic heat pump uptake – the lowest demand in RIIO-ED1.

Green Ambition – As for Focus on Efficiency, but instead with DECC/Ofgem's High views of uptake of electric vehicles and heat pumps – transitions from low to high demand by 2030.

Scenarios are produced as potential views of the future to be used as inputs to impact analyses; thus they do not necessarily need to have likelihoods assigned. However given the regulatory requirement for a best-view and the assumptions about economic and policy conditions associated with each scenario, there was a clear desire to comment on the relative likelihood of the scenarios.

The likelihoods are subjective, but based on an informed view of the underlying factors. The internal project steering group decided on the approximate likelihood of the best-view scenarios is 65%, with 5%, 15% and 15% respectively for the others, acknowledging that the true outcome is expected to be somewhere in between, and not a smooth trend.

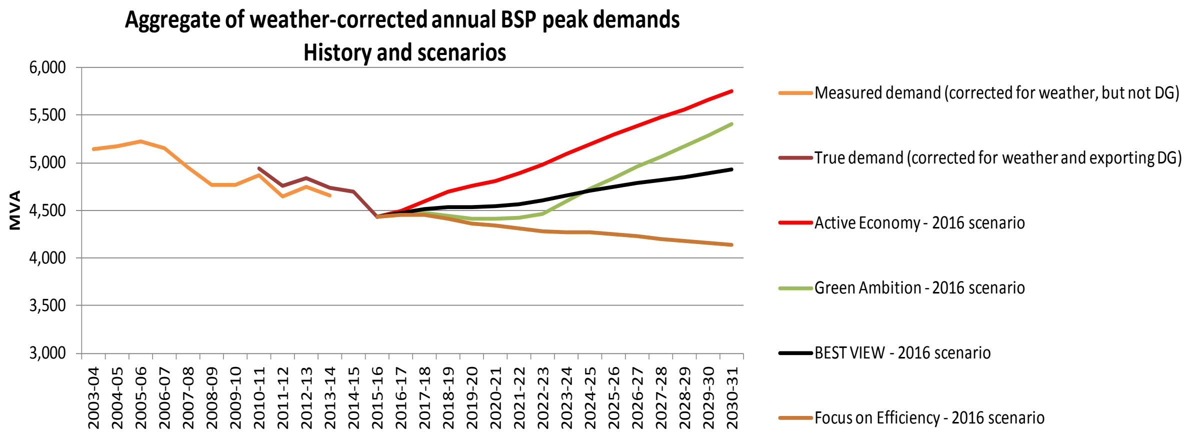
Depending on the decision-maker's attitude to commercial and network risk, the scenario likelihoods may or may not be used in interpretation of the output of the RO-CBA results described in section 8.7.

### b. The 2016 winter peak scenarios

An initial version of the methodology and streamlined spreadsheet tools for the Grid and primary network were applied to deliver winter peak scenarios in 2015. However this section presents just the 2016 peak scenarios, as representative of the learning in this project.

The best-view of the future of peak electricity demand is slow growth to 2030, but still not returning to 2005 levels by 2030. This is shown by the black line in Figure 9 below, which indicates the sum of measured peak demands at all Bulk Supply Points, adjusted both for the effects of large metered generators which export to the local network, and for 'average cold spell' weather conditions.

*Figure 9: Winter peak scenarios – aggregated across all BSPs*




The aggregate view above is the sum of the detailed scenarios produced for each substation, reflecting the local mix of domestic versus non-domestic customers, economic activity levels, and the likely uptake of electric vehicles and heat pumps in each area – so demand growth can differ significantly by area and by asset, growing more quickly in some areas than others eg Manchester and Ribble versus Cumbria. This means local interventions to add network capacity may be justified even with low growth in peak demand overall.

Although we have a best-view of peak demand out to 2030/31, there are multiple reasons for significant uncertainty about the future. So instead of one forecast, we create a set of plausible peak demand scenarios to reflect that uncertainty, as shown in the graph above.

**BEST VIEW** – Underlying growth in customers' energy demand at peak is based on the central view of underlying load growth. The incremental component associated with new technologies, based on the Low view from DECC/Ofgem of uptake of electric vehicles and of non-domestic heat pumps for the region, plus the Delta-ee reference scenario for domestic heat pumps, and latest data on the load profiles of electric vehicles and heat pumps. These new technologies are expected to add 600 MW of peak load by 2030 (200 MW from electric vehicles and 400 MW from heat pumps), with most of this occurring after 2023. The net effect with underlying demand is an overall increase in load of 500 MW above current levels by 2030.

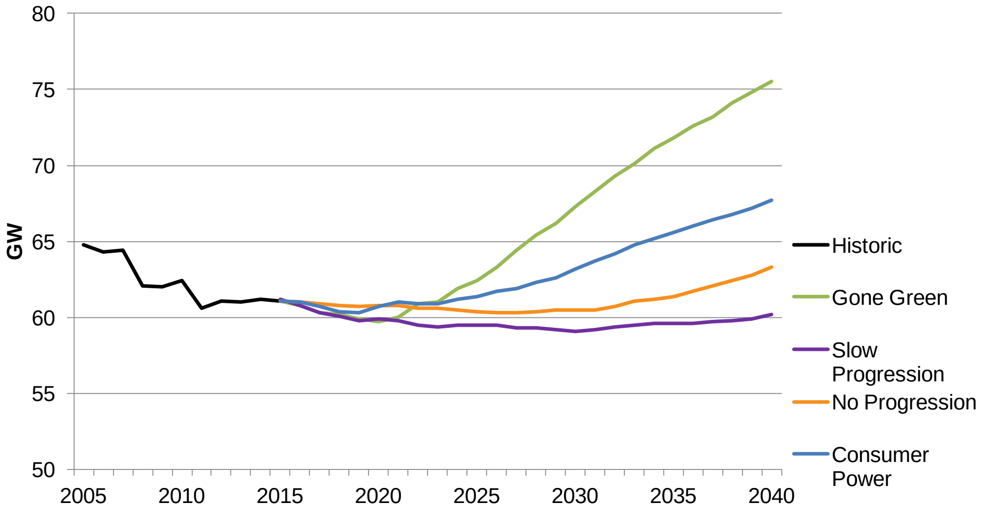
*Table 4: Uptake assumptions for Electric Vehicles and Heat Pumps*

| | Low Carbon Technology | 2022 | 2030 | Source of uptake level |
|---|---|---|---|---|
| **BEST VIEW** | Electric vehicles | 49,000 | 252,000 | DECC/Ofgem Scenario 4 'Low' |
| | Non-domestic heat pumps | 6,000 | 11,000 | |
| | Domestic heat pumps | 56,000 | 182,000 | Delta-ee Reference scenario |
| **GREEN AMBITION** | Electric vehicles | 148,000 | 593,000 | DECC/Ofgem Scenario 1 (medium EV, high HP) |
| | Non-domestic heat pumps | 7,000 | 16,000 | |
| | Domestic heat pumps | 74,000 | 587,000 | |

For the incremental component, the 2016 scenarios continued to use DECC/Ofgem's scenarios from the end of 2014 for uptake of electric vehicle and non-domestic heat pumps, as shown in Table 4. The non-domestic heat pump profile came from Transform v4. The profiles used were taken from the outputs of the LCNF 'My Electric Avenue' project. The electric vehicle uptake scenarios were still based on the late 2014 DECC/Ofgem numbers for the Electricity North West region, with the spread across the region based on DVLA data on electric cars per local authority and previous analysis by the Transport Research Laboratory for 2022 and beyond.

For comparison, National Grid published their 2016 Future Energy Scenarios in July 2016, after the peak demand scenarios in this project were finalised. Although the scenarios presented here are slightly different in structure, they are also structured to reflect differences in 'prosperity' and 'green ambition', similarly to National Grid's approach. Figure 10 shows their view of true) winter peak demand - weather corrected and not suppressed by distributed generation so comparable to true demand on our BSP network, although including demand at extra high voltages and directly on to the transmission network.

*Figure 10: Average cold spell peak demand for Great Britain, from Fig 3.1.11 of National Grid's Future Energy Scenarios 2016*




National Grid's analysis suggests little change in peak demand by the end of ED1 (2023) across GB, but further growth after that in all scenarios except Slow Progression. This hides significant local and regional variation, which our scenarios capture. The best-view peak scenario in this project is consistent with a view between No Progression and Consumer Power – both in terms of the underlying assumptions on economic growth and environmental ambition. This was a good comparative sense-check that the scenario work and best-view were credible. National Grid do not comment on the likelihood of their scenarios.

For the Grid and primary network, the previous methodology to generate a single best-view forecast of observed demand has been replaced by the outcome of this project, which has created a set of streamlined spreadsheets to generate a set of annual peak load scenarios consistently for each GSP, BSP and primary substation, for summer and winter.

### 8.6 Summer peak scenarios

This section describes the insights provided by the Tyndall Centre on the future impact of air-conditioning on electricity demand as part of the incremental component of peak load, and how this was then integrated in summer peak scenarios.

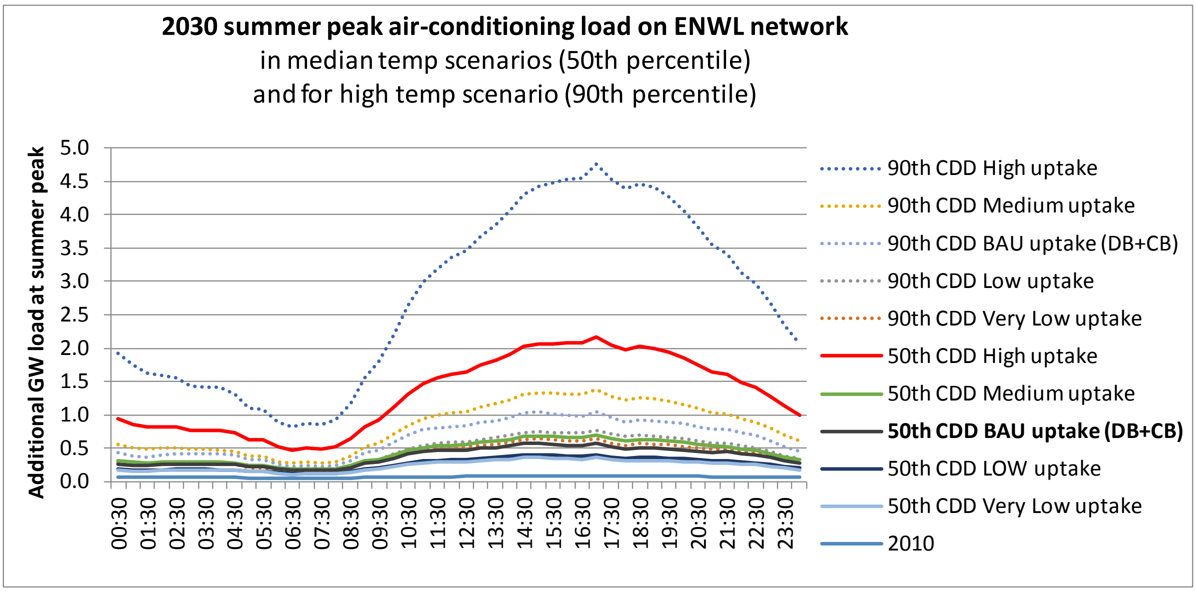
#### a. Academic analysis of the contribution of air conditioning units

Early results from the RESNET research project[4] had indicated the potential significance for the transmission network of future air conditioning load, particularly in the context of higher summer temperatures associated with climate change.

Working with the Tyndall Centre at the University of Manchester, the Demand Scenarios project sought to identify the potential scale and nature of impacts for the Electricity North West distribution network, without necessarily focusing on the extreme case as a test of network resilience. The impacts per primary substation were tailored to the mix of domestic and non-domestic load. The report on this work is provided as Appendix 3. Aggregated across the network, Figure 11 indicates the combination of different scenarios for additional domestic and non-domestic cooling and ventilation in summer peak in 2030.

[4] http://www.mace.manchester.ac.uk/our-research/centres-institutes/tyndall-manchester/major-research-projects/completed-projects/resnet

*Figure 11: Air conditioning load scenarios on summer peak day in 2030 for different expectations of Cooling Degree Days by climate scenario*




One of the key issues with summer peaks is time of day; this shows the importance of the new approach to scenarios in the ATLAS project - which addresses the full half-hourly load behaviour - rather than an arbitrary choice of peak time of day. This approach will be better able to reflect the shift in timing of additional load.

The University of Manchester completed a review of the evidence base on air conditioning demand, and demonstrated the significant uncertainty around the scale of future air conditioning demand, its variability by time and location across our network particularly amongst non-domestic customers with very diverse cooling needs. There is also potential for much higher uptakes and much higher additions to summer peak demands if climate change brings much raised temperatures.

In credible but unlikely scenarios, additional air conditioning load in summer could be several GW – comparable to current winter peak demand - if social practices, experience of heat waves (particularly in urban heat islands) and economies-of-scale in manufacturing costs led to significant deployment. Tyndall's review highlighted the limitations of the evidence base around historic uptake and profiles of air-conditioning usage, and the consequences of this for understanding future demand and its uncertainties.

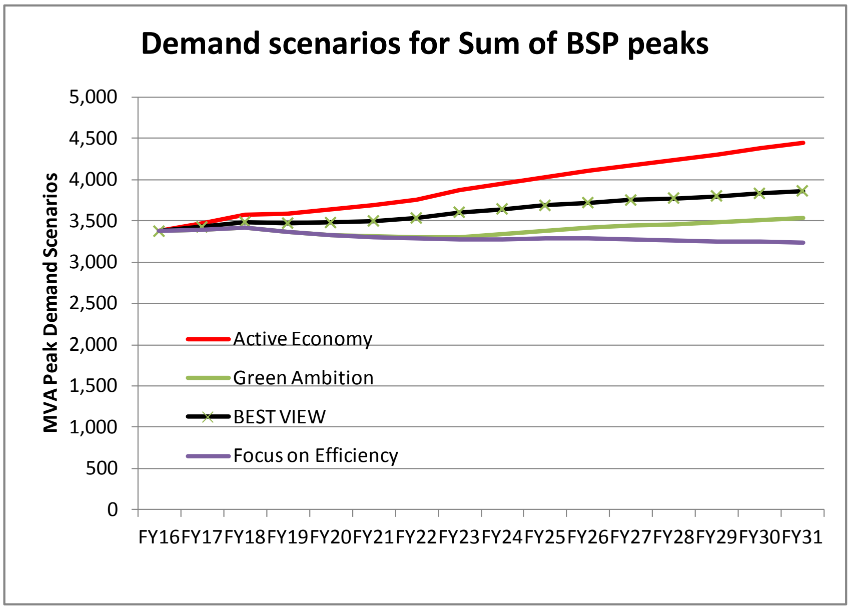
The work by Tyndall and DELTA on cooling and heat pumps was separate, and although both recognised that combined units exist to act as heat pumps and deliver cooling, there was no explicit consideration in the uptake scenarios as to whether cooling and heating would be delivered by combined units or separately, reflecting the differences and commonality in uptake drivers. This is a potential development area for the future.

### b. The 2016 summer peak scenarios

Scenarios of true demand at the summer peak were produced for the first time this year for all of Electricity North West's BSP and Primary substations, and used to assess which was the season of most onerous demand relative to capacity. Based on the assessment of peaks in 2015/16, summer had already become the season of most onerous demand relative to capacity for 7.5% of primary substations, but not for BSPs[5]. The aggregate of BSP summer peaks is shown in Figure 12 below.

[5] 2016 Reinforcement Load Index report to Ofgem, as part of the Regulatory Reporting Pack

*Figure 12: Aggregate of BSP summer peaks per scenario*




These summer scenarios are considered more uncertain that the winter scenarios for the following reasons:

- This is the first scenario of the contribution of air conditioning load to summer peaks on the distribution networks: the previous section highlighted the limitations of the evidence base.
- The underlying demand scenarios described earlier were initially created for the purposes of winter forecasting, then adjusted for summer by removal of smart metering time-of-use effects and adjusting for the uncertain effect of PV suppressing summer demand. The amount of PV was estimated from feed-in-tariff data for the region.
- The timing of summer peaks is variable through the day. Although the vast majority of substations have their winter peaks around 5.30-6pm, there is a wide spread of the time of day of summer peaks, with many peaking in daytime or overnight. Additional loads from electric vehicle, electric heating loads and air conditioning will be significant at summer, but they do not follow the profile of existing loads. This shows the importance of the ATLAS approach to demand scenarios which addresses the full half-hourly load behaviour, rather than an arbitrary choice of peak time of day.

Incremental load in summer was considered to include both electric vehicles and air conditioning. Contact with the My Electric Avenue project confirmed that summer profiles for electric vehicle charging were very similar to winter.

In terms of the incremental component of demand, the key change is to remove heat pump load and replace with air conditioning load. For the **Active Economy** and **Best-View** scenario, there was a modest uptake scenario which corresponded to 2.6% of domestic customers and 29% of commercial floor-space being air conditioned by 2030, and the likely usage profile based on median cooling requirements in our region at 6pm in the summer peak in 2030.

As in the winter case, these incremental components add around 600 MW of load, with a third of the addition being electric vehicle load, and the remaining being additional air conditioning load.

In the **Green Ambition** and **Focus on Efficiency** scenarios, there is assumed to be no growth in air conditioning demand relative to 2015/16, assuming that cooling needs are addressed in other ways e.g. building design. So these incremental scenarios reflect the difference between low and high scenarios for electric vehicles only.

## 8.7 The 'Real Options' Cost Benefit Analysis Model (RO-CBA)

The peak scenarios developed in this project may be used to judge when it is cost-efficient to use a traditional or smart solution to deliver network capacity. A prototype 'Real Options' Cost Benefit Analysis model has been developed to support decisions on whether to provide network capacity in a particular location by traditional reinforcement (asset-based capacity) and/or by purchasing post-fault demand side response from existing demand customers. The prototype model has already been used to support a real business decision to purchase this type of demand side response.

Relative to traditional reinforcement, deployment of Demand Side Response (DSR) typically has a shorter lead-time, greater flexibility in the amount of capacity purchased, and costs are ongoing rather than up-front. A decision support model is required because these two strategic options provide different amounts of capacity and with different cost and risk profiles, and the cost-efficient decision depends on a view of uncertain future demand.

Real Options (RO) thinking is relevant for irreversible expenditure decisions (such as network investment which cannot be easily reversed and the value recouped), which are based on some material uncertainty (such as demand uncertainty) and where there is some flexibility in the response (such as when and how to invest).

Real Options thinking can favour a more flexible approach, by highlighting the benefits from flexibility that other techniques such as those based on discounted cash flow cannot. The result is that RO analysis allows a fair comparison between flexible and inflexible network investment.

Based on work with academics at the University of Manchester, a 'real options' approach was developed to inform cost-effective decisions on how much network capacity to deliver and when, given uncertainty in future peak demand. The chosen approach was tailored to DNO data and processes related to investment decisions for thermal capacity in the Grid and primary part of the distribution network, with the initial academic model in Excel further developed for application by Electricity North West.

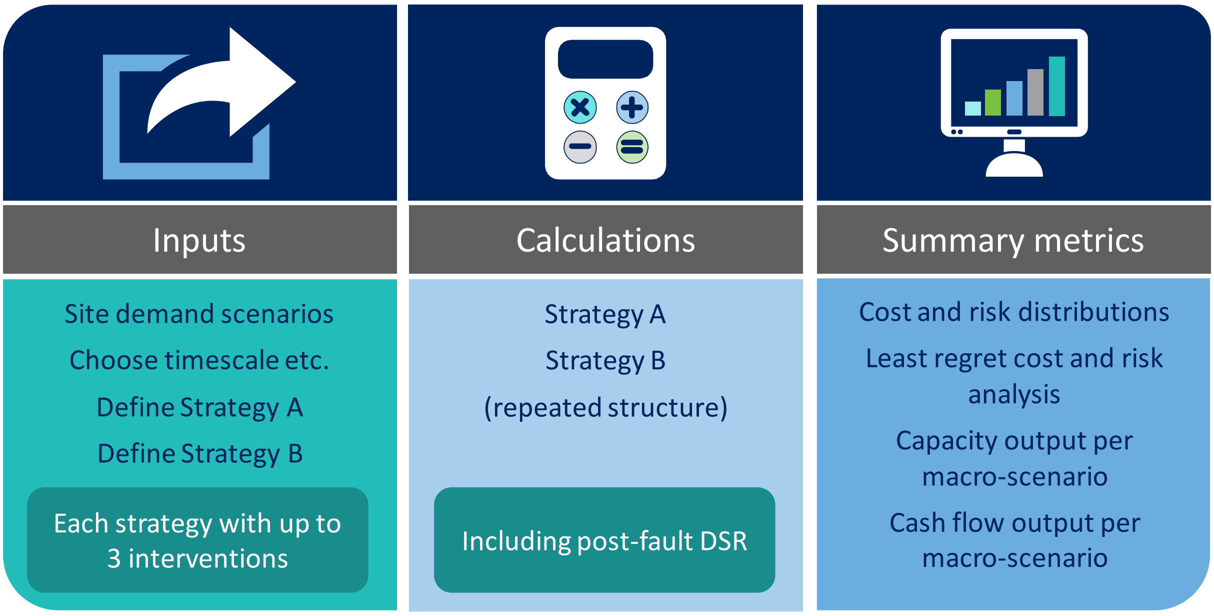
Appendix 4 presents the initial report from the University of Manchester on *'Flexible investment strategies in distribution networks with DSR: Real Options modelling and tool architecture'*. The report provides a comprehensive overview of Real Options (RO) analysis and risk assessment, with focus on potential applications to flexible network investment under uncertainty with Demand Side Response (DSR), and to propose a relevant RO model that could be readily implemented in a spreadsheet tool. This report was produced under the forerunner IFI project, but the development of the model for application as a prototype has occurred under this NIA project.

### The prototype developed

The RO-CBA spreadsheet tool provides various cost and risk metrics to support decisions on what is the most cost-effective intervention to provide thermal capacity on the Grid and primary network. The model does not prescribe how the results should be interpreted, leaving the decision-maker able to interpret whether to focus for example on the best-view scenario, a weighted average approach across scenarios, or a 'least regret' approach which would minimise a cost or network risk.

Figure 13 provides an overview of the model structure. Two strategies are defined for comparison, each with a series of **up to** three interventions with trigger points e.g. commit to delivering an intervention when forecast peak demand reaches a chosen proportion of capacity, at an intervention lead-time of X years ahead. For a planned intervention, the trigger could be set at a chosen year. Three interventions could capture DSR followed by a small reinforcement versus a large reinforcement (but only triggering these if demand levels justified the intervention according to the specified rule). If the user wishes to consider an alternative order of interventions, this would be assessed as a new strategy.

*Figure 13: Overview of the structure RO-CBA model*




Appendix 5 describes the structure of the model and a high-level overview of the model is provided in the presentation available here http://icms.org.uk/downloads/EnergyMan/Shaw.pptx .

The tool can assess interventions against up to 5 'macro' demand scenarios; each macro-scenario is subject to 100 Monte Carlo variations, each reflecting cumulative random variations typical of local factors, and non-cumulative random variations reflecting weather-related variations in demand around an ACS peak value.

For the site, the user provides the demand scenarios with their start year, initial capacity (e.g. firm capacity as established under the P2/6 Engineering Recommendation), peak losses in MW and a loss load factor, and specifies a series of interventions and their trigger points.

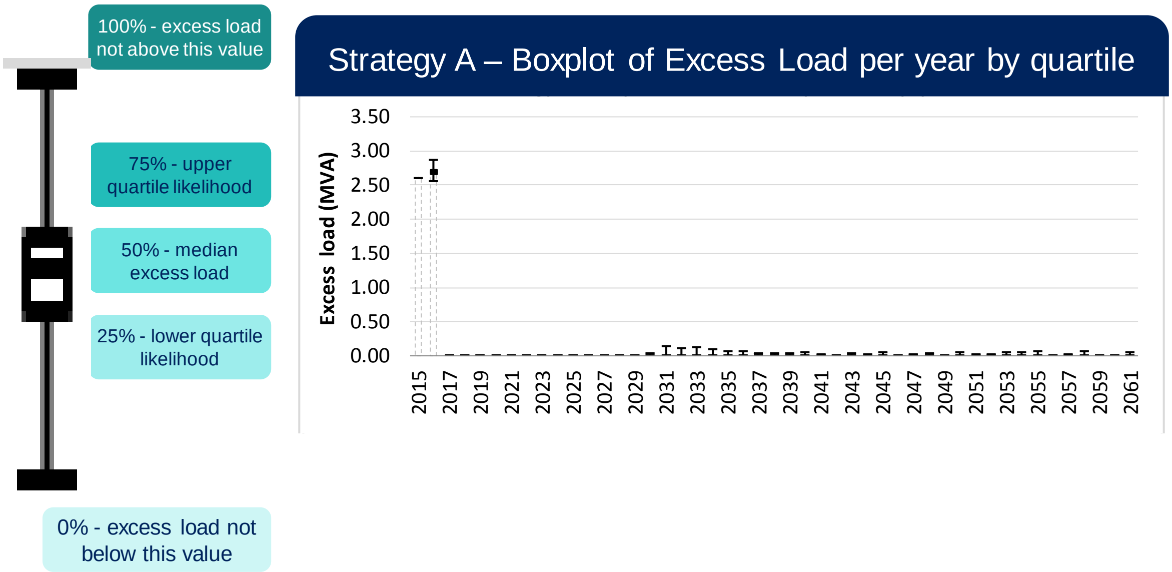
For a traditional asset-based intervention, the user must provide the cost of the intervention, capacity added and peak losses after the intervention. For a post-fault DSR intervention, the user must provide the upper limit on the contribution to peak demand from customers in the target group (currently non-domestics above 300kW in size), typical customer contribution size in kVA, amount of DSR purchased per kVA of required capacity, contract period and lead time.

**Current approach to use of the model**

Based on learning from the Capacity to Customers trial, the model is pre-loaded with default costs for the purchase of that form of post-fault DSR, plus associated contract management costs and network/ customer automation costs. The model would thus indicate if DSR would be financially attractive at typical costs and assuming that customers would contract. This information would then indicate whether the DNO should engage with customers to indicate actual availability and costs of purchasing post-fault DSR. Based on this engagement, the model inputs can then be updated to confirm whether DSR would be financially positive across the demand scenarios.

The current approach is to use the network risk metrics as an initial hurdle, then review the cost metrics. The network risk metrics represent the likelihood of load exceeding capacity over time. Figure 14 shows an example of the boxplots developed to represent this risk, and an example of the output for an intervention which resolves an existing capacity issue, but for which there is a small risk of excess load (<25%) from 2030 onwards. This hurdle approach ensures that both strategies are acceptable in terms of network risk before the financial comparison is made; if one strategy is not judged to have an acceptable network risk, either the details of one of the strategies would need to be altered to proceed e.g. amount of DSR purchased, or this would suggest one strategy is unacceptable and further financial comparison of the strategies would be irrelevant.

*Figure 14: Example of network risk metric over time*




When assessing the financial impact of the scenarios, the user is free to choose which financial approach to use to represent the costs of the interventions as their Net Present Value (NPV). However the model is pre-loaded with the following three views.

1. **Long-term customer impact under the DNO regulatory framework** – reflecting customer impact over 45 years based on Ofgem's CBA framework for RIIO-ED1 (Template 4 issued January 2014).
2. **Short-term cash effect on DNO in RIIO-ED1** – 0% discount rate to 2023, no other effects considered.
3. **Medium-term financial effect on a DNO** (subject to further analysis, not validated in this project) using a DNO-specific discount rate e.g. 4.2% 'weighted average cost of capital' for RIIO-ED1, to 2031, costs scaled back under the DNOs' (Information Quality Incentive e.g. 58% for Electricity North West in RIIO-ED1.

The analysis of the long-term customer impact is the key output of the model, since it may be used to justify whether an approach is financially-beneficial for customers. This approach using a social discount rate of 3.5%, is evaluated over 45 years. It includes the costs of losses to customers (generation and carbon costs) and the costs to customers of financing the DNO's Regulatory Asset Base at an defined capitalisation rate, depreciation lifetime and 'weighted average cost of capital', which combine to effectively raises costs of intervention by 8.36% on an NPV basis.

The financial approach in this view of the RO-CBA model is almost entirely consistent with Ofgem's RIIO ED1 CBA approach, but with slight differences[6] in the long-term beyond 2046. This allowed practical implementation in the model with a single rather than variable discount rate. Although further work beyond the project will quantify this difference in financial approach, it is not expected to be material.

The assumption for demand beyond the timescale on the peak scenarios (2031) is likely to be more material to future cost impacts e.g. continuing a trend or demand remaining flat from 2031 onwards. As shown in Figures 15a and 15b, the cost outputs can be presented both per scenario (ignoring the Monte Carlo analysis) and as a probability distribution (reflecting the Monte Carlo analysis).

[6] The Ofgem RIIO-ED1 CBA template (Template v4 issued January 2014) differs by having a lower discount rate from 2046 onwards (3.5% rather than 3%), ignoring the impacts on the regulatory asset value after 2067 from costs incurred before 2067, and including losses impacts to 2067 rather than 2062. Given all of these future costs impacts beyond 2046 would be heavily discounted, and loading levels are highly uncertain beyond, these differences are not expected to be material.

*Figure 15a: Example NPV cost outputs by scenario*

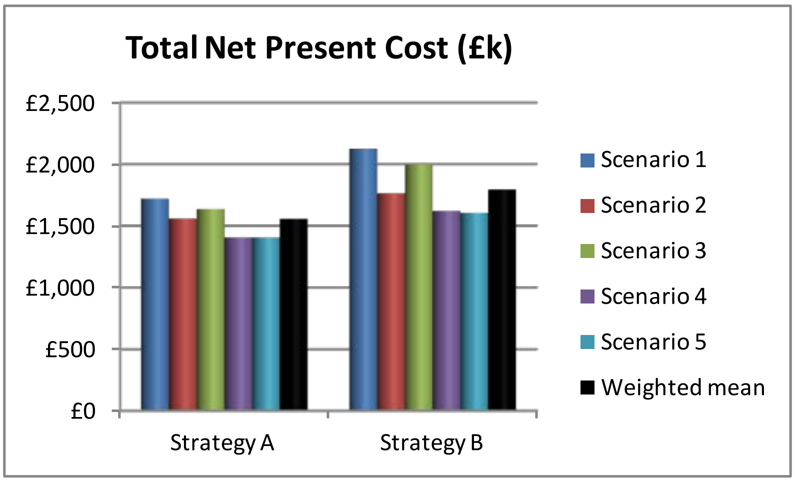
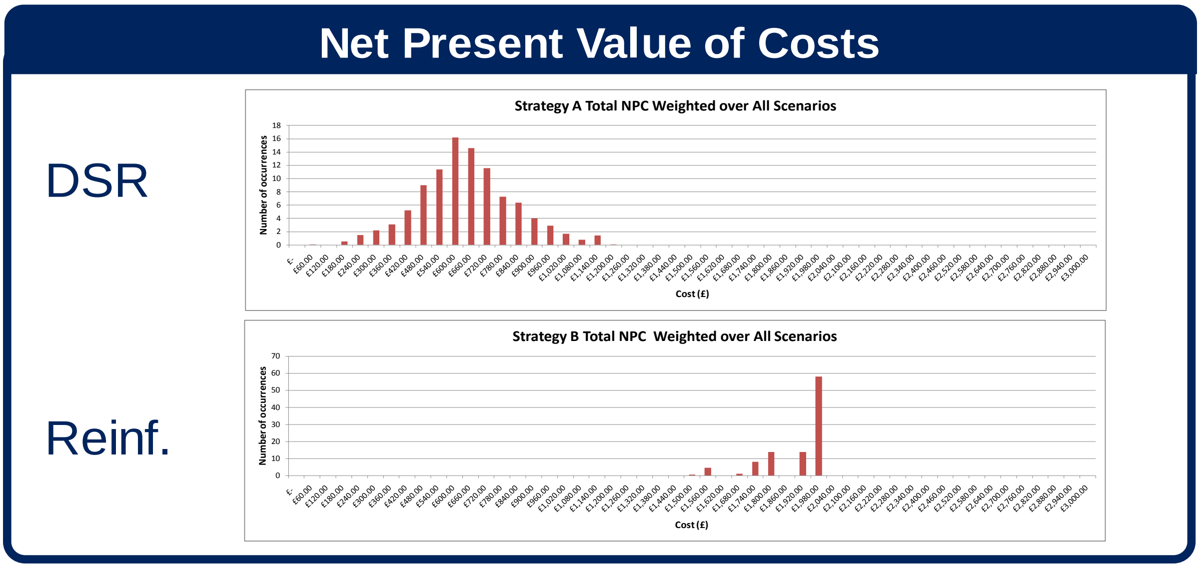



*Figure 15b: Example NPV cost outputs as a probability distribution (x-axis is discounted cost)*




The key difference between the Regulatory Customer view of the RO-CBA and Ofgem's CBA is the ability of the RO-CBA to represent interventions delivered flexibility over multiple demand scenarios (rather than assuming future demand is certain and known), and to calculate an estimate of the costs of delivering post-fault DSR or traditional interventions in each scenario.

As described in section 12, a journal publication and invited presentation have shown that the development of a real options approach to engineering investment is academically significant.

**Business application**

The prototype model is a 34Mb spreadsheet, saved as an Excel binary file. The model is usable in its current form, but further testing, user guidance and optimisation of size and performance will occur as the model is increasingly deployed. As part of this, Electricity North West expects to develop further internal guidance on how to interpret the model results as an input to decision-making on investment in capacity, based on attitude to risk.

The model was used to support a decision in 2016 to proceed with post-fault demand-side-response as the cost-effective alternative to a £5m traditional reinforcement of a primary substation. This enables transition to business as usual of an additional part of an approach developed in the 'Capacity to Customers' LCNF trial. Due to commercial confidentiality, the details of that case are not presented here – but Electricity North West is prepared to make the CBA available to Ofgem as part of justification of the cost-effectiveness of the decision to proceed with an innovative DSR solution.

Appendix 6 outlines how the model was used in the business as part of reviewing and approving whether to use demand response as an alternative to traditional investment. This decision process is currently under review as part of the restructure of related teams. In 2017, the prototype RO-CBA model will be further applied and developed by Electricity North West's Capacity Strategy section to guide decisions about what combination of traditional and DSR solutions will deliver capacity most cost-effectively on the Grid and primary network, identifying the comparative benefits of deploying innovative solutions.

### 8.8 Load scenarios for the secondary networks

Consistent with the inputs to the winter peak scenarios developed for the Grid and primary network in 2015 and 2016, scenarios of winter peak loading were also developed for the secondary networks (HV feeder legs, distribution substations). This was done by setting up new runs of Electricity North West's proprietary Future Capacity Headroom model (FCH). For description of the initial development of the FCH system up to 2014, see the close down report of the First Tier LCNF project 'LV Network Solutions' at www.enwl.co.uk/lvns.

The FCH was updated for new data in this project, rather than significantly altered. Thus the heat pump uptake and profile inputs from the work by Delta-ee (see section 8.4) were aggregated into ASHP and hybrid HP, rather than the six heat pump types being considered separately.

The output of the Future Capacity Headroom (FCH) model is an indication of the approximate number of each type of secondary network asset which would exceed thermal capacity in future years, if no other changes are made to the network. The results of the model can be used as a first step to understand to understand the scale and uncertainty in future volumes of interventions on the secondary network – recognising that interventions could actually be via a mix of asset replacement based on asset conditions, connections-related reinforcement and general load-related reinforcement.

The estimation of the recent history of half-hourly loading of the secondary network was done via Electricity North West's Load Allocation system, which combines HV feeder metering with network connectivity, customer counts and various types of metering data. Load Allocation was initially developed under IFI and LCNF, and is now deployed as business-as-usual to inform automatic restoration of the network and reduce the number and length of interruptions to supply

In this project, a portion of the Load Allocation results were used instead as the estimate of peak loading in 2015/16. For the secondary network fed by each primary, Load Allocation results were extracted for the day of that primary's system-normal winter peak. Future scenarios were then developed for 2022/23, 2030/31 and 2050/51, based on the scenario assumptions developed for the Grid and primary work, so covering differences in domestic v. non-domestic demand per local authority area, and differences in electric vehicle and heat pump uptake per local authority. The baseline Load Allocation results have not been corrected for weather effects; applying the National Grid ACS correction ratio was considered to be unsuitable since ACS reflects the national mix of domestic and non-domestic load, whereas secondary networks assets supply much smaller customer numbers which may not necessarily reflect that national distribution.

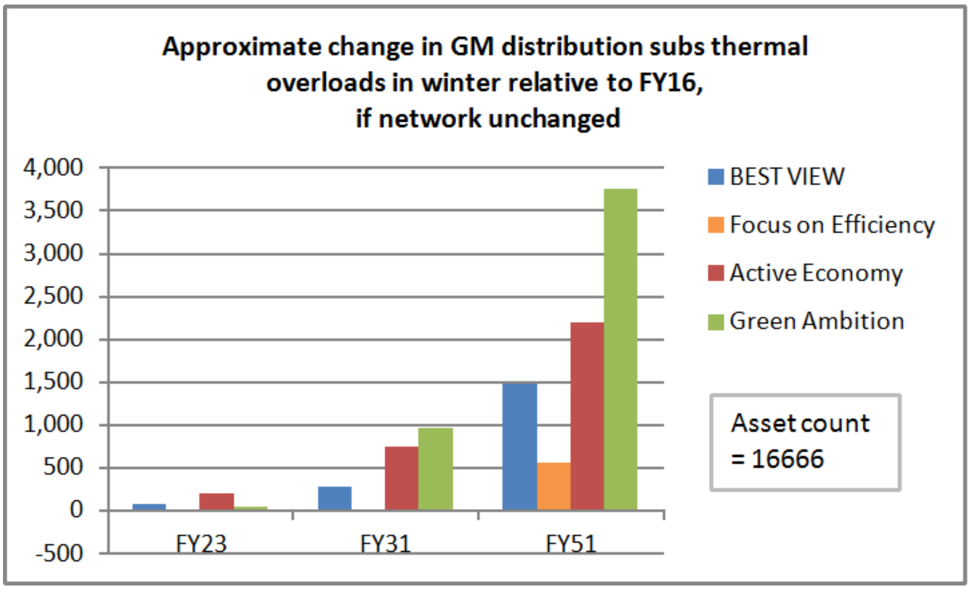
The degree and location of clustering of these new low carbon technologies remains a major uncertainty in all modelling work, so the results should be interpreted as indicative of approximate volumes rather than of the precise location of future overloads. Limitations in the quality of data records and customer allocation to specific assets on the low voltage networks also mean that caution should be used in interpreting the detailed results. However outside of this NIA project, a major data cleanse project is addressing data issues ahead of implementation of a new Network Management System, so the baseline results of the model are likely to become increasingly reliable over the coming year.

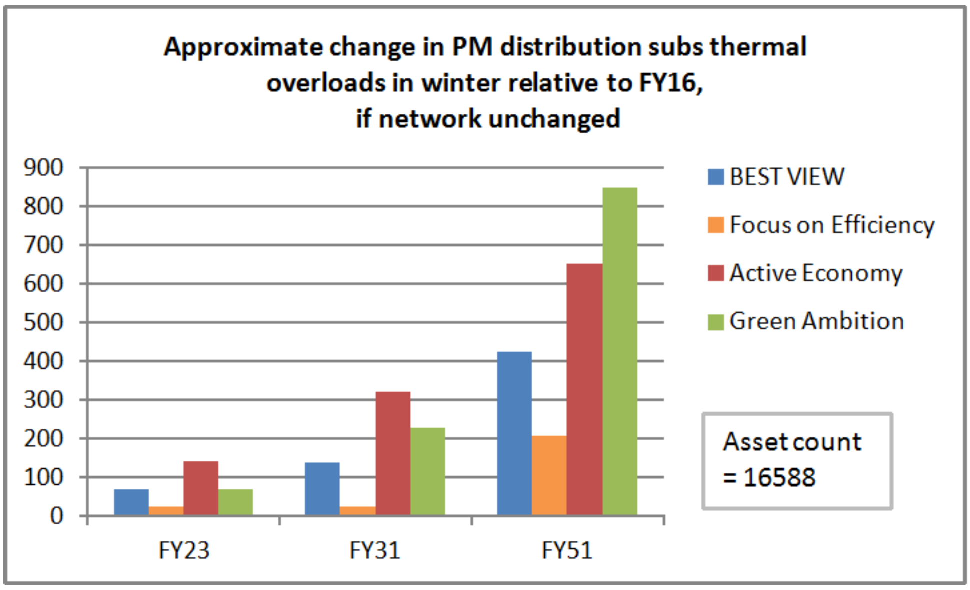
Based on a simplistic view of assuming a thermal overload of distribution substations (ground and pole mounted - GMT and PMT) with observed demand reaching 100% of nameplate rating, and HV feeders reaching 67% of rating by FY23, FY31 and FY51, Figure 16 shows the additional volumes of overloaded secondary network assets relative to FY16. Consistent with Grid and primary, this shows very limited needs for additional interventions to resolve thermal overloads on the secondary networks in the RIIO-ED1 period to FY23, whatever the scenario. However by FY31, the Active Economy and Green Ambition scenarios would require of the order of 1500 interventions on HV feeders and distribution substations, roughly double the scale in the Best View.

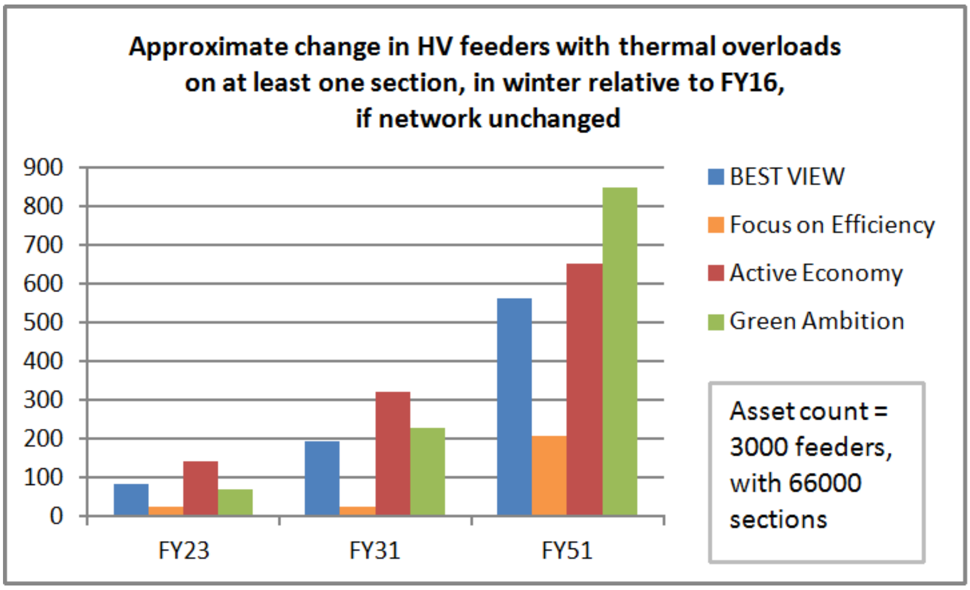
In contrast to Transform (see section 8.4b), the FCH model reflects the network's actual asset population, ratings, network connectivity, customer allocation and estimated loading. The quality of the output is thus a reflection of the quality of the underlying data relating to the secondary networks. In the last eighteen months, Electricity North West has invested significantly (outside of this NIA project) in data cleanse and validation activities in order to improve secondary networks data (especially connectivity on the LV network) as part of the introduction of a new Network Management System.

Some of the predicted overloads in the FCH's base year outputs are clearly spurious if they are a multiple of the rating, and identifying these has been used to guide some aspects of the data cleanse activity e.g. checking ratings, connectivity or the allocation of large customers to assets. The Load Allocation and FCH outputs now benefit from these improvements in the underlying load model, but the outputs of these models are still at the stage where an overload identified by the model on a specific asset would be a trigger for investigation rather than a direct trigger for intervention on the network.

*Figure 16: Historic aggregate peak including effect of applying National Grid ACS factor*






# 9 REQUIRED MODIFICATIONS TO THE PLANNED APPROACH DURING THE COURSE OF THE PROJECT

## 9.1 Summary for Smarter Networks Portal

Several modifications were made to the planned approach, in order to deliver the project objectives most cost-effectively. These changes reflected the interaction with the ATLAS NIA project, which was launched during the course of the Demand Scenarios NIA project.

1. As described in sections 8.4b and 8.8 of the full version of this report, Transform® was used rather than the FCH to deliver the detailed analysis of heat pump impacts on the secondary networks, as Transform could be more cost-effectively adapted within the project timescale to accept inputs relating to multiple domestic HP types, and to estimate the costs of secondary network reinforcement for thermal and voltage constraints. Transform provided outputs using a generic distribution network – which was appropriate for the policy questions in this project – but unlike FCH does not reflect the detail of network connectivity, capacity and loading on the real Electricity North West network.

   The specification of additional FCH development will be informed by the work in this project, but has been transferred into the ATLAS project in 2017, allowing the successor to the FCH to benefit from changes to systems for secondary networks loading data associated with the introduction of a new Network Management System.

2. The scope was extended from just winter peak scenarios to both winter and summer peak scenarios. This was facilitated by application of the initial version of the data processing methodology from ATLAS, which enabled systematic identification of both winter and summer peaks with no additional manual effort.

   There were three reasons for the extension. Firstly, summer peaks appeared to have been increasing more rapidly than winter peaks, particularly in central Manchester, but summer peaks had not been systematically reviewed. Secondly, given that summer equipment ratings are lower than winter, this could increasingly be leading to summer becoming the season of most onerous demand relative to rating. Thirdly, engagement with the academic research in the RESNET project indicated the long-term importance of growth in summer peaks, even relative to winter peaks.

   As a result additional consultancy work was commissioned from the Tyndall centre on the past and future contribution of air conditioning to summer peak load (see section 8.6).

3. Extension of the heat pump analysis from Delta-ee to provide enhanced results to support ATLAS. Reflecting on the feedback received during the dissemination of the heat pump profiles (see section 12) and the year-round half-hourly requirements of the ATLAS project, at the end of 2016 a short piece of additional work was commissioned from Delta-ee. This adapted the peak profiles for a mix of single and two heating periods, added half-hourly profiles for the *average behaviour per month*, and extended the analysis to include a domestic ground source heat pump (GSHP) profile.

   GSHPs were not considered in the original analysis, since their uptake numbers are a relatively small proportion of total uptake by 2030. However GSHP is an appreciable proportion of uptake in the next 10 years, so this extension work was commissioned to improve the credibility of ATLAS' scenarios in the next few years.

4. Identifying the contribution of non-monitored generation such as domestic PV to meeting true demand had been originally envisaged as part of this project. However it was recognised that it was more meaningful to develop both this and an improved approach to weather-correction as a full half-hourly year-round analysis, rather than focused on times of peaks. Thus both these activities are now being developed in the ATLAS NIA project.

5. Given that the Demand Scenarios project now represents an intermediate step in the development of the ATLAS load forecasting approach, it was decided that it would be inefficient to rewrite the company's detailed Code of Practice on demand forecasting at this stage as an output of the Demand Scenarios project. Instead that superseded Code of Practice document is being withdrawn and replaced by a high-level Electricity Policy Document, reflecting the approach described in this closedown report.

The original project budget was £500k. Reflecting these changes, the final project expenditure was £318k as shown in the table below (rounded, subject to final accounting validation).

### 9.2 Cost Variance Table

*This section does not appear on the Smarter Networks portal.*

| Item | Category | Estimated Costs £k | Final Costs £k rounded | Variance |
|---|---|---|---|---|
| 1 | Project Management and dissemination | 30 | 20 | -10 |
| 2 | External modelling inputs – heat pump and air conditioning | 170 | 203 | +33 |
| 3 | Historic loading corrections, development and delivery of load scenarios and prototype RO-CBA model | 300 | 95 | -205 |
| | **Total** | **500** | **318** | **-182** |

## 10 LESSONS LEARNT FOR FUTURE PROJECTS

Lessons learnt can be divided into five areas; the first three of these areas are addressed in further detail in the next section on 'Planned implementation'.

1. Peak load scenarios can be delivered which reflect local differences per substation, related to differences in domestic and non-domestic behaviour, and difference per local

authority area. New inputs allowed heat pump and air conditioning impacts to be characterised. This learning feeds into ATLAS.

2. It is a misleading simplification to focus on a single half-hour of winter/summer peak demand based on active power demand when the profiles of underlying demand, LCTs and DG are so much more complex. It is also a misleading simplification to assume the future relationship between MW and MVA is constant at its value in the base year. Future approaches to demand forecasting/ scenarios need to reflect this. This learning feeds into ATLAS.
3. Real options approaches can be developed to support decisions about interventions on the network which materially depend on uncertain demand. Electricity North West is now preparing to deploy this as business-as-usual.
4. Characterising the future impact of air conditioning is challenging. Although ATLAS will improve the time-resolution of these scenarios, further research is required to characterise air-conditioning to develop adequate scenarios on which to base planning decisions and to seek mitigating actions either with customers or on the network.
5. The impact of domestic heat pumps is highly variable, and will depend on both external temperature and the type of heat pump and dwelling. That sub-project made the following recommendations:
    a. Planning policy should consider planning the network for a ‘one in 20’ winter peak rather than an ‘average’ winter peak ie 5.5 kW additional load per heat pump rather 2.2 kW. Implications will be different for non-diverse ASHP loads on the secondary networks, versus the mix of ASHP and hybrid HP in diversified aggregate loads at primary substation and above.
    b. Explore further the impact that clustering of heat pump uptake could have on the LV network – combinations of different heat pump types and networks lead to variable impacts.
    c. Develop projects/trials to explore the cost effectiveness of ‘customer side measures’ that could be implemented to manage and reduce the impact of heat pump uptake on the LV network, such as increased insulation, oversized heat pumps and incentivising hybrids.
    d. Continue to engage with other energy stakeholders (eg National Grid and supply companies) to understand their challenges and priorities at the system level, and how this may influence the operation of heat pumps and impacts on the distribution network. The analysis in this report shows that ‘optimising’ heat pump operation (to increase the use of lower cost electricity generation) will likely increase the overall impact of heat pumps.

# 11 PLANNED IMPLEMENTATION

### Peak Load Scenarios

The revised approach to peak loading scenarios which has been developed in this project was used in 2016 to produce Electricity North West’s *best-view* peak loading scenario for GSP, BSP and primary substations. These fed into delivery of reports to National Grid (‘Week 24’), Ofgem (Reinforcement Load Index section of the ‘RRP’) and wider stakeholders (‘Long Term Development Statement’).

Those reporting requirements do not *at present* require other scenarios to be presented, but this is a likely future development for which this project is preparation.

The Future Capacity Headroom model was also used to develop loading scenarios for the secondary networks, which inform business planning and asset management plans but do not currently feed into company reporting.

### Future approaches to Demand Forecasting in the ATLAS project

The learning on *peak* loading scenarios is now being transferred into the ATLAS project (www.enwl.co.uk/atlas) which runs from November 2015 to December 2017. ATLAS extends the Demand Scenarios project taking a year-round half-hourly approach to active (P) and reactive (Q) power demand.

ATLAS' P scenarios use Demand Scenarios' structure for underlying plus incremental demand, and continue to use inputs per local authority for changes in customer numbers and in economic activity. The split of domestic versus non-domestic demand in the Demand Scenarios project is continued but further disaggregated in ATLAS. The incremental component in ATLAS uses the domestic heat pump inputs and air conditioning inputs developed in the Demand Scenarios project.

Corrections from measured to 'true' demand highlighted issues with the completeness, accuracy and connectivity-naming conventions of data on generation connected. Learning from in this area is being applied and further developed in ATLAS. Similarly the experience around consistently defining substation names and connectivity is also being transferred to ATLAS.

Learning from the application of the Future Capacity Headroom model will also be used to inform the next part of the ATLAS project, which will produce a functional specification for a new load scenario / capacity tool for the secondary networks by the end 2017. This new model will use the improved estimates of secondary network loading which will be delivered by Electricity North West's new Network Management System by early 2019.

In Electricity North West's Losses Discretionary Reward submission to Ofgem in 2016, a plan was described to further extend the analysis of secondary networks loading being developing in Demand Scenarios and ATLAS, and combine it with a new CBA tool. This will use insights from the RO-CBA tool, in order to identify and prioritise interventions to reduce losses on the secondary networks.

**Identifying the most efficient strategy for investment in capacity**

The set of primary peak loading scenarios and the prototype RO-CBA model have been used together in 2016 to support a BAU decision to sign a contract to purchase post-fault demand-side-response from one customer, avoiding a traditional investment of several million pounds to add a second transformer at a primary substation. The details of this project are commercially confidential, but will be reported to Ofgem. The RO-CBA model was used to demonstrate that the smart investment would be:

- a cost-efficient investment to customers in the long-term under Ofgem's RIIO-ED1 CBA framework, taking into account realistic demand scenarios,
- commercially positive for Electricity North West, and
- an acceptably low risk of load exceeding capacity.

# 12 FACILITATE REPLICATION

*This section appears in the 'Other Comments' section on the Smarter Networks portal.*

This section describes activities to disseminate the results of the project externally, to allow others to use and replicate the learning. Other network operators and interested parties can use the reports and data to inform their own planning and decision processes.

The project has a dedicated web page, and the report, appendices and supplementary data such as presentations are being made available for download via the Electricity North West website at www.enwl.co.uk/demandscenarios .

A presentation at the Electricity North West stand at the Low Carbon Networks and Innovation conference in Manchester in October 2016 described the Demand Scenarios project and its input to the ATLAS project. The presentation is available at http://www.enwl.co.uk/about-us/the-future/home/lcni-conference-2016.

An overview of the two projects was also produced to support dissemination at LCNI and is available at http://www.enwl.co.uk/docs/default-source/future---demand-scenarios/atlas-factsheet.pdf?sfvrsn=4 .

**Demand Scenarios including Heat Pump and Air Conditioning analysis**

The report on the heat pump analysis is provided in Appendices 1 and 2, with the detailed half-hourly profiles for each 'heat pump - house type' on our website.

Early results of the project were presented in March 2016 to the ENA's Low Carbon Technologies working group. Once completed, a webinar describing the results of the heat pump analysis project was held on 14th July 2016. The 80 participants registered from 60 organisations and 42 joined the webinar. A recording of the webinar is available online at: https://www.youtube.com/watch?v=Pub8Fmz9yPg). The findings on heat pump flexibility in section 8.4c are being shared with BEIS/Ofgem as part of their 2016 Call for Evidence on 'A Smart Flexible Energy System'.

The detailed heat pump profile results were provided in April 2016 to EA Technology for consideration in the update to the heat pump profiles in the generic 'Transform' model of Great Britain's electricity networks. The 2016 update of Transform (version 5.2) directly uses the hybrid profiles from this project, and for ASHP uses a combination of these profiles and those from the Low Carbon London project.

Prior to delivery of the air conditioning work package, the issues of summer heat demand - for the electricity sector and more widely - were highlighted in an event and short film organised as part of the University of Manchester's 'Policy Week' 2015.
http://macf.ontheplatform.org.uk/event/hot-city-urban-resilience-and-cooling

http://www.mace.manchester.ac.uk/our-research/centres-institutes/tyndall-manchester/news-events/newsarchive/new-film-hot-in-the-city-explores-how-the-urban-heat-island-may-affect-manchester-and-its-electricity-network-.htm

The overall peak scenarios, the heat pump results and the air conditioning analysis have all been shared via bilateral meetings with National Grid's Future Energy Scenarios team, informing their scenarios for 2016 and 2017. In particular, National Grid attended the review meeting for the air conditioning work with the University of Manchester.

**The Real Options Approach**

During 2016, in bilateral meetings with Ofgem, Electricity North West has highlighted the use of our prototype model to support decisions about when it is efficient to progress traditional reinforcements as an alternative or in combination with a smart technique such as post-fault demand response.

The approach in the Real Options model was described at an invited presentation to a workshop on 'Energy Management: Flexibility, Risk and Optimisation' at the International Centre for the Mathematical Sciences in Edinburgh on 10th June 2016. The presentation can be found at http://icms.org.uk/downloads/EnergyMan/Shaw.pptx .

Outside of the NIA project, work by the University of Manchester academics on developing and applying their own version of the real options model led to a peer-reviewed open-access publication in the Energy Policy Journal. This paper is publicly available and may be referenced as follows.

Schachter J.A., Mancarella P., Moriarty J., and Shaw R. (2016) "Flexible investment under uncertainty in smart distribution networks with demand side response: Assessment framework and practical implementation", **Energy Policy**, Vol. 97, Oct 2016, pp 439–449. http://dx.doi.org/10.1016/j.enpol.2016.07.038

Also outside the NIA project as an extension to the problem simulated in the RO-CBA for post-fault DSR, Prof. John Moriarty has been working on 'stochastic optimisation techniques'. This is a way to identify the optimal set and order of DSR purchases. While the number of

DSR purchases per site is small (up to 3) and all feasible options can be evaluated, this is not a necessary extension of the RO-CBA model. However this points towards further development of the techniques in the RO-CBA.

The RO-CBA model as developed is tailored to supporting decisions about providing thermal capacity for demand at Grid and primary sites, either by traditional or post-fault DSR. Further development work is envisaged to allow the principles of the RO-CBA to be applied to other investment decisions where there is material demand uncertainty e.g. different voltage levels, different innovative solutions, resolving fault-level rather than thermal issues.

# 13 APPENDICES

| | |
|---|---|
| **Appendix 1** | **Delta-ee overview**<br>***Heat pump house type characterisation*** |
| **Appendix 2** | **Delta-ee report**<br>***Managing the future network impact of electrification of heat*** |
| **Appendix 3** | **Tyndall Centre at the University of Manchester**<br>***Air conditioning demand assessment*** |
| **Appendix 4** | **University of Manchester**<br>***Flexible investment strategies in distribution networks with DSR:***<br>***Real Options modelling and tool architecture*** |
| **Appendix 5** | **Electricity North West Ltd.**<br>***Prototype Real Options Model: Tool Description*** |
| **Appendix 6** | **Electricity North West Ltd.**<br>***Demand Response Review and Approval Process*** |