NIA ENWL008
Architecture of Tools for Load Scenarios (ATLAS)

Closedown Report

31 July 2018

VERSION HISTORY

Version	Date	Author	Status	Comments
V0.1	9 February 2018	Rita Shaw Model Development Lead	Draft	Structure and early draft
V1.0	31 March 2018	Christos Kaloudas Forecasting Manager	Final	First complete draft

REVIEW

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APPROVAL

Name	Role	Date
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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) NIA project
BSP	Bulk supply point – mainly 33kV/132kV for the Electricity North West network
Capacity to Customers (C_2C)	Electricity North West's Second Tier LCN Fund project (delivered between 2012 and 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
CLAVA	Meter data validation and losses reporting system (www.st-clements.co.uk/)
DECC	Former Department of Energy and Climate Change, and the 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
Demand Scenarios	Demand Scenarios with Electric Heat and Commercial Capacity Options (NIA project)
DG	Distributed generation ie generation connected to a distribution network
DNO	Distribution network operator
DSR/DSM	Demand side response/demand side management
DUKES	Digest of UK Energy Statistics
EELG	Element energy load growth model (for the EHV network)
EHV	Extra high voltage network that extends from the interface with transmission down to primary substations
ENTSO-E	European network of transmission system operators for electricity
ENWL	Electricity North West Limited – the DNO for the North West of England
ESO	Electricity system operator
EV	Electric vehicle
FCH	Future capacity headroom model (for the secondary networks)
FLH	Fault level headroom
FY	Financial year eg 2014/15 is FY15
GDP	Gross domestic product
GMT	Ground-mounted transformer
G&P	Grid & primary network, ie the EHV network or substations including GSP, BSP and primaries

Term	Description
GSP	Grid supply point – connection from DNO network to National Grid's transmission network
GVA	Gross value added
(Hybrid) HP	Heat pump – a hybrid combines an electric heat pump with gas boiler
HV	High voltage, eg 6.6kV or 11kV
LCN Fund	Low Carbon Networks Fund
LCT	Low carbon technologies such as electric vehicles (EV) and electric heat pumps (HP)
LF	Load factor – the ratio of average demand in a specified period to the peak demand in the same period
LTDS	Long-term development statement
LV	Low voltage, eg 230V phase or 400V polar voltage
MATLAB	Multi-paradigm numerical computing environment and proprietary programming language developed by MathWorks
MW, MVA, MVAr	Mega Watt, Mega Volt Amperes, Mega Volt Amperes Reactive – in this project, averaged over half-hourly periods
NIA	Network Innovation Allowance
NPV	Net present value
OBR	Office for Budget Responsibility
OLTC	On-load tap changer of power transformer
pf	Power factor
PMT	Pole-mounted transformer
Primary	Primary substation – 33/11 or 6.6kV for the Electricity North West network
RIIO-ED1	Revenue = Innovation Incentives Outputs – Electricity Distribution 1, the current regulatory period for DNOs – 1 April 2015-31 March 2023
RIIO-ED2	Revenue = Innovation Incentives Outputs – Electricity Distribution 2, the next regulatory period for DNOs – 1 April 2023 onwards (date tbc)
RO-CBA	Real options approach to cost benefit analysis
Secondary Network	Network downstream of secondary substations – typically 11 or 6.6/0.4kV for the Electricity North West network
T-D	Transmission to distribution
Transform Model®	Generic model of the electricity networks, developed by EA Technology for Workstream 3 of the Smart Grid Forum
TSNM	Time-series network modelling
TSO	Transmission system operator

1 EXECUTIVE SUMMARY

This document corresponds to the closedown report of the Architecture of Tools for Load Scenarios (ATLAS) project at Electricity North West Limited, funded under the Network Innovation Allowance (NIA) scheme.

1.1 Aims

The aim of the ATLAS project was to develop credible methodologies and associated prototype tools for the long-term forecasting of demand (ie MW, MVAr and combined in MVA) and generation across the G&P networks of Electricity North West. Similar to the Future Energy Scenarios (FES) produced and used by National Grid, the proposed approach uses scenarios to model uncertainties around future demand and generation. The ATLAS project was established to achieve the following primary objectives:

- To produce demand and generation forecasting outputs that enable well-justified strategic planning of network capacity and good decisions about solutions to capacity problems
- To provide historical load analysis and forecasting scenarios to demonstrate efficient load-related expenditure in Ofgem's RIIO-ED1 price control and support a well-justified business plan for RIIO-ED2
- To meet annual reporting obligations to the ESO (ie National Grid) and Ofgem more accurately and credibly, as well as enhancing an informed dialogue with the ESO and other stakeholders
- To provide better information to stakeholders and customers on future loading, thus enhancing customers' experience of connections.

1.2 Methodology

The ATLAS project has developed methodologies and associated prototype tools for the long-term demand and generation forecasting of grid & primary (G&P) substations (ie GSP, BSP and primary substations). The methodology is used to define five scenarios and associated per scenario outputs (ie MW, MVAr and combined MVA) of true, latent and measured demand per GSP, BSP and primary substation.

The ATLAS project recognised that network planning decisions should consider not only peak demand forecasts (in MVA), but also scenario forecasts focusing on minimum demand (eg, used for DG connections), profile characteristics (ie, load factor assessments to define network asset ratings) and reactive power flows during periods of peak and minimum demand (ie, to assess the effects on available transformer tap headroom and Q exchange interactions with the TSO).

It also recognised that practical reasons derived from modern challenges in distribution network planning have necessitated the requirement of time-series outputs (ie half-hourly) for demand and generation forecasts. For example, focusing on forecasting P demand, it is the profile characteristics of low carbon technologies (LCTs) that can shift the time that peak demand occurs at a substation. It is also the combination of maximum generation with minimum demand (in MVA) that can define the available thermal capacity for new generation connections. Moreover, when it comes to forecasting maximum VAr exports from distribution to transmission networks (ie, affecting transmission voltages during periods of minimum load), these exports do not coincide with the time of minimum P demand.

ATLAS built on the previous approach followed by Electricity North West to forecast peak demand. It also used the expertise of Element Energy Limited (EE) to utilise domestic and I&C customer data in a bottom-up modelling approach that was previously developed by EE to produce load growth models for Northern Powergrid and UK Power Networks.

The forecasting tools for P demand and generation of the proposed ATLAS methodology:

- Use weather corrections and time series (ie half-hourly) analyses and outputs
- Use the learning from the Demand Scenarios NIA project in the Element Energy Load Growth (EELG) model by considering demographic and economic differences per local authority and the way that domestic heat pumps and air conditioning can affect winter and summer peak loads
- Incorporate economic growth, consumer choice modelling, changing building stock and demographics in the EELG model population; and consider energy efficiency improvements, the profile characteristics of LCTs and new technologies
- Take into account accepted connections of demand and DG (outside EELG model).

ATLAS also produced a methodology and associated tools for the forecasting of Q demand which builds on the REACT project (ie, 2013-2015 collaborative project across all British DNOs and National Grid to investigate future Q exchanges at T-D interfaces) [1] by:

- Starting from the forecasting of Q demand at primary substations by combining identified historical seasonal Q/P ratio trends (individual trends for peak and minimum demand) with P demand forecasts
- Moving to the Q forecasting at GSP and BSP substations using time-series modelling of the whole of the EHV networks and proper network modelling adjustments (further to the ones followed in REACT).

1.3 Outcomes

The prototype tools produced as part of ATLAS project include:

- Data processing and non-monitored DG estimate tools developed in MATLAB software
- Element Energy Load Growth (EELG) model produced by Element Energy in Excel-VBA format (for true and latent P demand forecasting)
- Tool that combines EELG outputs with demand and generation connections data to produce final scenario forecasts of P demand in MATLAB software
- Time-series network modelling tool for Q forecasting using modules developed in IPSA, Python and MATLAB software platforms
- Empirical Q forecasting tool produced in Excel (used to demonstrate that the detailed approach is preferable and to provide National Grid with an enhanced modelling approach).

1.4 Key learning

The developed scenario-based P demand and generation forecasting methodology has significantly enhanced the approach followed previously by Electricity North West by:

- Moving from annual peak demand forecasting to time-series analysis and outputs using half-hourly resolution through year
- Assessing historical true P demand a) using data processing, b) taking into account the effects of non-monitored generation and demand suppressed by on-site generators; and, c) using a new weather correction approach
- Incorporating updated profiles for LCTs and new technologies
- Using increased granularity by going down to postcode sector data analyses.

The implementation of a Q forecasting methodology is novel among DNOs and can be used to help the TSO in managing transmission voltage levels and DNOs in having a better understanding of future Q demand levels at GSPs for the different scenarios and potential effects on EHV voltages and transformer tap headrooms. Key learning from the developed approach is as follows:

- It was demonstrated that the effects from the interactions of future mixes of demand and generation with the EHV network assets can be critical in the overall Q demand at T-D interfaces. This underlines the significance not only of time-series analyses, but the necessity of network modelling that incorporates operational aspects

- It was justified that a detailed time-series network modelling approach instead of an empirical rule for the EHV network effects should be used after ATLAS in business as usual
- The overall Q demand at T-D interfaces can be decomposed as the summation of a) the Q demand monitored at primary substations and large EHV generation, b) the Q absorption across EHV transformers and circuits; and, c) the Q gains across EHV circuits. This process revealed the extent to which that existing and future network, demand and generation changes can affect overall Q demand.

1.5 Conclusions

The ATLAS project has delivered scenario-based methodologies and prototype tools to enhance the P demand forecasting (in MW) and develop a novel Q demand forecasting (in MVAr) approach. The developed prototype tools are currently being transferred into business as usual processes to meet the planning and reporting aims mentioned above, as well as to facilitate a constructive dialogue with the ESO and other stakeholders.

1.6 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. Selected sections of this full closedown report (sections 2-6, 7.1, 8.1, 9 and 11-14) are available via the Energy Networks Association's Smarter Networks learning portal at www.smarternetworks.org. This full version of the report provides additional information that is useful in understanding the project in more detail.

2 PROJECT FUNDAMENTALS

Title	ATLAS – Architecture of Tools for Load Scenarios
Project Reference	NIA_ENWL008
Funding Licensee(s)	Electricity North West Limited
Project Start Date	November 2016
Project Duration	2 years 1 month
Nominated Project Contact(s)	Steve Cox, Engineering and Technical Director innovation@enwl.co.uk

3 PROJECT BACKGROUND

Loading is the basis of the requirement for distribution network capacity. It thus supports all distribution network investment, either directly or indirectly. Trends in network loading are a combination of demand and generation, and are increasingly uncertain under the transition to a lower-carbon economy. In the three years before ATLAS, Electricity North West focused on developing an understanding of winter peak loading on the network, and its future uncertainty. However given the modest short-term outlook for peak demand, future load-related investment requirements are likely to be driven not just by changes in peak demand, but also by changes in minimum load/reverse power flows and in reactive power flows. There is increasing focus from National Grid and Ofgem on reporting and forecasting of these changes.

More onerous compliance requirements for minimum demand at grid supply points (GSPs) are likely in future, based on implementation of the forthcoming European Demand Connection Code, and changes to the Statement of Works process. Our existing load analysis and scenario processes did not address these needs, so there was a requirement to develop automated tools to deliver this wider scope of load analysis, and to do this consistently across all network assets. A better understanding of current and future loading, and how this compares to capacity, could also be used to improve information to connections customers.

The ATLAS project is focused on the technical development of improved methods of load estimation, creation of scenarios, and indicative comparison to network capacity, rather than technical or commercial solutions to any loading constraints identified. The ATLAS project was broken down into the following phases:

Phase 1 – Detailed scoping of requirements, plus identification and appraisal of potential methods for correcting baseline data and generating scenarios; timescales: 3-6 months

Phase 2 – Methodology development, including specification and creation/procurement of any new inputs to the future scenarios, a full prototype of the grid & primary tool (GSP connection groups, GSPs, BSPs, primaries) and partial prototypes of the secondary networks tool; timescales: 15-18 months

Phase 3 – Specification for final tools – grid & primary, secondary networks and any cross-over interface; timescales: 3 months.

4 PROJECT SCOPE

The scope of future analysis needs to expand from the existing focus on peak loading in MVA, based on winter peak MW loading.

The expanded analysis covers winter and summer conditions, both peak loading and minimum or reverse power flow, including the effects of generation. The outputs include indicative comparisons to thermal capacity. Future loading is expressed with uncertainty eg scenarios and volatility measures.

This is delivered in a consistent way across all distribution network assets – GSP, BSP, primary and secondary networks, although the implementation differs. In particular the grid & primary analysis is per substation, corrected for weather and generation effects, and covers the range of active power flows, reactive power flows, apparent power, power factor and load factor over a year (P, Q, MVA, pf, LF).

For the secondary networks, given the lack of historical data on loading and uncertainty in the local geographical spread of new technology, there is a simpler analysis, and future scenarios are interpreted on a volume basis ie suggesting a number of assets exceeding capacity in future.

The project delivers the methodology, prototypes and specifications for an enduring automated business solution to analysing current load, generating future scenarios and providing indicative capacity assessments. The project builds on the analysis and tools developed in elements of the following Electricity North West innovation projects:

- Low Voltage Network Solutions (2011-2014) eg Future Capacity Headroom model of the secondary networks
- Demand Forecasts and Real Options (IFI) – 2013-2015

- Demand Scenarios with Electric Heat and Commercial Capacity Options (NIA) – 2015-2016 – developing peak demand scenarios at grid & primary
- Reactive Power Exchange Application Capability Transfer – REACT (2013-2015) with National Grid and all DNOs.

5 OBJECTIVES

The ATLAS project aims to develop the method to deliver historic estimates and future annual scenarios of asset loading to 2031, and to make indicative comparisons of these to thermal capacity. This will provide inputs to network/business planning, information for stakeholders and help fulfil mandatory reporting requirements.

This project supports four primary objectives:

- To support efficient decisions about load-related investment in the RIIO-ED1 regulatory period (2015-2023)
- To justify the plan for efficient load-related investment in the RIIO-ED2 regulatory period (2023-2031)
- To more efficiently and accurately meet our 'Week 24' reporting obligations to National Grid, and support compliance with future restrictions on the operational envelope of GSPs
- To provide better information to stakeholders and customers, enhancing customer service.

By better understanding current and future loading, this will support the business to provide only necessary network capacity and investments, thus minimising the economic and environmental impact of the networks.

6 SUCCESS CRITERIA

- Automate correction and analysis of peak and minimum load behaviour across all grid & primary substations
- Deliver a prototype tool for annual P and Q load estimates and indicative capacity assessments across all grid & primary substations, including to automate delivery of a wider scope of estimates and scenarios of GSP connection group loadings to National Grid in the 'Week 24' submission, and for future regulatory reporting required by Ofgem
- Amend internal policies accordingly, and specify the business-as-usual approach for grid & primary substations
- Deliver partial prototypes of load estimates and indicative capacity assessments across the secondary network, and specify the future business-as-usual system to be based on the improved load estimates expected to be available from 2018 onwards.

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

The ATLAS project has successfully delivered against its original aims, objectives and success criteria. This section firstly covers how the project has delivered against the success criteria defined, then against the objectives.

In relation to the first success criterion, data processing tools have been created and applied in MATLAB software. These combine half-hourly data from Electricity North West’s systems indicating measured substation loading and generation export to produce half-hourly data sets of:

- true demand (P) and measured demand (P and Q)
- for each GSP, BSP and primary substation and
- corrected for data loss, spikes and switching actions to present demand in normal network operation.

Furthermore, algorithms developed in MATLAB software are used to automate estimation of the output of non-monitored generation per substation (ie implemented half-hourly through last five financial years), in order to give a full view of the historical true demand (P). Element Energy then use the half-hourly true demand history to find the correlation at every substation between true demand, daylight hours and a regional temperature dataset to deliver per-substation correction of true demand against the historical monthly average temperature range.

The outputs are full half-hourly corrections of historical load behaviour, which enables historical seasonal trends of peaks/minima and daily load factors to be automatically identified (subject to visual and other engineering sense checks).

A description of the initial version of the data processing methodology was published at www.enwl.co.uk/atlas in autumn 2016. The tool was then further developed to produce an updated dataset for GSP, BSP and primary true demands in February 2017.

In relation to the second success criterion, methodologies and tools were created to develop spatially-disaggregated P and Q scenarios by substation. In order to use a bottom up approach (ie, down to post sector data) to model domestic, industrial and commercial true and latent demand, the expertise that had been previously developed by Element Energy in the production of load growth models for UK Power Networks and Northern Powergrid in other innovation projects was adapted and extended.

Since May 2016, Element Energy has worked with Electricity North West on ATLAS to produce an Excel-based load growth model which can demonstrate a wide range of scenarios. Scenarios of true demand are linked to characterising demand in a set of 'customer archetypes' linked to external geographic datasets.

The ATLAS form of the Element Energy model uses the learning from the 'Demand Scenarios with Electric Heat and Commercial Capacity Options' NIA project by considering demographic and economic differences per local authority and the way that domestic heat pumps and air conditioning can affect winter and summer peak loads.

It also meets the wider scope of ATLAS using the weather corrected outputs of the data processing methodology; designated outputs are extended to produce scenario results of future demand and generation up to 2050. More specifically, average, maximum and minimum daily profiles per month (outputs of the EELG model) can be produced and used as they are, or combined outside the model, with full half-hourly through-year historical demand to produce full half-hourly through-year forecasts.

The initial EELG model was delivered in December 2016 and then recalibrated in March 2017. The long-term forecasting scenarios for P demand from the EELG model were combined with information on major demand, generation and storage connection projects to better model short-term certainties (ie, 1-4 years in the future) on local effects from these projects on demand and generation levels.

In contrast, the Q scenario methodology has been developed internally by Electricity North West using a group of interoperable programming scripts that allow big data analytics and time-series network modelling for the whole of the EHV network. More specifically, the IPSA power systems analysis tool, together with Python and MATLAB software platforms, have been used in this modelling, building on the approach developed in the REACT project [1]. Novel approaches in the ATLAS project include the developed methodology to forecast measured Q demand at primary substations by combining the initial P forecast with identified historical seasonal trends of measured Q/P ratios at primary substations.

Between primary substations and GSPs, time-series modelling of the EHV network is used to simulate the interactions between power flows and the network characteristics (ie, asset properties, network configuration, operational aspects such as voltage targets etc). A significant achievement for the ATLAS project this year was the set-up and validation of this network modelling against monitored Q demand across all Electricity North West's GSPs. The draft Q forecast models were then completed in March 2017. The implementation and practical benefits of the proposed Q forecast methodology were presented at the June 2017 CIRED conference in Glasgow [3].

Further to this detailed time-series network modelling approach to forecast Q demand, a simplified empirical approach was developed and compared with the detailed approach. The empirical approach also used full half-hourly through year inputs, but used empirical rules to model the interactions of local mixes of demand and generation with EHV networks. This comparison revealed that the network modelling is superior in terms of more accurately reflecting the effects of these interactions between demand and generation on Q demand and that this approach allows network modelling improvements (eg use of more accurate cable susceptances) to mimic the performance of T-D interfaces in terms of Q exchange profiles. Nonetheless, it was recognised that the simplified empirical approach could offer benefits if used by National Grid as it enhances the approach currently followed by the TSO to forecast Q demand at GSPs.

In 2017, a set of five scenarios were developed for the grid & primary network combining the P and Q results with Central Outlook used for the purposes of Week 24 reporting to National Grid, Load Index reporting to Ofgem and Long Term Development Statement reporting to stakeholders. The full scenario set (Central Outlook, Green Ambition, Active Economy, Focus on Efficiency and Slow Economy) was developed to identify true demands for network planning in ENA ER P2/6 planning standard for GSPs, BSPs, primaries and demand groups.

To extend the use of demand forecasting results from periods of peak demand to minimum load conditions, a metric to estimate available thermal capacity for new DG connections was produced. Using the minimum demands and installed/accepted DG capacity values gathered as part of the ATLAS project, this metric was produced by BSP substation to indicate the available capacity for EHV and HV DG connections. Combined with information on fault-level headroom, this is being taken forward through internal then external consultation in 2018 as an output beyond ATLAS.

In relation to the third success criterion, a new internal policy document reflecting the ATLAS approach to the annual update of demand and generation scenarios was adopted in January 2018. The ATLAS methodology was also extended to allow forecast and weather-correction of units distributed by the network, to enable ATLAS to deliver across both network planning and pricing functions in BAU.

The 2017 true demand scenarios from the ATLAS project were also successfully adopted as part of Electricity North West's Real Options Cost-Benefit-Analysis model [12], which enables the cost and network risk of investment decisions between DSR and traditional reinforcement solutions on the grid & primary network to be assessed in the context of demand uncertainty.

The final phase of the ATLAS project has been preparing for implementation of the ATLAS methodologies in BAU in the forecast and reporting of grid & primary loads for the purposes of Week 24 reporting to National Grid, Load Index reporting to Ofgem, Long Term Development Statement reporting to stakeholders and identifying true demands for network planning to the ENA ER P2/6 planning standard. As part of this, consistent substation naming and connectivity for the purposes of load reporting has been implemented across all of these reports and an increasing number of input data systems. Specifically, the P and Q forecast models have been updated with the latest network connectivity and customer numbers for 2018, and updated electric vehicle and heat pump uptakes, ready for BAU application in 2018.

In relation to the fourth success criterion, a new methodology was defined to run the company's existing Future Capacity Headroom model consistently with the 2017 ATLAS demand scenarios for the grid & primary network. Results for the secondary network were produced for Central Outlook and Green Ambition scenarios. This methodology also informed a high-level scope for a future tool to indicate loading versus capacity on the secondary networks. This will build on the ATLAS scenario approach but will be using the improved baseline loading information available from 2019 as part of Electricity North West's new network management system.

8 THE OUTCOME OF THE PROJECT

8.1 Summary of outcome

The ATLAS project has developed credible methodologies and associated prototype tools for the long-term forecasting of active and reactive power demand and generation across Electricity North West's G&P networks.

The following works on methodology and associated applications have been disseminated and are publicly available on the project's website:

- Data processing methodology (can be used to assess historical active power demand data and estimates of non-monitored generation) [2]
- Insights and explanations on the developed forecasting methodologies presented at the Low Carbon Networks & Innovation conferences in 2016 and 2017
- Demonstration of the time-series network modelling part of the long-term reactive power forecasting methodology (paper published at the CIRED conference) [3]
- Peak demand forecasting results published in the November 2017 LTDS submission
- Closedown report describing the scenario-based demand and generation forecasting methodologies.

The prototype tools produced as part of the ATLAS project have started to be used within Electricity North West in 2018 for business as usual processes which include:

- Data processing and non-monitored DG estimate tools developed in MATLAB software
- Element Energy Load Growth (EELG) model in Excel-VBA format (P scenarios for demand, generation and storage)
- Time-series network modelling tool for Q forecasting using modules developed in IPSA, Python and MATLAB software platforms
- Empirical Q forecasting tool produced in Excel.

8.2 Overview of ATLAS

The ATLAS project has developed methodologies and associated prototype tools for the long-term demand and generation forecasting of the G&P substations (ie GSP, BSP and primary substations). The methodology is used to define five scenarios and associated per scenario outputs (ie MW, MVAr and combined MVA) of true, latent and measured demand per GSP, BSP and primary substation.

The ATLAS project recognised that network planning decisions should consider not only peak demand forecasts (in MVA), but also scenario forecasts focusing on minimum demand (eg, used for DG connections), profile characteristics (ie, load factor assessments to define network asset ratings) and reactive power flows during periods of peak and minimum demand (ie, to assess the effects on available transformer tap headroom and Q exchange interactions with the TSO).

It also recognised that practical reasons derived from modern challenges in distribution network planning have necessitated the requirement of time-series outputs (ie half-hourly) for demand and generation forecasts. For example, when focusing on forecasting P demand, it is the profile characteristics of LCTs that can shift the time that peak demand occurs at a substation. It is also the combination of maximum generation with minimum demand (in MVA) that can define the available thermal capacity for new generation connections. Moreover, when it comes to forecasting maximum VAr exports from distribution to transmission networks (ie, affecting transmission voltages during periods of minimum load), these exports do not coincide with the time of minimum P demand.

ATLAS built on the previous approach followed by Electricity North West to forecast peak demand. It also used the expertise of Element Energy Limited (EE) to utilise domestic and I&C customer data in a bottom up modelling approach that was previously developed by EE to produce load growth models for Northern Powergrid and UK Power Networks.

The forecasting tools for P demand and generation of the proposed ATLAS methodology:

- Use weather corrections and time series (ie half-hourly) analyses and outputs
- Use the learning from the Demand Scenarios NIA project in the Element Energy Load Growth (EELG) model by considering demographic and economic differences per local authority and the way that domestic heat pumps and air conditioning can affect winter and summer peak loads
- Incorporate in the EELG model population, economic growth, consumer choice modelling, changing building stock and demographics; and consider energy efficiency improvements, the profile characteristics of LCTs and new technologies
- Take into account accepted connections of demand and DG (outside the EELG model).

ATLAS also produced a methodology and associated tools for the forecasting of Q demand which builds on the REACT project [1] by:

- Starting from the forecasting of Q demand at primary substations by combining identified historical seasonal Q/P ratio trends (individual trends for peak and minimum demand) with P demand forecasts
- Moving to the Q forecasting at GSP and BSP substations using time-series modelling of the whole of the EHV networks and proper network modelling adjustments (further to the ones followed in REACT).

8.3 Data processing

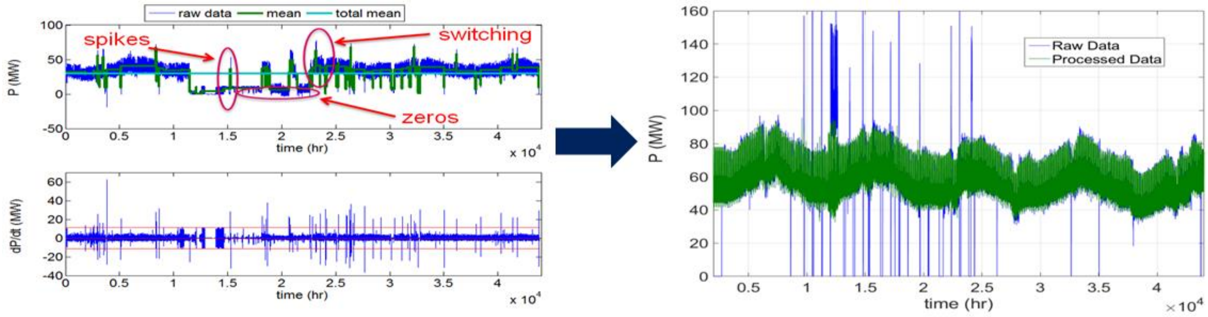
The scenario-based demand forecasting methodologies developed in the ATLAS project use monitoring data at GSP, BSP, primary substations and DG units to first identify the monitored component of historical true demand (ie excluding any effects from non-monitored generation). Having assessed this monitored component of true demand (in MW per half-hour), the data processing methodology developed in ATLAS can be used to adjust this time-series MW data that might be erroneous, missing or not representative of the actual demand of a substation or group of interconnected substations.

The key characteristics of the data processing methodology developed in ATLAS are that:

- It involves half-hourly and daily analyses to deal with monitoring data issues including step changes from switching operations and network reconfigurations, missing and/or erroneous data (eg, half-hourly spikes and/or dips)
- It is generic and can be applied even without any extra network connectivity data
- It allows minimum recalibration when applied to GSPs, BSPs or primary substations
- It has a modular structure that provides flexibility in its use (eg selection of smoothing of demand oscillations and/or purely half-hourly analyses).

As shown in Figure 1, the proposed methodology can identify and correct any demand data issues (eg, spikes, missing data, demand changes due to switching operations).

Figure 1: Data processing tool: identification and correction of half-hourly P demand data.



The ATLAS data processing approach has been applied successfully to process and improve a five-year period of half-hourly P demand data of over 70 BSP and 380 primary substations at Electricity North West.

The developed prototype tool of the proposed data processing methodology was further used in the ATLAS project to:

- Support the identification of historical trends of P demand, during periods of peak and minimum load using different periodicities (eg seasonal trends or individually per month)
- Provide a representative set of daily half-hourly demand profiles across all (or most) Electricity North West GSPs, BSPs and primary substations as the basis for scenario development and network modelling.

The detailed data processing methodology [2] can be found on the ATLAS website.

The same document describes the approach developed in ATLAS to assess the final view of historical true demand by estimating the:

- *Non-monitored DG*: this corresponds to the estimated half-hourly latent demand (generation) of all DG sites without monitoring of export. The estimate is made by combining the capacity, DG type and a generation profile for the appropriate DG type. In the absence of any data on the output of these generators, the estimates are based on individual profiles per DG type.
- *Effects of DG with export metering on reducing customer demand:* given that many DG units are installed on sites with underlying demand (eg, a factory with an installed CHP unit), in many cases the actual generation profiles cannot be derived using the available monitoring export and import data. This component estimates the effects of these generators on masking the underlying true customer demand. The methodology to estimate this effect takes into account the capacity factor of generators (ie historical data used from DUKES statistics), the capacity factor of monitored exports and the limitation of maximum contracted MVA import on the site.

8.4 Weather-correction of true demand

Having processed the time-series demand data and assessed the final view of true P demand as described in the previous subsection, the introduced weather correction methodology can then modify this demand data to represent the load that would have been observed under average weather conditions. This approach was developed and implemented in the ATLAS project by Element Energy using the time-series true P demand data.

In order to correct the load observed on a given day to a long-term temperature average, a correlation between daily total consumption, daily mean temperature and number of daylight hours has been established. A long-term average (LTA) temperature baseline has also been created using a ranked daily mean temperature approach. This temperature is assessed from 30 years of historical hourly temperature data ordered within each month from the warmest to the coldest day. So, the ranked daily temperature comes from the 30-year average for each ranked day.

Following this method:

- The true demand data are corrected to an average year. The annual and monthly average in the established LTA match the corresponding average temperature across the 30-year reference data. More practically, the k-th warmest day of the n-th month will be corrected considering the k-th warmest day of the same month within the 30 years historical data
- Natural variations within the observed temperatures are maintained. This in practice means that hot/cold days will not be pushed to a monthly average
- The difference between observed and historical reference temperature is minimal. This leads in slight manipulation of the true demand data.

8.5 Long-term forecasting of true active power demand and generation

Moving from historical to the future demand, the ATLAS project has developed a scenario based methodology for the long-term forecasting of not only true P demand, but also generation and storage.

The following subsections describe the rationale of our forecasting scenarios, as well as the required inputs and the methodology followed to forecast true P demand for every scenario.

8.5.1 Rationale of developed forecasting scenarios

Given that in reality an accurate assessment of future demand and generation might not be feasible when long forecasting horizons are examined, it is crucial that forecasting scenarios can effectively frame the associated uncertainties in future domestic and I&C demand, as well as future penetrations of different DG types.

To deal with them, each of the ATLAS forecasting scenarios represents a potential future view of the world. These scenarios reflect long-term effects related to economic activity, demographics, energy efficiency and uptake of low carbon technologies. To reflect mid-term increases in loading in a specific development area, connections activity (ie additional loads, DG and storage installations) is also considered to reduce associated uncertainties over the next 1-4 years.

Any or a combination of the forecasting scenarios can be used to justify network planning decisions as any scenario could correspond to a future view of the world in terms of financial affordability, policies supporting renewable generation and energy efficiencies etc. Nonetheless, it is recommended that all scenarios are used in network studies, as well as cost and risk assessments to facilitate informed and well justified decisions in network planning. This recommendation is currently followed by Electricity North West as part of its ROCBA tool [12].

8.5.2 Data requirements

The baseline data gathered and analysed by Electricity North West and Element Energy (EE) are:

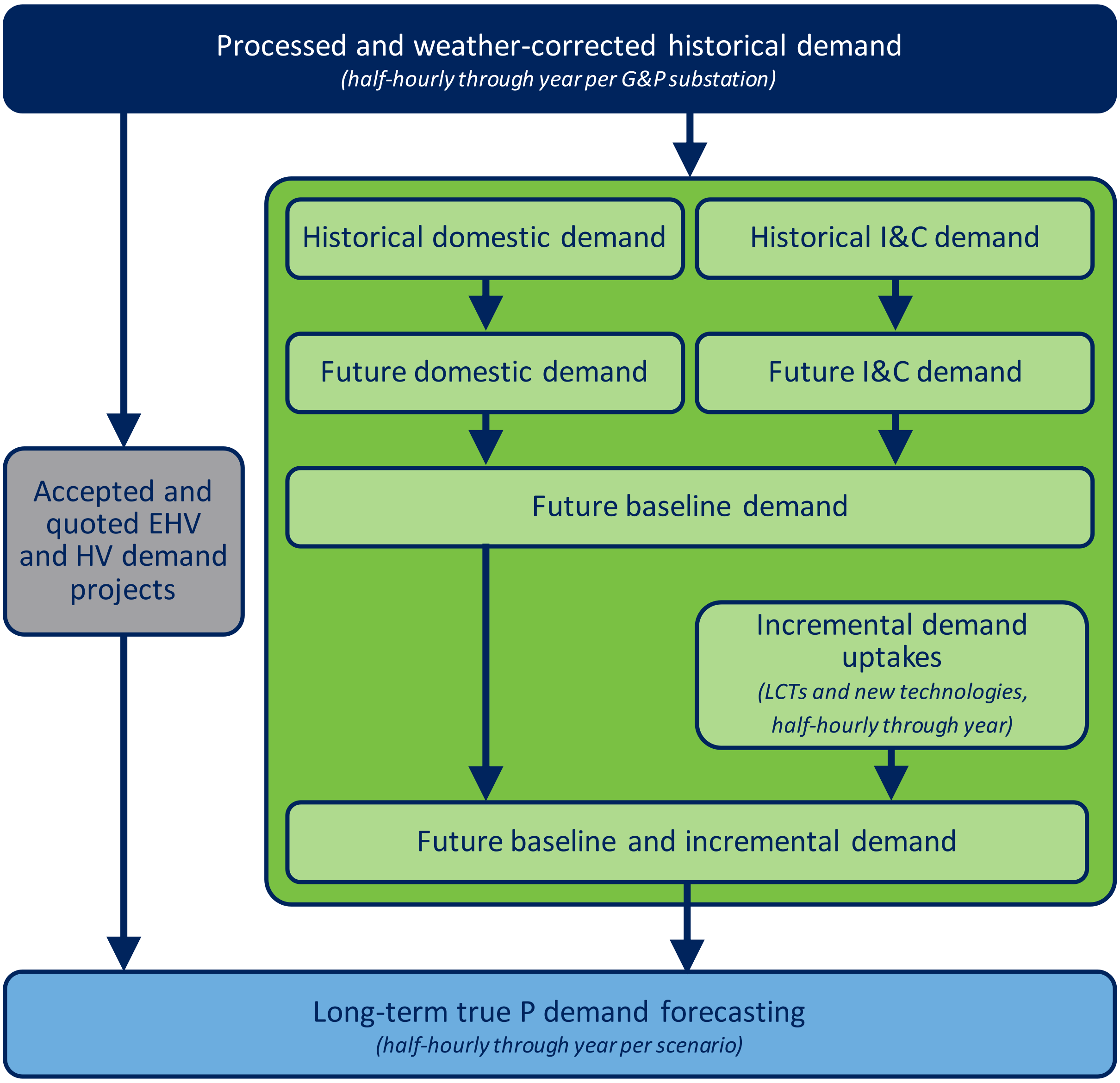
- Network connectivity information, post code and customer counts/types by asset (at HV feeders below primary substations)
- National and local authority uptake plans for LCTs (eg DVLA data for EVs)
- Five years of half-hourly processed true demand data per GSP, BSP and primary substation, as well as interconnectors
- Historical hourly weather data (for two locations, correlated with the five years of demand data, but temperature history considered for the last 30 years)
- Energy units across customers

- DG database (ie ~35,000 DG units for the Electricity North West license area)
- Available thermal capacity for generation per BSP
- Aggregate energy units (ie in MWh) suppressed by non-domestic CHPs
- Profiles for demand LCTs (EVs, HPs), new technologies (air conditioning) and DG types (PV, wind farms, small/medium/large CHPs, flexible generation)
- Household stock growth projections for each local authority (ie from the of Communities and Local Government)
- Scenario data describing appliance efficiency improvements, stock fabric efficiency improvements (from the Market Transformation Programme and EE's housing stock model)
- Historic trends in GVA, number of jobs and floor space in the North West of England
- GDP growth scenarios (from OBR)
- Scenarios for I&C energy efficiency improvements by category (eg heating, lighting etc) according to analysis by the Carbon Trust and consistent with EU energy efficiency targets.

8.5.3 Forecasting true demand

The first step to assess future true demand per scenario is to weather-correct and decompose processed historical demand to domestic and I&C demand components, as shown in Figure 2. As described above, the true demand assessment is done internally by Electricity North West using the data processing tool and the estimation of non-monitored generation. The produced time-series true demand data is then weather-corrected by Element Energy to produce the historical demand data background (ie, half-hourly through year per G&P substation).

Figure 2: The ATLAS methodology for long-term forecasting of true P demand.



Element Energy uses the weather-corrected time-series historical data with yearly consumption data (ie in MWh) for domestic and I&C customers and customer counts per type and substation to decompose demand in domestic and I&C components.

The domestic demand is then projected in the future as an output of the EELG model taking into account:

- The change in number of households (household stock growth)
- The change due to new builds and stock evolution (including effects from local demolition rates)
- The change due to appliance demand per household (effects from appliance efficiency and building fabric efficiency)
- The change in non-appliance domestic demand per household
- The changes in electric heating demand per household (ie taking into account building fabric efficiencies and heating demand trends).

Respectively, the I&C demand is also projected into the future (EELG model) taking into account:

- The change in building stock and floor space (effects from future GVA trends, job numbers etc)

- The change due to new builds and stock evolution
- The change due to energy efficiency improvements (per building and floor space).

The composition of the future domestic and I&C demand results in the long-term forecasting of the baseline true demand. Next, incremental uptakes in demand from LCTs and new technologies are superimposed on the baseline true demand taking into account the per technology profiles for:

- New electric vehicles (ie plug-in hybrids, purely electrical and range extender vehicles)
- New heat pumps (ie air and ground sourced, as well as hybrid HPs)
- Air conditioning (ie domestic and I&C).

It should be noted that the ATLAS form of the Element Energy model uses the learning from the Demand Scenarios NIA project by considering demographic and economic differences by local authority and the way that domestic heat pumps and air conditioning can affect winter and summer peak loads.

For every scenario, the output of the EELG model is the long-term view (ie, extended until 2050 to meet the wider scope of the ATLAS project) of half-hourly future true demand per G&P substation. These outputs can then be combined with information around accepted and quoted EHV and HV demand projects to derive the final forecasting of true P demand. Given the uncertainties on the amount and extent that these projects proceed (usually within a 1-3 year horizon), confidence factors per scenario are considered.

These confidence factors take into account the following assessments:

- Historical statistics about materialized contracted demand from HV demand projects (ie industrial sites are expected to materialise a higher percentage demand of the contracted compared to commercial projects)
- Historical statistics about the percentage of quoted HV demand projects that were finally connected.

8.5.4 Forecasting latent demand

Unlike true demand, the decomposition of historical latent demand cannot be used to forecast future installations of DG units. Rather certainties and uncertainties around future financial affordability and policies supporting the penetration of different DG types need to be considered.

Regarding the future trends in installed capacity per DG type, the EELG model produces a latent demand forecasting taking into account:

- The fact that <=5 and >5MW solar PV and wind DG units currently benefit differently, ie from the Feed-in Tariff (FiT) scheme and the Contract for Difference (CfD) schemes, respectively
- The cuts in FiT tariff are expected to reduce the number of future installations
- Uptakes in CHPs (from mini to large) using an extensive consumer choice model
- Uptakes in biomass, hydro, biogas and waste incineration based on future projections from the historical trend (up to a certain year and then keeping it constant)
- Uptakes in flexible generation driven by different markets (ie traditionally short-term operating reserve, but now the capacity market) and allocation considers available thermal capacity for DG per BSP.

Similarly to the true P demand forecasting, accepted generation connection schemes are superimposed to the EELG outputs to derive the final forecasting of half-hourly generation.

8.5.5 Approach to storage – effects on true and latent demand

Storage units can operate in charging and discharging mode, thus resulting in half-hourly profiles of P imports and exports at the network nodes where they are connected. Consequently, they can in practice affect the forecasting of both true and latent demand.

This is something that was modelled in the ATLAS project and resulted in updates in Electricity North West's Electricity Policy Document (EPD) 289 on annual demand and generation scenarios for long-term forecasting [4]. In this policy update, the true demand is now defined as the summation of:

- The measured demand (ie what is monitored per asset)
- The latent demand (defined below and mainly consisting of generation)
- The storage demand as a negative value (ie P imports to the storage units from the network).

The above definition includes the storage demand, but the storage generation (ie P exports from the storage unit to the network) is considered in the latent demand. As defined in ENA ER P2/6 [5] and ETR 130 [6], latent demand is the demand that would appear as an increase in measured demand if the DG within the network was not producing any output. By treating storage generation as any other DG operation the effects from storage are considered in the latent demand definition.

In ATLAS forecasting of energy storage, the following three types are considered in the EELG model:

- Domestic storage with solar PV
- I&C storage behind the meter
- Storage used for frequency response services.

The consumer choice model developed by Element Energy is considered for domestic storage only. Revenue streams modelling (eg capacity market, TRIAD avoidance, STOR) has been adopted for I&C storage. Finally, historical variations in the grid frequency profile have been used to define the half-hourly performance of frequency response storage.

8.6 Long-term forecasting of reactive power demand

DNOs traditionally carry out studies focusing on periods of peak load. Nonetheless, given the acute declining trends of Q demand across the UK and other European countries during periods of minimum load, DNOs are seeing real voltage containment challenges within their networks (eg currently experienced as reduced transformer tap headroom) with the additional technical challenges of complying with any potential regulatory requirements (eg deriving from the implementation of the European Demand Connection Code [7]).

The following subsections first present the approach developed in ATLAS to forecast Q demand at primary substations. Next, the network modelling approaches to extend forecasting at GSPs and BSPs is explained and a comparison between a detailed time-series network modelling and an empirical rule approach (both produced in ATLAS) is demonstrated. Finally, the advantages of Q demand forecasting carried out by DNOs are drawn.

8.6.1 Forecasting Q demand at primary substations

Although the ATLAS project acknowledges the significant network effects on Q demand with the development of both detailed time-series network modelling and empirical rule approaches for the EHV network, any network modelling below primary substations was neglected. Nonetheless, the historical Q/P ratio trends at primary substations were assessed to provide an improved understanding closer to customer demand.

The future Q demand at primary substations in the ATLAS project is assessed taking into account:

- The forecasting results of measured P demand at primary substations (ie per scenario as the combination of future true P demand and generation)
- That the historical Q/P ratio trends of primary substations continue with the same pace in the future.

The implementation of this approach involved seasonal and individual trends of the historical Q/P ratios at primary substations independently for time-windows of peak and minimum demand.

8.6.2 Forecasting Q demand at GSPs and BSPs

The significant effects of the interactions of demand with EHV networks on the overall measured Q demand at T-D interfaces have been highlighted and quantified in the REACT project for GSPs across all DNOs [8]-[9]. The ATLAS project has built on the REACT modelling approach, but a) made the proper connection with the developed P demand forecasting; b) enhanced the validation process; and, c) applied extensive network modelling to cover the whole of Electricity North West's EHV network.

In the ATLAS project two different approaches were followed to assess the effects of EHV networks on the Q forecasting of GSPs and BSPs:

- Approach #1: using detailed time-series network modelling (TSNM) for the complete EHV network model
- Approach #2: using empirical formulas and network data.

ATLAS has compared how accurate and easy to apply both approaches are, in order to make a recommendation regarding a suitable business-as-usual approach for Q forecasting.

Detailed TSNM tool

Focusing on the assessment of measured Q demand at GSPs and BSPs, the detailed time-series network modelling (TSNM) approach requires the use of half-hourly measured P and Q demand data of all associated primary substations in daily time-series power flow simulations. Similar to the REACT project, operational settings (eg substation voltage targets, on-load tap changer tap delays etc) are included in the modelling.

Nonetheless, the following updates from the REACT project regarding the validation process can be summarised in ATLAS:

- Any network components (eg, cables, transformers) behind the metering point of offshore or other large generators needs to be excluded from the network models as they can affect Q flows within the networks (ie, REACT excluded any GSP groups with significant EHV generation, whereas ATLAS validated all GSP groups across Electricity North West)
- In REACT a generic approach to update all EHV circuit susceptance values to mimic Q profiles at GSPs was developed. However, in ATLAS it was identified that the use of typical susceptance values for 132 and 33kV or the erroneous assumption of cable insulation can lead to significant inaccuracies and therefore the susceptance values of these elements should be better modelled, rather than apply changes to overhead line parameters.

The TSNM tool was first validated using historical monitoring data (ie half-hourly P and Q data). Input data for the validation process are the EHV network planning model (ie currently modelled using IPSA software) and the half-hourly monitoring data (ie SCADA data) for measured P and Q demand across G&P substations. A series of other interconnected components (ie MATLAB scripts for data processing, Python scripts for time-series power flows) allow the derivation of half-hourly simulation results. These results are then compared against monitoring data (process done by GSP group) to validate the TSNM tool.

After the validation process, the tool can be used to forecast Q demand at GSP and BSP substations. To do this, the validated network model is used in times-series simulations with half-hourly:

- Future measured P and Q demand at primary substations
- Historical measured P and Q demand at large EHV demand and generation sites
- Future large EHV connected demand and generation.

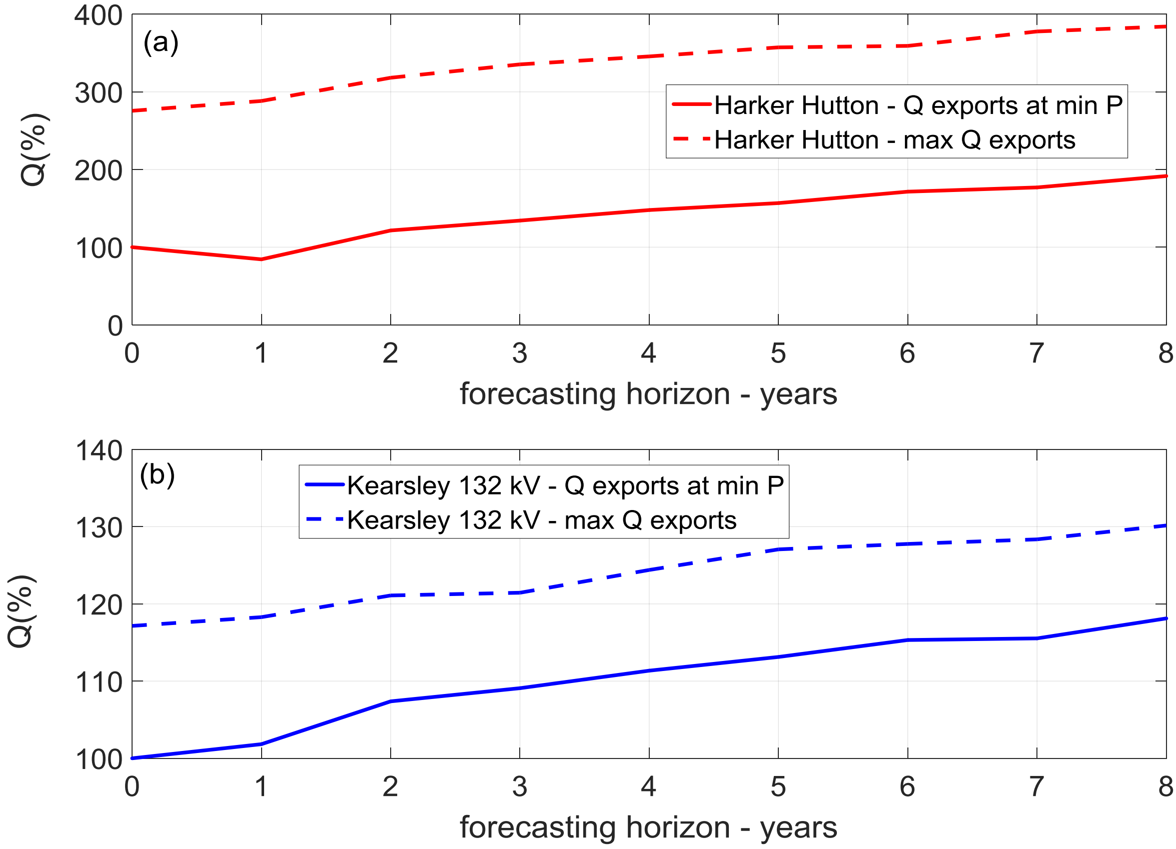
To better understand the benefits from time-series analyses, Figure 3 illustrates the TSNM tool results for future Q exports to transmission for two GSPs over an eight-year horizon (ie year 0 corresponding to financial year 2017). The two trends presented for each GSP correspond to:

- The Q exports at the time of the annual minimum P
- The maximum Q export value per year identified per year taking into account all half-hourly results of that year.

It is clear for both GSPs in Figure 3 that maximum Q exports to transmission are considerably higher than the Q exports at the time of minimum P. For the Harker-Hutton case this involves a significant amount of DG capacity; the minimum P can correspond to times of significant local reverse power flows that result in high VAr absorptions in parts of the EHV network. This explains not only the lower Q exports to transmission at time of minimum P in year 1 compared to year 0, but also the significant percentage difference of the two trends.

For the Kearsley GSP case in Figure 3, it is evident that although this GSP group does not involve significant amounts of installed DG capacity (as it is an urban and sub-urban network) it is the interaction of demand and generation mixes with regional parts of the associated EHV network that can lead to a significant increase in max Q exports from the VArs exported at the time of minimum load.

Figure 3: Future trends of Q demand as a percentage of year 0 (ie 2017) max Q exports to transmission at the time of min P. Results presented for a) Harker-Hutton GSP; and, b) Kearsley 132kV GSP.



Empirical rule

To justify the necessity of the detailed TSNM approach to forecast Q demand, an empirical rule was also developed and associated results were compared. The empirical rule is based on several simplifications and thus leads to less accurate results. Appendix 16.2 describes this methodology in more detail. Although this approach is less accurate and still uses a lot of data (ie same amount of half-hourly demand and generation forecasts), it can:

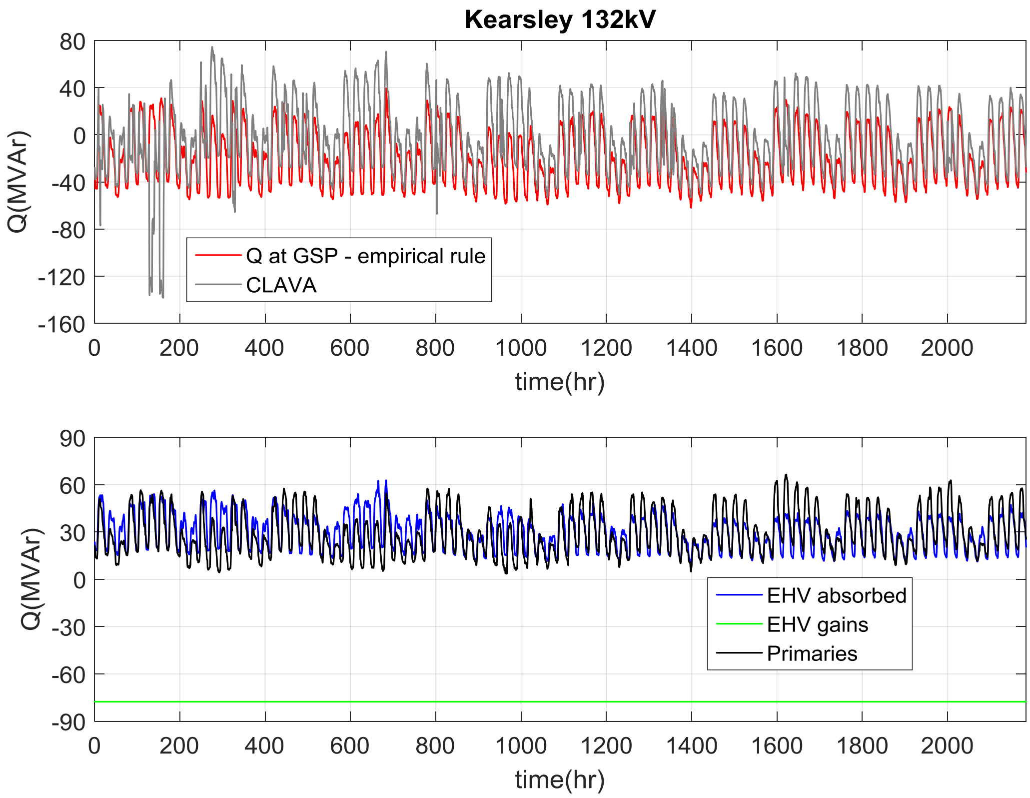
- Be used more easily by National Grid (or other DNOs) to improve their existing Q forecasting approaches
- Be used as a straightforward way to decompose overall Q demand at GSPs into three components:
    - the monitored Q demand at primary substations and EHV generation
    - the Q absorption across EHV transformer and circuit reactances
    - the Q gains from EHV circuit susceptances.

This decomposition of Q demand is shown in Figure 4 for Kearsley GSP. The EHV absorbed VArs and the Q demand at primaries (no EHV generation here) shown are the Q components that define the profile shape of the overall Q demand. The EHV gain in VArs, however, is the component that leads to negative values in overall Q demand. Therefore, how negative the Q demand is at a GSP (or how significant the VAr exports to transmission are) is defined by the combination of:

- How significant the Q gains are depending on EHV circuit lengths and amount of cables
- How lightly loaded the EHV network is and therefore how reduced the VArs absorbed in the EHV network are

- How close to 0.95 lead/lag conditions the EHV connected generation operates and what is the associated range of Q exports/imports
- How inductive or capacitive the demand of primary substations is.

Figure 4: Half-hourly Q demand at Kearsley 132kV for April to June 2016. a) Upper graph: comparison between empirical rule and monitoring data (CLAVA) for the Q demand at Kearsley 132kV. b) Bottom graph: Q components of the empirical rule.



Comparison of the two Q forecasting approaches

The mismatches/inaccuracies when the empirical rule is adopted to forecast Q demand compared to the detailed TSNM tool are due to:

- The fact that the empirical rule is tailored to radial networks and does not model any 132 and/or 33kV meshing in distribution networks
- The empirical rule considering equal loading of 132 and 33kV circuits under GSPs and BSPs, respectively. This approximation is not realistic and can lead to lower or higher mismatches in VArs absorbed on transformer reactances at BSP and primary substations, as well as line and cable reactances of the 132 and 33kV circuits
- Constant voltages (rather than time-varying due to network loading and OLTC operation) being taken into account in the assessment of VAr gains from 132 and 33kV underground cables and overhead lines.

A detailed comparison between the TSNM tool, the empirical rule and monitoring data is presented for Kearsley 132kV GSP in Appendix 16.3.

It should be highlighted that it is only by using the TSNM approach that any potential poor modelling of critical network components or other modelling/data issue to assess Q demand at T-D interfaces can be identified. A generic process to update 132 and 33kV susceptances was first demonstrated in the REACT project. In ATLAS an improved approach is used which considers:

- The constant (dc component) difference between simulation results and monitoring data for Q demand at a GSP
- A static calculation of Q gains from 132 and 33kV cables.

Following this approach, the 132kV cable susceptance values for cable dominated networks (eg South Manchester GSP) were identified and improved. Further checks on these values revealed that although typical susceptance values were used for oil insulated cables, these were slightly different from actual values and in other cases replaced with new XLPE insulated cables with poor update of associated susceptance changes.

Any Q flows in the EHV part of distribution networks are highly susceptible to voltage fluctuations and power flows close to the T-D boundaries, data quality issues for Q demand monitored at lower voltage levels (eg primaries) and network data (eg changes in BSP transformer reactance values with time). In practice it is difficult to model these aspects. Therefore, the adequacy of a network model to mimic the T-D performance regarding the associated Q exchanges depends in practice on its ability to quantify local network interactions (ie per BSP group with associated 132kV in-feeds) of future trends in demand and generation.

8.6.3 Advantages in Q Forecasting from DNOs

The assessment of the Q/P ratios of the overall demand at the T-D interfaces is an approach commonly followed by transmission operators to understand trends in Q demand during periods of minimum load [10]-[11]. Analyses carried out by National Grid in the UK [10] have shown that:

- There is a continuous decline in the aggregated Q demand at GSPs during periods of minimum load, as well as in the associated Q/P ratio trends
- The time duration of Q flows from distribution to transmission at UK GSPs (VAr exports to transmission) increased from 0% in 2005 to over 50% after ten years (using half-hourly analyses)
- A significant amount of compensation is needed in the future to contain transmission voltage levels as indicated by analyses in both transmission (NG) and distribution (REACT project) network studies.

Although the identification of historical trends in Q demand was feasible for the TSOs, crucially such approaches do not consider the interactions of distribution networks with future mixes of demand and generation connected at distribution voltage levels. This interaction might not be critical in the forecasting of active power (P) demand (ie P losses in distribution networks are limited percentage of the overall P demand), but it has significant effects on Q demand levels at T-D interfaces as shown in both the REACT and ATLAS projects.

Even if the ESO was interested in having a sensible forecast of Q demand at primary substations, the volume of data (eg seasonal Q/P ratio trends) that would be required in analyses and associated tools/expertise on using this data could be a significant challenge. Although the LTDS EHV network data is already collated and published by every DNO, the half-hourly historic and forecast P and Q demand at primary substations (ie ~400 primaries owned by Electricity North West) and large non-domestic demand and generation customers cannot be easily published by a DNO.

More generally, DNOs should be considered in a better position to forecast Q demand at transmission-distribution interfaces (particularly at individual GSPs). When Q forecasting is done by Electricity North West (and potentially by more DNOs in the future) following the ATLAS approach the forecast will be improved because:

- DNOs have a better understanding for their own network planning purposes of existing and future true demand and generation per voltage level and per region (ie with higher spatial resolution), as well as current and future numbers and types of customers (domestic, non-domestic, generation, storage, new technology uptakes).

- DNOs can more accurately quantify the interaction of demand and generation with distribution networks using their latest network models. This involves combining big data analytics (both for network and demand data) and using time-series network modelling instead of the empirical approach reflecting their operational aspects and extending down to primary substations. However, it also involves a better understanding of when and where new demand and generation is connected, as well as operational patterns of existing and accepted customers.
- This can reflect local/regional information, experience and big data analytics associated with demographics, econometrics, locations of new connections, weather-dependence, and technology uptake (eg heat pumps, electric vehicles, air conditioning). DNOs can also use historical Q/P ratio trends closer to demand in their analysis (ie at primaries).

8.7 Forecasting MVA for peak true demand

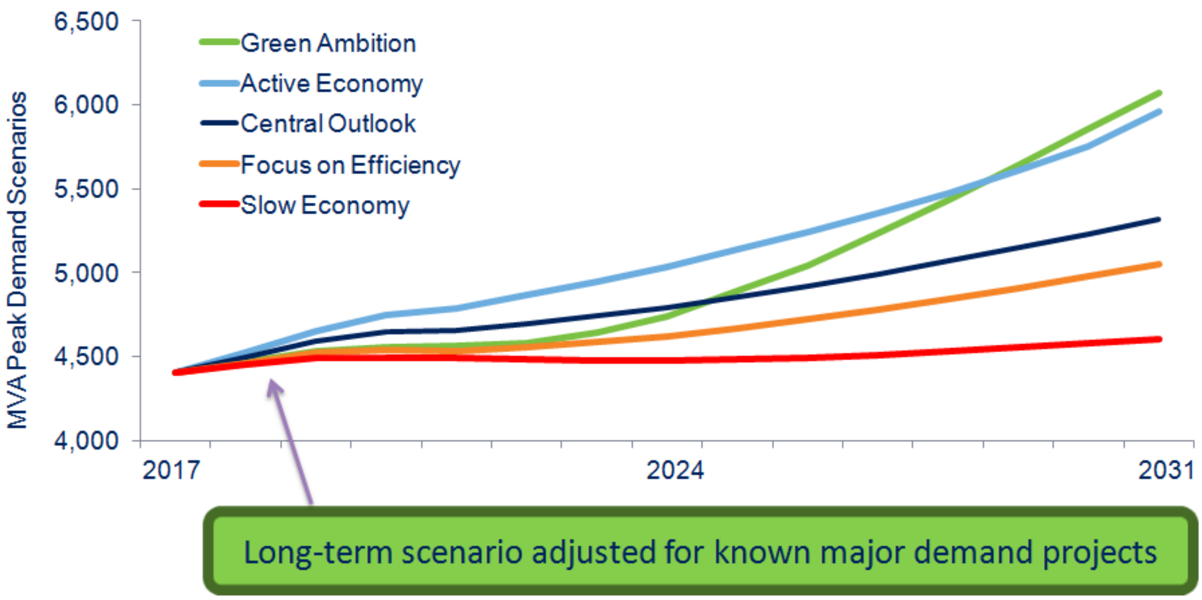
Using the ATLAS approach, Electricity North West has improved the way the peak apparent power (in MVA) is assessed for the different forecasting scenarios. These values are published as part of the LTDS and used for the ENA ER P2/6 assessments.

The apparent power (S) demand corresponding to the peak true P demand is forecasted for each scenario as follows:

- The half-hourly, through future years, true P demand of the examined G&P substation is assessed
- The half-hourly, through future years, Q demand using time-series network modelling for zero generation conditions is assessed
- The half-hourly P and Q demand is then combined to derive the associated half-hourly through future years S demand.

Figure 5 shows the aggregated peak S demand (in MVA) of all BSPs owned by Electricity North West. These results are shown for the different forecasting scenarios using the ATLAS methodology. A more detailed presentation of the Central Outlook results and differences from the other scenarios can be found in the Central Outlook demand forecast overview document on the ATLAS website.

Figure 5: Forecasting peak apparent power (aggregated BSP peaks in MVA) of true demand for the ATLAS forecasting scenarios.



The forecasting results per BSP and primary substation are also used by Electricity North West in the real options CBA (ROCBA) tool [12]. Using all scenarios, the ROCBA tool can support the decision-making process to justify a DSR or traditional reinforcement intervention by providing the associated cost and risk assessments per option across the scenarios.

8.8 Week 24 forecasting

Unlike forecasting S demand for peak true demand conditions for LTDS and ENA ER P2/6 assessments, Week 24 reporting to National Grid is a Grid Code obligation that requires the forecasting at GSPs:

- Of true and latent P demand, as well as the combined measured P demand
- Of measured Q demand
- Not only for peak load conditions (eg for national and GSP peaks), but also for minimum demand conditions.

The ATLAS approach for the Week 24 forecasting revealed some interesting practical insights, such as:

- The time of forecasted peak true demand in some GSPs is different from the requested time for the national demand due to various local factors including the uptake of LCTs affecting the associated profiles
- The forecasted (and historical) Q demand during the time of minimum national demand time is strongly inductive or capacitive in a generation dominated GSP. This depends on whether this generation supplies to a lightly loaded EHV network (capacitive GSP) or significant reverse power flows (inductive GSP).

8.9 Identifying available thermal capacity for generation

The ATLAS project recognised that network planning decisions should consider not only peak demand forecasts (in MVA), but also scenario forecasts focusing on minimum demand. Focusing on future DG connections, it is the combination of maximum generation with minimum demand (in MVA) that can define the available thermal capacity for new generation connections.

Applications for new DG connections typically require minimum reinforcements when thermal capacity for reverse power flows and available fault level headroom are available. Using the developed methodologies for demand and generation forecasting, the ATLAS project has introduced a simple metric to quantify the available capacity for generation and has quantified it per BSP substation.

More specifically, the overall capacity for reverse power needs to be assessed first as the summation of:

- The substation capacity (for N-1 conditions) as the minimum MVA value among the following three factors:
  - transformer rating for reverse power flow
  - circuit breaker ratings
  - incoming feeder ratings
- The forecasted minimum true demand of the substation.

Having assessed the available capacity for reverse power flows, the DG, corresponding to a) already connected projects, b) the accepted for connection projects and c) the long-term generation forecast (from the EELG model), is aggregated. The calculated DG capacities can then be subtracted from the overall capacities for reverse power flow to derive the available thermal capacity for DG per substation and year.

It should be noted that the above-mentioned process should be followed individually for N-1 and N-0 connected generation with consideration on the associated capacity ratings.

This simple metric has been further used in ATLAS to provide extra information on BSPs where flexible generation is more likely to connect in the future. Additionally, this information can be combined with the associated fault level headroom per substation to inform customers on technical limitations, as well as to provide insights in associated cost elements for potential network reinforcements.

8.10 Scoping work on fault-level headroom on the EHV network

As noted in the previous subsection, reinforcement is typically required for new DG connections, not only when thermal capacity for generation is available at a substation, but also fault level headroom. To deal with this the ATLAS project has introduced the concept of fault level headroom (FLH) indicators as a metric to quantify existing and future limitations to connect DG units to G&P substations with minimum potential reinforcement associated with fault levels.

The following indicators are proposed, each showing available FLH for GSP, BSP and primary substations:

- Break FLH: difference in kA between the fault breaking duty of switching devices (or ‘break current’) and the maximum symmetrical rms current at 100 ms after fault occurrence
- Make FLH: difference in kA between the fault making duty of switching devices (or ‘make current’) and the maximum asymmetrical peak instantaneous current at 10 ms after fault
- Design FLH: difference in kA between the network design fault levels (ie can be found for the different voltage levels in EPD 220 [13]) and the maximum symmetrical rms current at 100 ms after fault occurrence.

Break, make and design FLH needs to be assessed not only for the current year (‘as of now’), but also for the future using the generation forecasting. More specifically, the proposed approach in this scoping work is specified to:

- Cluster future generation regarding their contribution to fault currents (ie inverter connected units, synchronous machines etc)
- Follow Engineering Recommendation (ER) G74 [14] in fault level assessments, which meets the requirements of IEC standard 60909 on short-circuit current calculation on ac networks
- Involve fault level assessments using the 132 to 33kV EHV network planning model with simplification assumptions for any future generation connected below primary substations.

8.11 Scoping work on demand forecasting at secondary substations

Since 2011 the FCH model has been used by Electricity North West to estimate future loading of secondary networks and indicate volumes of associated reinforcement needs. This model is linked with other internal systems (eg, load allocation model, automatic restoration system) and uses peak load analyses.

In 2017 the company’s existing FCH model was used with enhanced inputs consistently with the 2017 ATLAS demand scenarios for the G&P network. More specifically, results for the secondary network were produced for Central Outlook and Green Ambition scenarios (ie, peak demand forecasts from ATLAS combined with the load allocation of the FCH model).

Additionally, initial scoping work for an updated FCH tool with enhanced analyses and functionalities has been carried out. This tool should make the best use of the forthcoming

NMS (in place after 2019); the following three options are therefore suggested for the successor model:

- Option #1 – model that does not use any network modelling and is not incorporated into the developed NMS. Connectivity, customer attribution, loading per asset and appropriate ratings data are extracted from the NMS and combined with ATLAS scenario assumptions. Scaling of existing loading and the addition of LCT uptake profiles are summated to compare against ratings.
- Option #2 – model that uses network modelling and is not incorporated to the NMS. The same data extracted from NMS and ATLAS scenario is input to a simplified symmetrical network model (eg using OpenDSS open-source platform developed by EPRI).
- Option #3 – model incorporated into the NMS using ATLAS scenario assumptions. The NMS network model system is used in this option to identify overloads, but accuracy elements and flexibility in modelling should be questioned.

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

Extensions to scope

The timeframe of the forecasting scenarios has been extended, beyond 2030, on an indicative basis to 2050. This longer period is required when considering Ofgem’s CBA framework and for impact assessments for innovation funding.

Accepted and quoted connections were added as they were considered to have significant effects on future demand and generation. It was also recognised that by doing this there was a better framing of the associated uncertainties in the mid-term horizon (ie 1-4 years).

Substation-specific weather correction of demand was adopted as it was recognised that non-localised weather corrections (eg ACS factors from National Grid) cannot explain the regional correlation of historical half-hourly demand with weather data.

Apart from data processing and the effects from monitored generation, it was realised that demand masked by non-monitored generation (eg, domestic PV, micro CHPs etc) and demand suppressed by on-site generation needed to be quantified to identify the true (or underlying) demand.

The initial scope was to provide indicators for available thermal capacity for generation. Recognising the significant effects from the available fault level headroom for new DG connections, scoping work resulted in the high-level definition of a methodology to assess future fault level headroom at the G&P substations.

Changes to approach

Instead of one forecasting tool, two separate prototype tools were developed for the P and Q forecasting scenarios. Components of these tools were developed in MATLAB and Python in order to a) enhance computational performance; b) allow interoperability with other components (eg EELG excel-based model, IPSA power systems analysis tool, databases and internal systems); and, combine results for reporting and further analysis. This approach of separate rather than combined tools was not only more deliverable in the timeframe, but was also chosen to allow continuous and independent per component development by internal and external resources.

10 PROJECT COSTS

Item	Category	Estimated Costs (£k)	Final Costs £k (rounded)	Variance
1	Development of internal ('in-house') methodologies and prototype tools (ie Q forecasting, data processing, estimation of non-monitored generation), internal resources from strategic planning	300.0	130.6	-174.4
2	Development of external methodologies and prototype tools (ie Element Energy Load Growth model and version updates, weather correction work package etc)	240.0	195.0	-40
3	Dissemination costs & IT elements	60.0	33.0	-27
	Total	**600**	**358.6**	**-241.40**

11 LESSONS LEARNED FOR FUTURE PROJECTS

The ATLAS project has so far demonstrated that it is feasible, but challenging, for a DNO:

- To implement half-hourly data processing for GSP, BSP and primary P and Q demand
- To weather-correct true P demand
- To use these inputs as the basis of well-justified forecasting scenarios for true, latent and measured P and Q demand for the purpose of network planning.

Using half-hourly, through year, data inputs and in order to carry out time-series analyses, an automated process for using data from multiple databases was required. Therefore, changes needed to be made for consistency (eg for substation and DG unit naming) in multiple reports and datasets. This has resulted in documenting and sharing internally the allowed G&P substation names and DG types that should be used across different databases.

Significant data analyses, especially when combined with extended network modelling, revealed that special concern should be taken in modelling to deal with issues around computational cost and memory limitations.

12 PLANNED IMPLEMENTATION

The ATLAS project has led to an update in Electricity Policy Document (EPD) 289 'Annual Demand and Generation Scenarios'. Critical updates include the consideration of confidence factors around accepted and quoted demand connections, the adoption of general principles of the ATLAS approach in Q forecasting (eg network modelling, Q/P trends at primaries) and inclusion of energy storage in true and latent demand definitions.

The prototype tools developed during ATLAS have already supported demand forecasting in 2017 which will become business as usual. To achieve this, the EELG model will be recalibrated using up-to-date monitoring, customer and other data, as well as an update of the Q forecasting model using the latest EHV network planning model and updated analyses for Q at primaries.

13 DATA ACCESS

Electricity North West's innovation data sharing policy can be found on our website.

No additional network or consumption data was collected as part of the ATLAS project. The changes in methodology introduced by ATLAS were around how the raw data was processed and combined on an annual basis to identify historical half-hourly true, measured and latent demand, and then to generate future scenarios. Thus there has been no available monthly data to share during the project.

The volumes of processed data in the project are large. Therefore, any requests for data sharing will be assessed on a case-by-case basis against the customer interest.

14 FOREGROUND IPR

Working with Electricity North West, Element Energy Limited used its foreground load growth modelling to develop the Element Energy Load Growth (EELG) model. Therefore, any distribution and use of the EELG model outside Electricity North West is not permitted without the express permission of Element Energy Limited.

15 FACILITATE REPLICATION

Information about the ATLAS project has been shared extensively outside of Electricity North West on our website and through various presentations.

This dissemination activity enables other organisations to assess how they could use the ATLAS approach to load scenarios for themselves. Audiences consisted of other DNOs, National Grid, relevant consultancies, academics and similar international network companies. Further information on the principles of ATLAS is shared as part of this closedown report which will allow DNOs or others to replicate the developed techniques.

ATLAS was presented at two Low Carbon Networks & Innovation (LCNI) conferences. The first presentation was in Manchester in October 2016 (on the Electricity North West stand) and at the end of the project in December 2017 in Telford at the 'Innovation in Electricity Network Design' breakout session.

Project factsheets were produced to accompany both LCNI presentations.

ATLAS featured in Electricity North West's innovation learning dissemination event in May 2017. A paper and poster on 'Long Term Forecasting of Reactive Power Demand on Distribution Networks' were presented at the biannual CIRED conference in June 2017 in Glasgow, while the data processing methodologies were presented at the University of Manchester's MEEPS event in November 2017.

All of the presentations and factsheets mentioned above can be found on the ATLAS project website.

16 REFERENCES/APPENDICES

16.1 References

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[13] Electricity Policy Document (EPR) 220, "Fault Level Management", Electricity North West Ltd, issue 1,UK, 2011.

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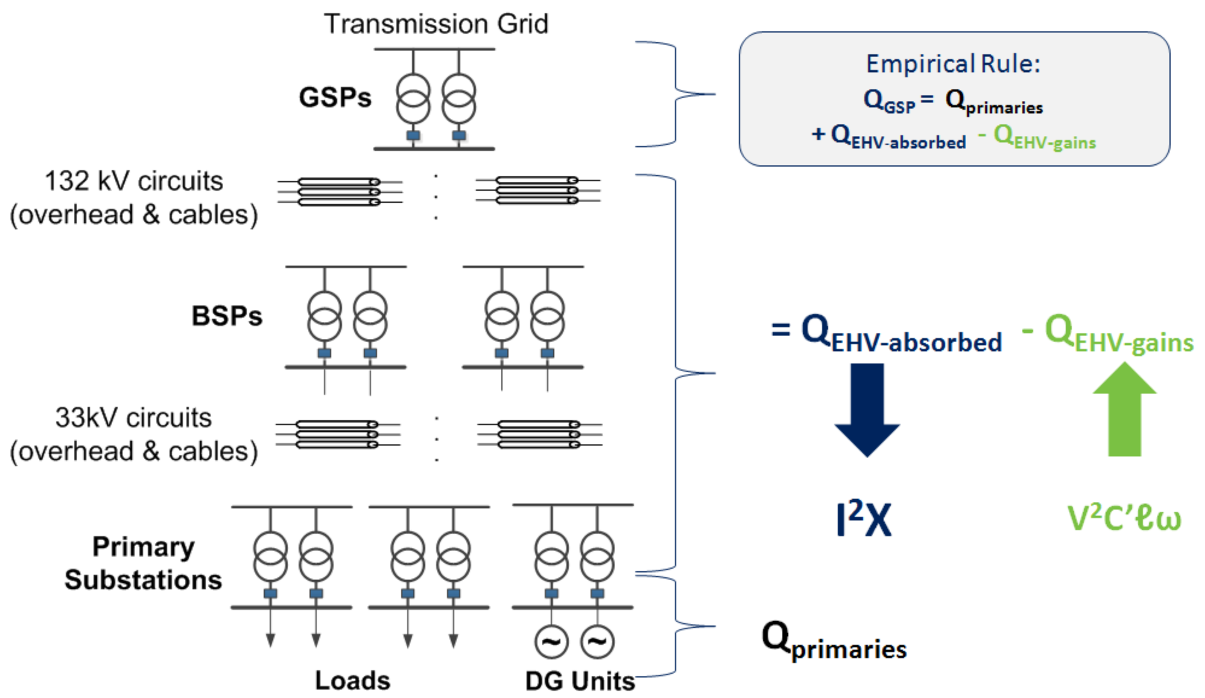
16.2 Empirical Rule in Q forecasting

The developed empirical approach considers an empirical representation of the 132 to 33kV distribution networks and available monitoring and forecasted demand and generation data to produce a half-hourly forecast. This methodology should be used after the forecasting of both P and Q demand at primary substations to forecast the corresponding Q demand at GSP and BSP substations.

Figure 6: The reactive power components of the ATLAS empirical rule for Q forecasting.



As shown in Figure 6, the Q demand at GSPs is suggested to be calculated as:

$$Q_{GSP} = Q_{EHV\text{-}absorbed} - Q_{EHV\text{-}gains} + Q_{primaries} \qquad (1)$$

where:

- Q_{GSP} is the overall Q demand at GSP (ie transmission-distribution interface)
- $Q_{EHV\text{-}absorbed}$ is the VArs absorbed on the 132 to 33kV network reactances (eg on BSP transformers)
- $Q_{EHV\text{-}gains}$ is the VAr gains (or injections to the network) from the 132 to 33kV network capacitances (eg from underground cables).

The proposed rule can be implemented using the following input data:

- LTDS EHV network (ie 132 to 33kV including primary transformers) data
- Forecasted true P demand and generation at primary substations coming from:
  - accepted P demand and generation connections
  - long-term forecasted true P demand and latent P demand (from generation) using ATLAS tools and methodologies (ie Element Energy Load Growth – EELG model)
- Forecasted Q demand at primary substations
- P and Q monitoring data for existing generation and large industrial customers above primaries
- Forecasted P data for future generation above primaries for:
  - accepted DG connections (known projects)
  - forecasted DG installations (longer-term).

NB. Future generation is assumed to connect at unity power factor, so there is no forecast Q associated with generation connected either below or above primaries. However this assumption can be varied and any extra VAr exchanges from DG units can be added as an extra factor (similar to the $Q_{primaries}$ factor).

The future Q demand at GSPs can be assessed using the following steps:

- Step #1: assessment of the EHV network matrix: number of matrix lines is equal to the total number of GSPs. Number of columns (ie 14 columns) corresponding to the following:

  - 132kV lines (columns 1-4): average branch resistance, reactance and susceptance in per unit (ie r,x,b), as well as number of 132kV lines per GSP
  - BSP transformers (columns 5-7): average resistance and reactance in per unit (ie r,x), as well as number of BSP transformers per GSP
  - 33kV lines (columns 8-11): average resistance, reactance and susceptance in per unit (ie r,x,b), as well as number of 33kV lines per GSP
  - Primary transformers (columns 12-14): average resistance and reactance in per unit (ie r,x), as well as the number of primary substation transformers per GSP.

- Step #2: assessment of the aggregated primary P and Q demand per GSP:

  - Primary connectivity: production of matrix showing connectivity of primaries with GSPs
  - P-matrix: assessment of aggregated half-hourly primary P demand per GSP
  - Q-matrix: assessment of aggregated half-hourly primary Q demand per GSP.

- Step #3: production of the simplified per unit network model per GSP:

  - Simplified network consists of four groups as shown in Figure 7, ie 132kV line group, BSP transformers group, 33kV lines group and the primary transformers group
  - The equivalent network model of each group is the parallel combination of r and x values (from Step #1) taking into account the number of parallel branches (eg N_1 number for the 132kV lines as shown in Figure 7)
  - The four groups are connected in series to produce the final simplified network per GSP
  - The per unit aggregated measured demand (p and q in Figure 7) is assessed using the summation of P and Q demand across all primaries of the examined network and the per unit apparent power base – S_b (ie $p=P/S_b$, $q=Q/S_b$).

- Step #4: assessment of the per unit current to assess Q losses per GSP:

  - Reference voltage: v=1 pu at primary substation (this is in line with applied voltage targets)
  - The per unit current at primaries is assessed as $i_{Pry}=s/v=s$. This current is considered to be flowing through the parallel combination of primary transformers and 33kV lines, as shown in Figure 7
  - The per unit current flowing through BSP transformers and 132kV lines takes into account any 33kV connected generation. This contribution is assessed as: $i_{DG,BSP}=P_{DG}/S_b$ and subtracted from i_{pry}

- Step #5: assessment of total Q losses per GSP:

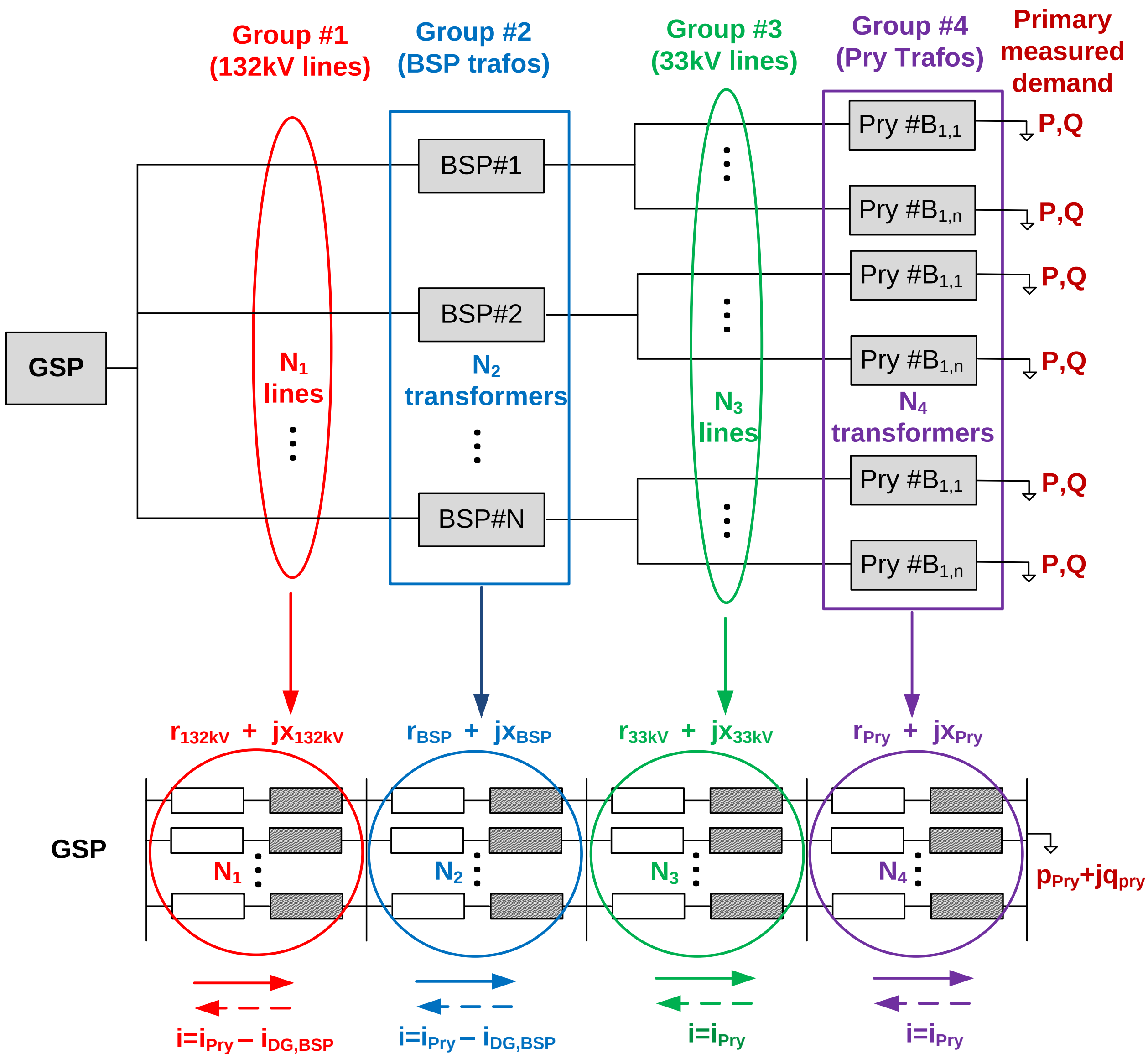
  - This is assessed using the produced simplified network (Step #3) and the currents flowing through every group (Step #4) as shown in Figure 7. It should be noted that equal loading through each branch in all groups is considered (eg N_4 transformers as shown in Figure 7 overleaf, so each primary transformer is feeding $1/N_4$ of the aggregated primary demand).

- Correction for 132kV connected generation: losses on 132kV lines are affected by the output of 132kV connected DG units. The number of generators connected at 132kV and the total output are assessed and considered to be connected to an equal number of 132kV lines in the simplified network of Figure 7. The correction on Q losses on 132kV lines can then be assessed. More specifically, this correction for a number of N_{DG} generators connected at 132kV in the examined GSP group is taken into account.
- The total per unit Q losses can be calculated using the following equation:

$$q_{losses}=(i_{Pry}-i_{BSP,DG})^2\cdot(x_{132kV}\cdot N_1+x_{BSP}\cdot N_2)+i_{Pry}^2\cdot(x_{33kV}\cdot N_3+x_{Pry}\cdot N_4)-i_{DG}^2\cdot x_{132kV}\cdot\frac{N_{DG}}{N_1}$$

- Step #6: assessment of total Q gains per GSP:
  - This is a static calculation that provides a constant value per GSP (not varying with time)
  - The average voltage target value is assessed for BSP and GSP transformers (v_{BSP} and v_{GSP} respectively)
  - The Q gains are assessed as follows:
    - $q_{gains} = v_{BSP}^2 b_{33kV,lines}\cdot N_3 + v_{GSP}^2\cdot b_{132kV,lines}\cdot N_1$
- Step #7: final assessment of Q demand at GSPs:
  - Having assessed the Q losses and gains in Steps #5 and #6, respectively, the overall Q demand at GSP is calculated using the following equation that transfers per unit quantities to overall MVAr at the GSPs:
    - $Q_{GSP} = (q_{Pry} + q_{losses}+q_{gains})\ S_B$

Figure 7: Simplified per unit network per GSP to assess Q losses on lines and transformers.



16.3 Validation of Q forecasting tool

This section provides some insights on the validation process of the TSNM tool for Q forecasting. The analysis focuses on Kearsley 132kV GSP group; results from the TSNM tool are compared against monitoring data and the empirical rule.

Figure 8 shows this comparison for Kearsley 132kV for one week in May 2017. It is evident that:

- The aggregated primary Q demand is much lower than the corresponding demand at the GSP in both approaches (TSNM and empirical). Given that this GSP group mainly supplies urban areas and does not include a significant amount of connected DG, it is evident that the effects of the interaction of demand with EHV network assets can be significant enough to result in capacitive demand at the GSP (ie for >70% of time) when primary demand is inductive (for 100% of time).
- TSNM results are in closer approximation to the monitoring data (CLAVA data for Q demand at GSPs) compared to the empirical rule results. More specifically, after carrying out this analysis for the first 70 days in financial year 2017/18 for the same GSP, it was found that the TSNM tool and empirical rule results showed an average of four and 19MVAr difference to the monitoring data. This difference can be more significant for other GSPs due to the fact that Kearsley GSP does not involve 132 and 33kV meshings and EHV generation.

Figure 8: Half-hourly Q demand at Kearsley 132kV for a week in May 2017 (ie w/c Saturday 27 May – including bank holiday).