Accelerating Renewable Connections (ARC)

Learning Report 3

The Business Case for Top Down Investment

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Table of Contents

Table of Figures

Tables

Abbreviations

AD	Anaerobic Digester
ANM	Active Network Management
ARC	Accelerating Renewable Connections
AVC	Automatic Voltage Control
BAU	Business as Usual
BHA	Berwickshire Housing Association
CCCM	Common Connections Charging Methodology
CES	Community Energy Scotland
DCUSA	Distribution Charging and Use of System Agreement
DG	Distributed Generation
DNO	Distribution Network Operator
DSR	Demand Side Response
DUoS	Distribution Use of System
EFR	Enhanced Frequency Response
ENA	Energy Networks Association
ERF	Energy Recovery Facility
GPRS	General Packet Radio Service
GSP	Grid Supply Point
ICE	Incentive of Connections Engagement
LIFO	Last In First Off
LMS	Load Management System
MP	Measurement Point
NGET	National Grid Electricity Transmission
OCAT	Online Curtailment Assessment Tool
OLTC	On Load Tap Changer
POC	Point of Connection
PV	Photovoltaic
SO	System Operator

1. Executive Summary

1.1. Project Overview

The Accelerating Renewable Connections (ARC) project was a four-year project that commenced in 2012 and concluded in 2016. The project was successful in securing funding in Ofgem's 2012 Low Carbon Network Fund (LCNF) Tier 2 competition. Building on previous innovation projects, the ARC project has demonstrated new use cases for managed non-firm connections, informed industry around the interaction of Embedded Distributed Generation (DG) with the Transmission System Operator, empowered customers through new customer service innovations, and delivered business case information to allow any Distribution Network Operator (DNO) to adopt the same innovative techniques.

The ARC project focused on the trial area of East Lothian and the Scottish Borders. The project area is predominantly rural with a number of market towns and several large demand customers. Prior to the commencement of ARC the local network already hosted a number of large transmission and distribution connected renewable wind farm projects. The local geography includes upland areas suitable for wind development but also has some of the highest solar irradiation levels in Scotland making it attractive for photovoltaic (PV) development. The network in the area is a mix of overhead lines and underground cables serving a customer base of approximately 77,000 customers. There is approximately 300MW of renewable generation already connected in the area, although this is likely a conservative estimate due to the difficulty noted in logging domestic G83, mostly solar PV connections.

The Learning Outcomes from the ARC project are detailed in three reports:

1. Designing and Operating New Solutions Across Voltage Levels
2. The Changing Nature of the T-D Boundary
3. The Business Case for Top-down Investment in Smart Solutions

Each report has been written such that a wide range of stakeholders are able to understand and adopt (either as a user or implementer) the various innovative technical and commercial approaches trialled through the project.

This is the third report in the series and it focuses on the business case for 'top-down' investment in innovative, smart-enabling solutions demonstrated in ARC.

1.2. What is Top-Down Investment?

The concept of 'top-down' was introduced as part of ARC as a *"Demonstration of how ANM can be deployed on a larger scale using a "top-down" approach, rather than in an incremental fashion as identified in Worskstream3 of the Smart Grid Forum".*

The DECC/Ofgem Smart Grid Forum Workstream 3 Report did not explicitly define or use the words 'top-down' but it does talk about enablement versus individual solutions. Given the nature of distribution connections where minimum cost schemes are offered to each individual development.

Such an approach can often result in a piecemeal and incremental adoption model ('bottom up'). Our definition of 'top-down' is for strategic enablement investment that permits the most efficient roll-out of a range of smart solutions. The ARC project itself demonstrated a top-down approach with some of the ARC methods involving some enablement investment where the technology installed to support a single renewable generation customer can be readily extended to support the deployment of subsequent schemes.

The 'top-down' approach proposes that in the long-run, least cost and most effective approach to smart grid integration is best achieved with 'smart-enablement' of a given network area. This top-down, smart enablement allows not only generators but multiple network stakeholders to adopt and connect specific smart solutions, low carbon technologies or generation on an individual basis thereafter. The counterfactual is that, without top-down smart enablement, the sole use asset costs for distributed generation or other low carbon technologies is likely to present a barrier to future connections and incremental connection and development will not lead to the most efficient overall network solution.

In this report, we have considered top-down to involve a degree of investment in a range of advanced enabling technologies. Enabling technologies include selective deployment of network monitoring that will support a greater penetration and allow improved network modelling, integration of greater automation and control systems which will rely upon implementation of wider telecoms and operational communications infrastructure. When deployed within targeted parts of the network in response to need, the risk of stranded assets is negligible and appropriate for a 'no regrets' approach to strategic investment in support of a range of low carbon technologies. This could be considered as similar to strategic investment in primary assets but, unlike a primary asset, is more flexible and lower cost leading to an improved ability to promote 'optionality' for the network operators and their customers.

2. Drivers for Investment

This section outlines the current drivers for 'Top-down' investment in network infrastructure to develop a modern distribution network capable of supporting future stakeholder requirements, including Distribution Network Operators (DNO), Transmission Operators (TO), System Operator (SO) and all users of the system. Reference is made to the current regulatory framework that drives many of the business decisions of these stakeholders.

2.1. Energy Policy and Future Energy Scenarios

UK Energy Policy and customer choice has seen a shift in direction over the last decade. The progressive drive toward a low carbon economy coupled with environmental subsidies to advance the connection of low carbon technologies and generation, has resulted in an increased penetration of intermittent power generation now densely located throughout distribution networks. This is in contrast to the original passive network structure where central transmission connected power stations would supply power via the transmission network and down to the local distribution network. With an increasing percentage of the UK's energy supply now coming from decentralised renewable energy sources, all UK DNO's require substantial network modernisation to accommodate continued sustainable growth in future technologies such as, energy storage, electric transportation and electrification of the UK's heat network.

Changes in this energy mix have already started to impact on how the system operator, National Grid, balances and manages the system in real-time. Furthermore, the electricity commodity market is changing as a result of large volumes of decentralised power generation and flexible demand. Balancing services (cost and volume) have increased significantly due to the intermittent nature of generation, and new services are being introduced, such as Enhanced Frequency Response (EFR) as well as greater reliance on Demand Side Response (DSR), all of which are applying new pressures on traditional utility business and operational models.

National Grids' 'Future Energy Scenarios' (FES) and the 'System Operability Framework' (SOF) highlight some of the current changes being witnessed within the UK electricity system, as well as detail expected future changes in the coming decades. The publications also highlight a fundamental requirement to transition towards a 'whole system approach' that facilitates greater visibility between transmission and distribution networks.

One of the key messages of the 2016 edition of the FES was the decarbonisation of the energy system is driving significant changes in the energy supply market. A 5GW decline in fossil fuel generation by the end of 2016 will be countered by a predicted 18GW increase in storage and 23GW increase in import capacity[1] by 2040 under the 'Gone Green' scenario. In 2016, the SOF discussed the impact of embedded generation on wider system operation and noted that in order to ensure a safe and efficient network in the future, a whole system approach was required

The whole system approach creates a natural role for implementation of the Distribution System Operator (DSO) to manage energy flows within emerging complex distribution networks. Strategic investment at both distribution and transmission voltages over the next decade is inevitable but requires a holistic approach to ensure that networks are positioned to quickly adapt to ever changing customer behaviour. Traditional solutions would schedule the upgrade of a transformer or design and deliver a scheme to reinforce an area of network subject to constraint. These traditional solutions often have high costs and long delivery times. However digital technology is evolving within the energy industry and today's customer is changing from that of a consumer to a 'prosumer', whereby they both produce and consume energy behind the same metering point.

Alignment of a next generation network within a changing energy landscape requires investment in more advanced automation and control. This will require more robust communication infrastructure and more monitoring equipment. It is essential to provide network planners with the tools to better understand the changing dynamics of the system and design solutions that enable more effective utilisation of the existing network. Such visibility will in turn better inform future investment decisions. The ARC project has demonstrated the first steps of this process by installing monitoring on the network building on learning from SP Energy Networks LCNF Flexible Networks project,

[1] Maximum predictions under the Gone Green scenario

providing high fidelity data and power flow information that was not previously available to network operators. An Example of this is detailed in Figure 1 below;

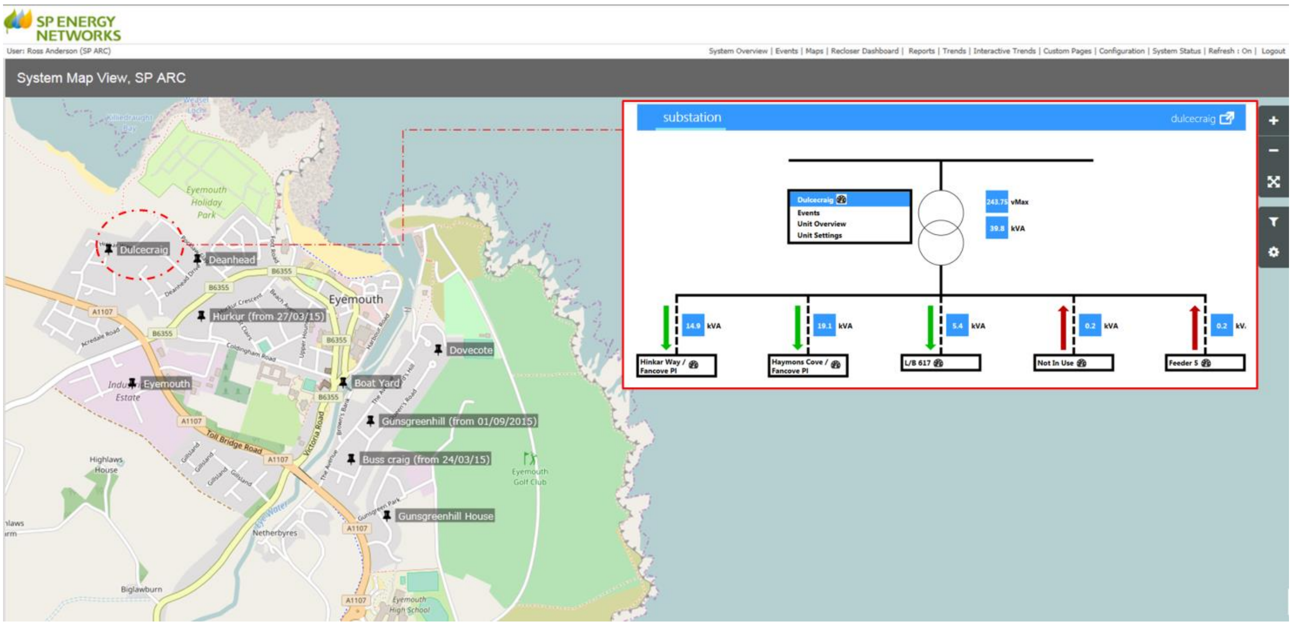


Figure 1: Dashboard Real-time Enhanced Monitoring of Local Secondary Substations

What this dashboard provides is real-time network information detailing energy flows across individual LV circuits that are fed out of a relevant secondary (HV/LV) substation. As the diagram shows, two of the five circuits monitored are exporting under the secondary substation whilst the remaining three circuits are drawing a demand. So the difficulty when designing a new connection in this area would be that this information is not available as secondary substations are not routinely monitored today. In the absence of enhanced monitoring network planners are therefore reliant upon mapping a circuit via a geographical information system (GIS) and estimating the likely load characteristics of that circuit based upon the number of customers connected along the feeder and application of a historical load profile.

Demand profiles throughout the UK are changing due to a variety of drivers, including: energy efficiency measures, uptake of new technology such as Solar PV, EV's and Heat Pumps (commonly known as Distributed Energy Resources (DER)) and changing customer behaviour.

To continue to operate a safe, reliable and efficient electricity network, network operators will need to strategically invest in enabling technologies and infrastructure. For the purposes of this report they have been categorised as follows;

1. Enhanced Monitoring and Communications Infrastructure
2. Enhanced Network Planning Tools
3. Implementation of Automation & Control Systems

To develop the capabilities referenced above will require an extension beyond traditional network boundaries with greater interoperability between distributed resources, network infrastructure and end user equipment and technologies. Distribution network operators have a key role to play in order to coordinate DER's in a manner that delivers not only benefits to customers and DER resource owners, but also in respect of wider system balancing as a range of grid assets become a greater resource to support wider system operation of the national electricity network.

2.2. Stakeholders

Figure 2 below outlines the key stakeholders discussed in this report. It focuses on their roles and the dependencies of each party on wider stakeholders. The report also seeks to define the benefits that will be realised for each stakeholder by strategic top down investment. This is based on learning acquired throughout the ARC Project and within context of a rapidly changing energy market.

DNO

- The DNO is obligated to develop and maintain a safe, reliable, efficient co-ordinated and economical system of electricty transmission
- They must run an efficient, cost effective distribution system and provide new connections to the local network.
- In parallel, DNOs must deliver agreed outputs of their regulatory settlement.
- DNOs must provide a competitive return on investment in order to attract finance and equity.

TO

- Operates the higher voltage levels of the energy system and are regulated in a very similar way to the DNOs.
- The TO similarly seeks to deliver the agreed regulatory settlement and outperform where possible.

SO

- Responsible for balancing generation and demand on the energy system in real time.
- As the volume of renewable and distributed generation has increased, this has made balancing the system more complex and therefore expensive. Lack of visibilty of generation connected at distribution voltage levels is a major contributary factor to this.
- Similar to the DNO, the SO also has shareholders who expect them to outperform the regulatory settlement through incentives, by balancing the system at a reasonable cost to the consumer.

DG Developer

- Looking for a financially viable connection that will allow a reasonable return on investment within an acceptable timeframe
- In many areas of the UK, gaining firm access to the network is unlikely without substantial investment in grid upgrades
- DG sell their generated energy via off-take arrangements (or PPAs) where a long term price can be settled for energy produced. This revenue is supplemented with subsidies and other market mechanisms – however these will be phased out and developers must now focus on reducing capex costs
- Also can be part of a business trying to match their on-site demand or managed ongoing energy costs
- Can also be a community seeking to link generation with local demand and realise benefits for whole community through schemes such as Virtual Private Wire

Figure 2: Overview of Stakeholder

2.3. Regulation

2.3.1 RIIO-ED1

The RIIO price control aims to ensure that the network operators are rewarded for achieving outputs, delivering against incentives and adopting innovation to achieve an agreed cost of capital return on investment.

RIIO-ED1, the regulatory settlement for DNOs for the period 2015-2023, was designed to encourage innovation and reward network operators against six output categories, shown in Figure 3 below. These are six of the areas which Ofgem will assess the all DNOs performance against.

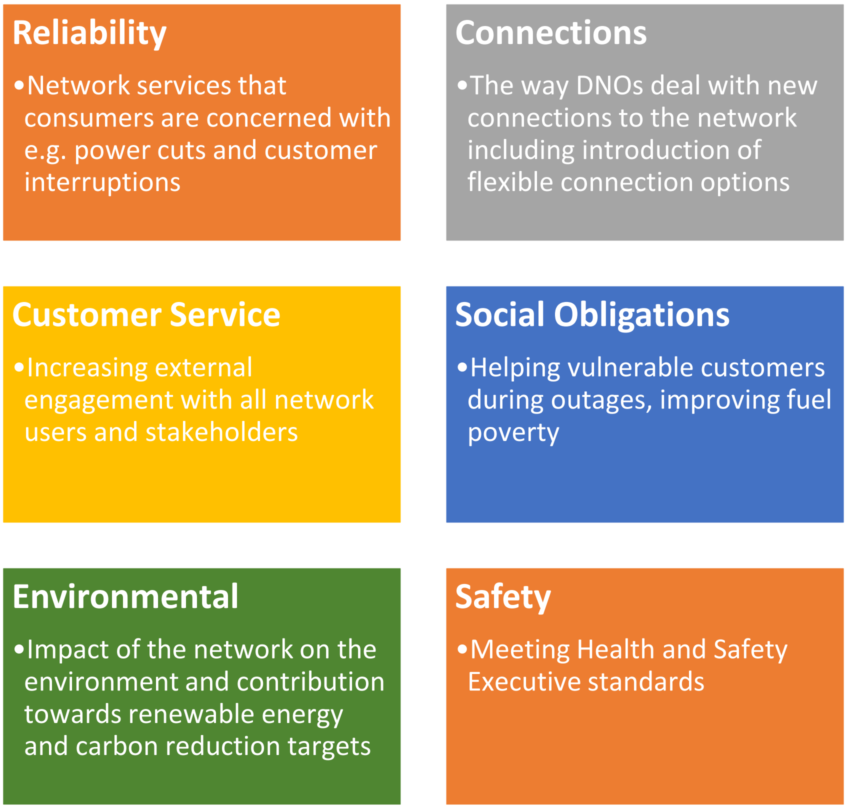


Figure 3 Performance Output Categories in RIIO

RIIO-ED1 incentivises DNO's to focus on Total Expenditure (TOTEX) – to equalise the incentives on both OPEX and CAPEX – meaning that expenditure is captured as a single allowance.

2.3.2 Pros and Con of Implementation of Smart Solutions

The benefits of smart solutions and alternatives to conventional reinforcements have been widely reported. Many innovation projects have looked at maximising the potential of existing assets as a way of deferring traditional reinforcements (e.g. Orkney RPZ, FPP, C2C and other LNCF tier two projects).

Smart solutions can facilitate the acceleration of access to the network at a potential lower initial cost (contribution toward new infrastructure or connection assets) than conventional reinforcement.

This benefit however must be balanced with the increasing resources and operational costs that implementation of such flexible connections demand. They also provide an option value, a means of evaluating the cost benefit towards triggering wider network reinforcement by the network operator. For example, the investment in a smart solution can provide a short-term mechanism for network management of connected generators, while more evidence of customer demand is built for a potential larger investment case in primary assets. The potential pros and cons of smart solutions in respect of the deferment or mitigation of up front capital expenditure per stakeholder are shown in **Table 1** and reflect the current regulatory and market conditions.

Table 1 Potential Benefits of smart solutions for different stakeholders

Stakeholder	Pros	Cons
Developer	• Reduced connection costs • Faster connection times • Potential to stack services to both National and Distribution Network operators	• Greater risk attributable to project as a result of curtailment actions being imposed by Network Operator • Increased developer costs associated with ongoing ANM O&M charges
DNO	• Contribute to delivery of 3 output metrics set in RIIO-ED1 regulatory mechanism; Connections, Customer Service and Environmental Obligations. • Ability to manage constrained networks providing connections customers with access based upon flexibility • Improved customer service by providing much faster and lower cost connections to the network	• No clear funding mechanisms in place to implement a range of enabling technologies to support delivery of flexible connection solutions • Increased requirement for operational expenditure and resources to support flexibility rollout • Smart Solutions / Flexible Connections will require increased business participation and possibly dedicated resources to design/manage such arrangements in future. • Limited market depth in proven smart solution providers • Current industry GS targets may limit the ability for DNO to implement a range of new flexible solutions • Customers connected under ANM schemes may witness increased levels of constraint if further changes 'behind the meter' erode demand.
End Consumer	• Lower electricity bills through better use of existing assets and locally produce energy.	

	• Less visual intrusion of new line construction • Less disruption from construction works	
Regulator	• Delivery of smarter networks • Reduce connection costs • Deliver against DG customer needs • Deliver against RIIO-ED1 output metrics • Maintain options for future changes in the generation and demand mix	
Government/Policy Makers	• Ensure networks are not a blocker to policy objectives or government targets • Reduce the subsidies required for DG technologies	
Transmission Operator	• Similar to DNO benefits	• Increased uptake of embedded generation makes the transmission network more complex to design and operate. Much of this is outside the control of the TO.
System Operator	• Additional capability and flexibility to operate the system • Access via DNOs to additional assets to help balance the system • Increased visibility of the overall network picture through the DNO	• Increased penetration of DG ANM schemes will likely result in a higher level of interaction between the SO and UK DNOs and will likely require additional resource and coordination between network operators.

As described above, whilst there are a number of benefits of introducing flexibility in connection solutions, this must be balanced with recognition that operating costs for network operators will increase. In order for a network operator to provide a flexible connection, the network planner is likely to require a higher degree of engagement to help understand both the proposed project objectives and the nature of the plants operation.

Learning from the project has also identified that in order to develop such flexible solutions will require the installation of enhanced monitoring, with a communications infrastructure available to collect data from a number of edge of grid devices. As well as implementation of IT systems that can host this data to be accessed and used to inform flexible network design. Such data sets would also be used by the network operator to provide end customers with greater network information to inform for example on the level of constraint that may be experienced once connected to the network.

In addition to the costs associated with the provision of a more informed network connection offers and designs, the technical solution adopted may require an increase in operation and maintenance cost or if third party technology was to be implemented, payment to vendors to cover licensing and support costs. It is therefore important to recognise that DNOs operating costs are likely to increase by delivering greater flexibility of connections across their networks.

2.4. Focus on developer connections

DNOs are under licence obligations to facilitate both demand and generation connections to their networks. The licence obligation states that the DNO must offer the minimum scheme or least cost technically feasible[2] connection option i.e. the most economic connection offer which can be delivered to facilitate the connection. This often requires the construction of additional assets and infrastructure on the network and it can be split into two types of construction work:

- ✓ Sole use assets that will only be used to the connecting customer. These are paid for in full which is typical for most distribution connections, and;
- ✓ Shared use assets, infrastructure deemed to be used by a number of system users.

[2] Reinforce only as much as is necessary to connect the customer to the network

3. Investment in Smart Grid Architectures

This section will discuss the necessary investments in network technology required to facilitate new distribution system architectures capable of delivering new flexible solutions whilst maintaining a safe, reliable and economic service to all users of the system.

3.1. Enhanced Monitoring

Maintaining a safe and reliable network requires visibility of an asset's condition and operational status and is typically captured via a network of Remote Terminal Units (RTU) at key node substations. Information is then captured and presented to an operational control room via a Supervisory Control and Data Acquisition system, known as (SCADA).

Uptake levels in renewable distributed generation throughout the last decade following the introduction of the Feed-in-Tariff (FiT), coupled with forecast in levels of adoption towards electric vehicles and heap pumps, has lead SP Energy Networks, along with all other UK DNO's to expand visibility of the distribution system to ensure continued operation of a safe, reliable and economic network.

The collection of more frequent data at a variety of nodes that communicate an asset's status and performance will enable timely visibility of grid problems in future. This is true for both real-time and long-term system planning.

Real-time monitoring must expand beyond the substation circuit breaker with deployment at key strategic nodes and all DER installations greater than 150kW.

3.1.1 ARC Case Study – Enhanced Network Visibility

Traditionally local 11kV distribution networks were only monitored at the source substation circuit breaker with a network design philosophy based around a 'fit and forget' approach i.e. network infrastructure would be designed to accommodate both minimum and maximum demand whilst maintaining an electricity supply to each connected customer within statutory voltage limits. As shown in figure 4;

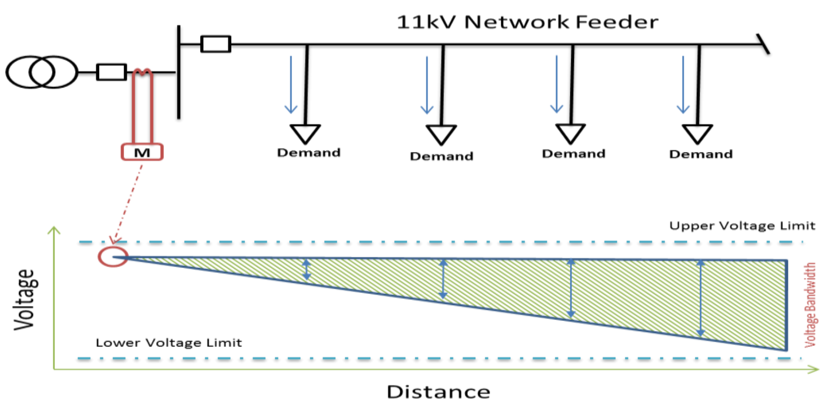


Figure 4: Assumed Voltage Drop over Distance

With growing levels of embedded generation connecting lower down the voltage levels, this traditional model of 'fit and forget' is becoming more challenging and through enhanced monitoring under ARC, see Figure 5, we can see the impact of new DER connected to the network from conventional design assumptions.

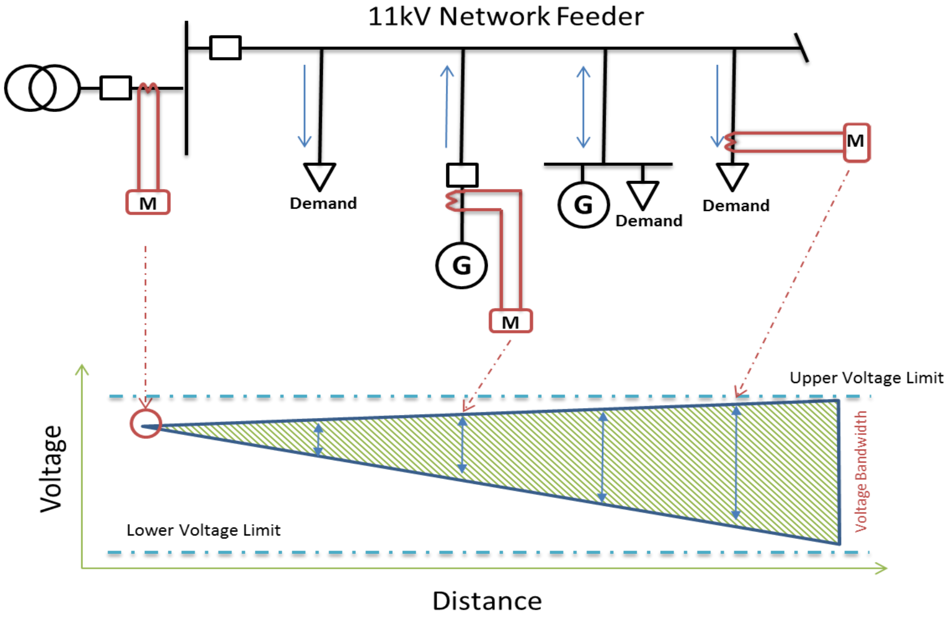


Figure 5: Typical Voltage Profile with Penetration of High Levels of DG

Many rural 11kV circuits now contain an array of embedded generation technologies, such as Wind, Solar and Combined Heat Power (CHP). Figure 6 below presents sampled data from installed network monitoring devices along a rural 15.4km 11kV OHL circuit within the ARC trial area. Analysis of the data indicates that measured network voltages at the remote end of the circuit is approximately 1% (2.4V) higher than that of the source voltage at the Primary Substation.

Enhanced network visibility provides planners and designers with more granular information when assessing a networks ability to host additional capacity.

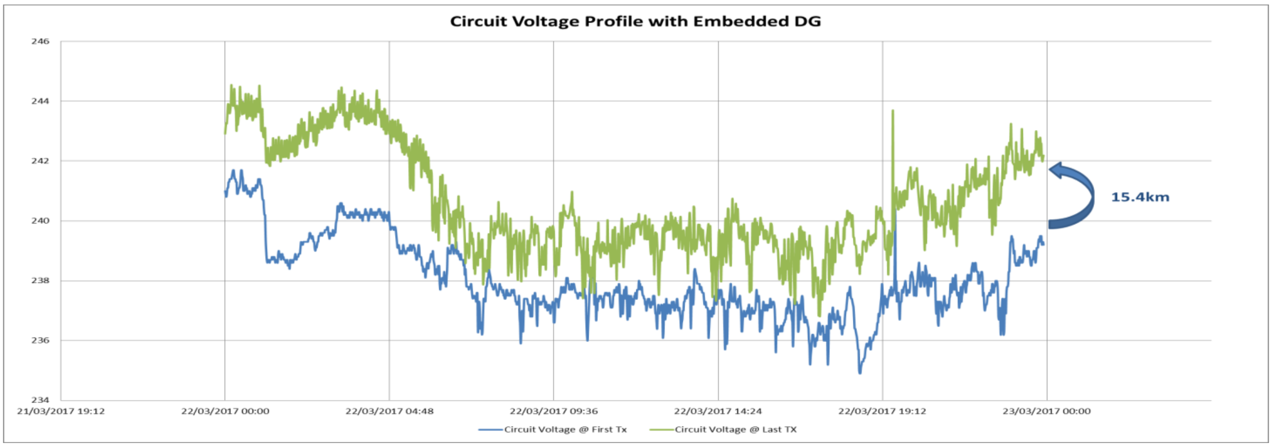


Figure 6: Measured Voltage Profile: Typical rural circuit with Embedded DG connected

3.1.2 ARC Learning - Enhanced Monitoring Capabilities

More access to data improves the ability of the DNO to operate, plan and maintain an efficient network that over time will continue to witness a proliferation in Distributed Energy Resource (DER).

To directly address these challenges, SP Energy Networks, as well as all UK DNO's require greater situation awareness of bi-directional power flows, voltage regulation, system fault level and power quality conditions. Top-down investment in enhanced network monitoring beyond the traditional substation circuit breaker is required as a minimum to meet the needs of a highly distributed future energy system.

To address these concerns, learning from the ARC project recommends that UK DNO's be given an incentive to invest in the following applications to deliver these necessary future capabilities;

3.1.2.1.1 Secondary Substation Monitoring Equipment

Installation of monitoring equipment within primary and secondary substations subject to significant penetration of Low Carbon Technology (LCT) e.g. Solar PV, Heat Pumps & EV's

Recording of data in 10 minute resolution capturing the following directional information across all three phases;

- ✓ Real Power (W)
- ✓ Reactive Power (VAr)
- ✓ Apparent Power (VA)
- ✓ Voltage (V)
- ✓ Current (A)

3.1.2.2 ARC Case Study – Secondary Substation Field Equipment Examples

The ARC project has trialled a number of network secondary substation monitoring devices in line with the identified capabilities to capture and demonstrate the benefits of data in releasing additional network capacity, as identified in Table 2.

Monitoring Device	Location of Use	Purpose	Outage Required
Lucy Electric GridKey MCU 520	Ground Mounted Secondary Substation Pole Mounted Transformer	Generation Monitoring New Connections Design Outage Planning	No
GMC-I LV METSys	Primary/Secondary Substation Monitor	New Connections Design	No

Table 2: Summary of Secondary Substation Monitors deployed under ARC

Device Type:	**MCU 520**
Functionality:	3Ø Voltage, Current, Active Power, Reactive Power, Apparent Power, Power Factor, THD, Frequency
Environment:	IP65
Dimensions:	Width: 285mm Depth: 109mm Height: 458mm
Weight:	3.25kg
Location:	Secondary Substation Pole Mounted Transformer
Installation Time:	1 Hour Per Device
Communication:	GPRS
Comments:	Generation Monitoring and Design Connections LV Design

	Outage Planning Identification of Additional Network Capacity	

Table 3: Lucy Electric LV GridKey Monitor

Device Type:	**GMC-I LV METSys**	
Functionality:	3Ø Voltage, Current, Active Power, Reactive Power, Apparent Power, Power Factor, Frequency	 
Environment:	IP55	
Dimensions:	Width: 400mm Depth: 170mm Height: 300mm	
Location:	Primary / Secondary Substation	
Installation Time:	4 Hour Per Device	
Communication:	GPRS	
Comments:	Generation Monitoring and Design Connections LV Design Outage Planning Identification of Additional Network Capacity	

Table 4: GMC-I LV METSys Monitor

3.1.2.3 Medium Voltage 3 Phase Load Monitoring Equipment

Installation of Medium Voltage load monitors on 11kV and 33kV overhead lines were installed to capture time series network loads remote from the source substation circuit breaker. The purpose of the devices was to provide both system planners and operational engineers with enhanced visibility of network conditions on sections of network identified as having significant penetration of DG.

Devices were configured to provide half hourly RMS current values for each phase conductor.

Monitoring Device	Location of Use	Purpose	Outage Required
Tollgrade MV Monitor	33/11kV Overhead Lines	Generation Monitoring New Connections Design Outage Planning	No

Table 5: Medium Voltage 3 Phase Load Monitoring Summary Table

3.1.2.4 ARC Case Study – Medium Voltage Sensor Field Equipment Examples

Device Type:	**Tollgrade MV**
Functionality:	3Ø RMS Current
Environment:	IP55
Location:	33/11 kV Over Head Line
Installation Time:	~1 Hour Per Device
Communication:	GPRS

Comments:	Generation Monitoring and Design Connections LV Design Outage Planning Identification of Additional Network Capacity	 

Table 6: Tollgrade MV Monitor

3.1.2.5 Remote Network Devices – Wireless Communication

Expansion in network visibility requires additional bandwidth and communications coverage to support increased data collection from network devices as identified is **4.1.2.2** and **4.1.2.3**. Traditionally, Distribution Network Operators only extended fibre and copper telecommunication infrastructure to key system node locations i.e. Grid and Primary Substations.

New wireless communication infrastructure will be needed to enable enhanced network monitoring and must be capable of 30 second maximum round trip latency system wide, with a 99.9% high level of reliability applicable to both rural and urban environments.

Edge of Grid Comms	**Low Priority**
Latency/data rate	sec/kbps
Example Technology	3G/GPRS
Device Example	Line Monitors/Secondary Substations

Table 7: Typical Edge of Grid Communication Requirements

Under the project data from remote monitoring devices has been collected by utilising existing mobile telecommunication infrastructure. In future, exponential increases in the volume of low priority data being gathered back to the network operator under a future smart grid must give consideration to the most appropriate means of gathering this information in future;

- ✓ Data & Cyber Security
- ✓ Rural Network Coverage
- ✓ Urban Network Coverage
- ✓ Underground Environments
- ✓ Bandwidth and Latency

3.1.2.6 Data Hosting Platform

The collection of large volumes of data from remote field devices presents a challenge over data management for network operators and the means in which it is hosted for system planners and operational engineers to access in a user friendly format. To date, data from key node locations is collected and stored within data historian systems such as PI and presented in real-time on EMS/DMS SCADA systems for control engineers.

However, future requirements for edge of grid data on network operation and performance will present a 'Big Data' question to all UK DNO's. The nature of the date will be likely considered low priority if only for planning purposes and through ARC we have undertaken work in demonstrating alternative means of displaying network data, see Figure 6.

Top down investment in enhanced monitoring by SP Energy Networks also requires investment in new data hosting and dashboard tools. Overlaying network data with Geographical Information Systems (GIS) presents the raw data in a form that is easily usable across all network departments and is likely to be essential in facilitating greater flexibility when considering alternative means of network connection.

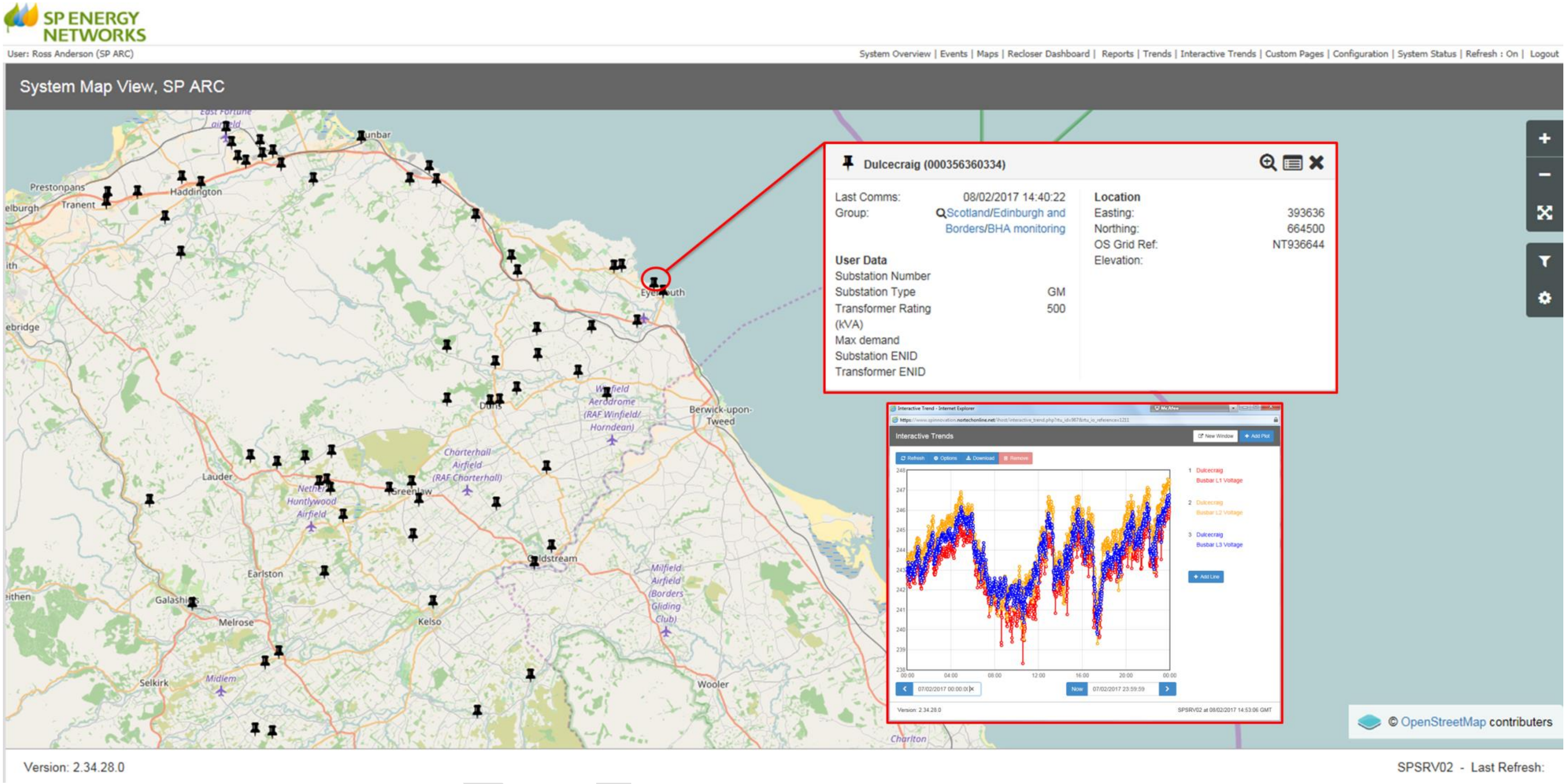


Figure 7: LV Monitoring Dashboard

3.2. Enhanced Prediction

As discussed in section 4.1, raw data is necessary in a future smart grid, however it is important that the data be cleansed, validated and interpreted for short, medium and long term system planning. Greater penetration of DER as identified in section 3.1 will require the creation of more sophisticated network planning tools to assist in understanding and assessment of decisions using the captured information.

Through ARC, it has been demonstrated that advanced network modelling techniques can be achieved with sufficient interoperability between network GIS systems, power system analysis tools and data historians.

3.2.1 GIS Network Models

During the development of OCAT, SPEN and Esri UK investigated the feasibility of transforming the geographical power network into a format that PowerFactory is able to use. The chosen format was a PowerFactory DGS file. The transformation was successful in producing a rendered fully functional PowerFactory model. This transformation is possible due to the underlying geographical structure used by Esri Technology. For example, it is possible to trace the network from a primary substation to its entire connected secondary substation network, as detailed in figure 8.

Once the network is loaded into PowerFactory, it is possible to run a number of power analysis calculations such as power flows.

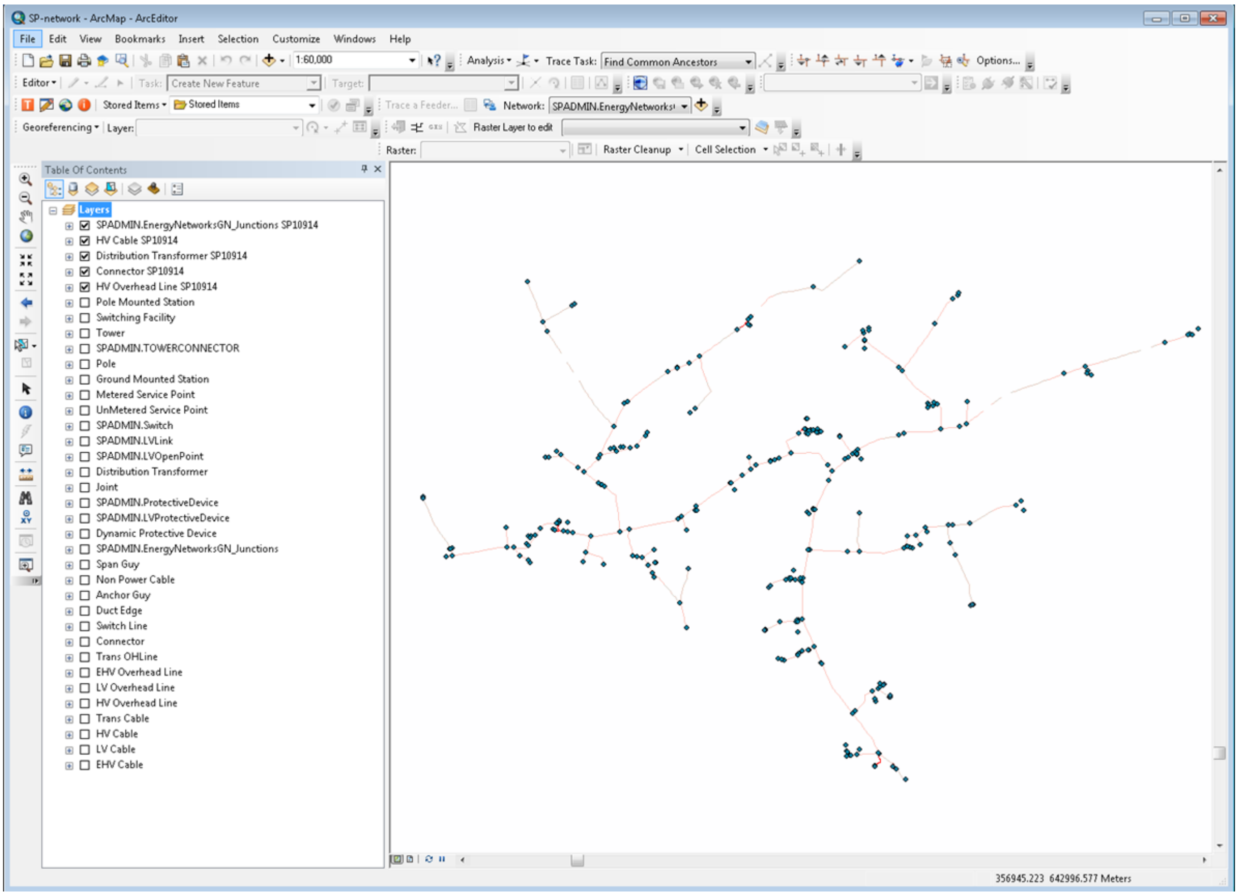


Figure 8: GIS Network Model Extract

There was however two main difficulties identified: the first one was to adapt the geometric network to the DGS requirements and the second one being the underlying data connectivity model.

To be able to transform the geometric network into a DGS file, it was necessary to remove a number of features that are required for geographical representation which PowerFactory does not understand. Furthermore, data that did not have the required information for example missing line types or voltage levels required development of new techniques to overcome these difficulties. For example, missing voltages can be deduced from connected features.

3.2.2 Power System Analysis Modelling

Once a network topology has been extracted from a GIS system, the ARC project developed the necessary techniques and tools to turn this data into a usable file capable of import into commonly used power system analysis software such as Dig Silent Power Factory.

As an alternative to DGS, a Common Interface Model XML format could have been used. The advantage of this model is that it can be imported by a number of power analysis engines "out of the box" such as IPSA, PSSE and PowerFactory.

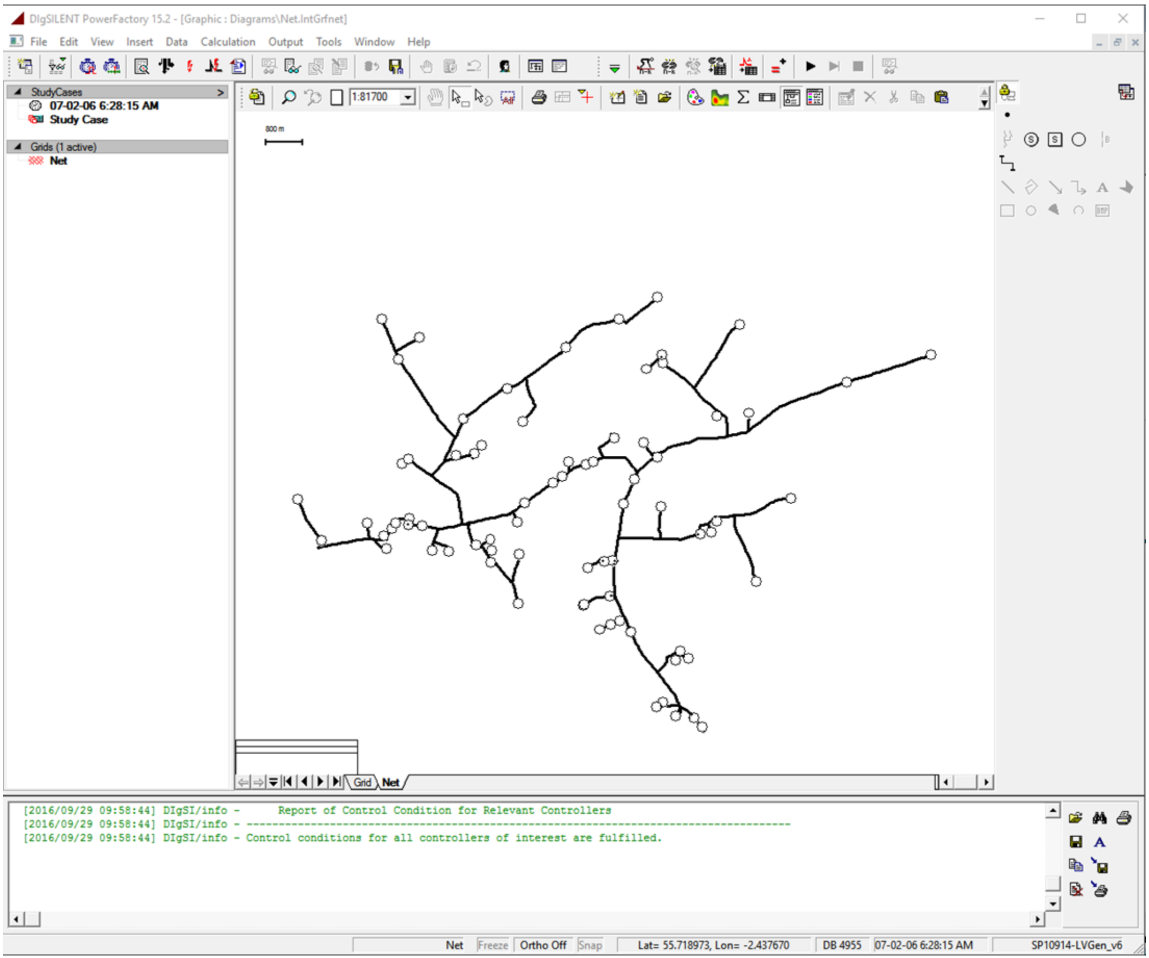


Figure 9: Power System Analysis Model extracted Direct via Network GIS

The ability to create a network model from a central GIS archive provides network design and planning engineers with a single source when undertaking network studies. As well as creating the network model in a format acceptable for use into power system analysis studies.

The ARC project has also demonstrated the ability to integrate network data from remote field monitors into the captured network model to allow the designer to perform time series analysis, demonstrated as part of the projects work around an online desktop analysis tool (OCAT).

3.2.3 Desktop Network Planning Tools

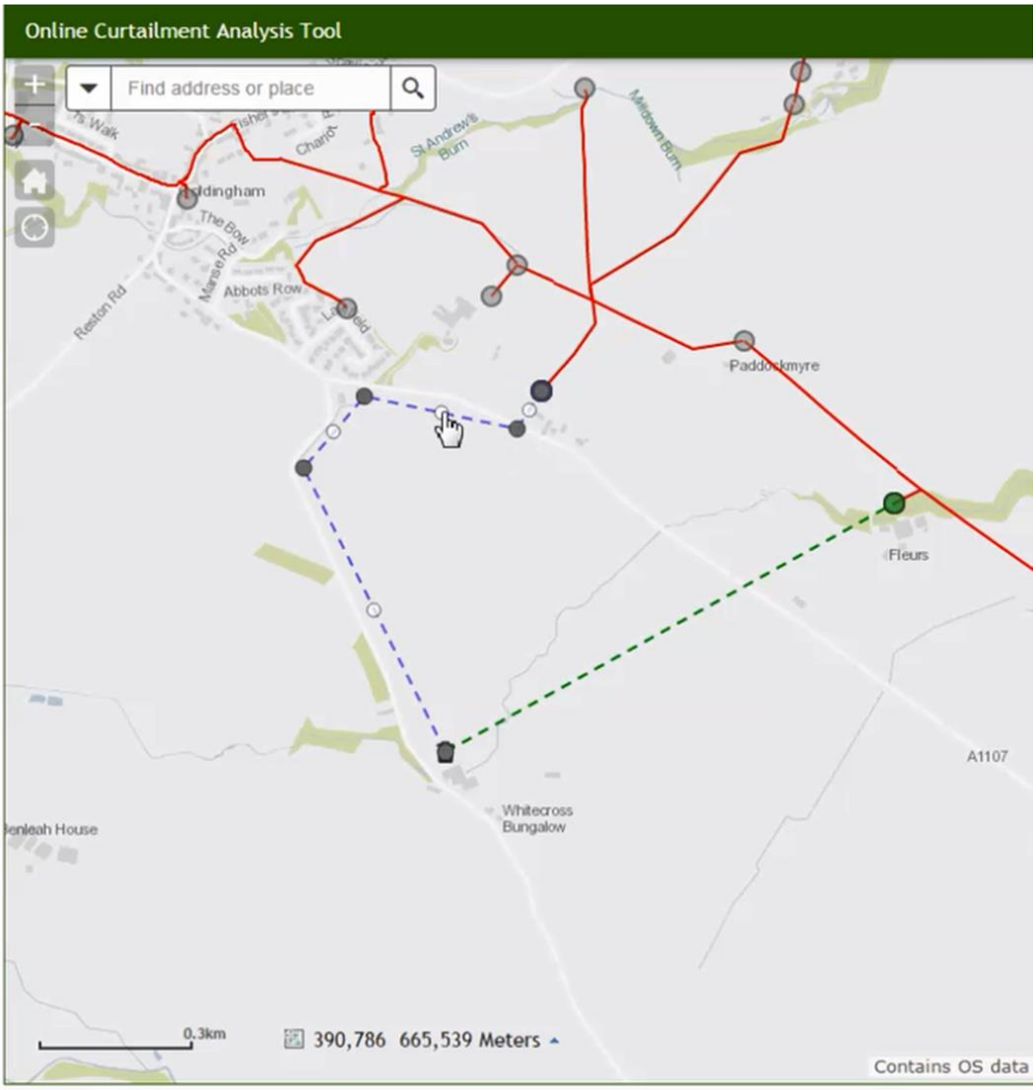


Figure 10: Desktop Network Design Tool

The demonstration of an integrated approach to network modelling has the potential to deliver significant benefits to both the DNO, but also the end customer in dealing with new connection applications. As the volume of network data increases as a result of edge of grid monitoring and wider 'behind the meter' changes in customer behaviour driven by new low carbon technology, it is important that DNO's be given the appropriate financial incentives to commit to 'top down' investments in new enhanced system design and planning tools.

3.3. Real Time Control

A future network with an abundance of DER will likely encounter scenarios that require the network operator to take proactive intervention measures at voltage levels lower than those currently managed today. Real time control and active management of the 11kV and LV network will become a necessary requirement as the system is subject to an increase in 'behind the meter' change in customer behaviour. Uptake in Low Carbon Technology such as Electric Vehicles, Domestic Energy Storage and the electrification of heat networks will likely lead to greater intermittency in customer consumption, exposing existing electricity network assets to risk of thermal overload and reduced power quality supply.

Furthermore, electricity commodity markets are evolving and fundamentally changing customer behaviour with a direct impact on the operation and design of the network.

Control of distributed assets should allow for quicker response to and isolation of hazardous conditions, hastened restoration from outages, and swift mitigation of critical violations and power quality issues. Top down investment in high speed communication infrastructure and defined operating parameters for any network connected devices will be a requirement in a modern future network.

To address these future challenges the ARC Project has demonstrated a suite of technical interventions that will help enable DNOs to manage a variety of problems caused by increased levels of DER without the need for traditional network reinforcement. Examples include;

- ✓ Voltage Violations
- ✓ Thermal Limitations

3.3.1 Medium Voltage (MV) Optimisation

MV network voltages are maintained through the use of on-load tap changers (OLTC) typically installed on 33/11kV primary transformers. These OLTCs are controlled by Automatic Voltage Control relays that, in their most basic form, maintain the 11kV busbar voltage within one tap-step (typically 1.5%) of a predefined target voltage.

Prior to the proliferation of embedded generation onto 11kV and LV networks, the AVC relay target voltage was a compromise between the statutory maximum voltage and the volt-drop that could occur at times of peak demand.

During the ARC Project, SPEN explored the use of advanced voltage control and monitoring relays that provide greater flexibility for future DER connections and day-to-day operation of the MV network. Benefits identified from the project include;

- ✓ Transformer and Individual Feeder Monitoring for Enhanced Network Data Acquisition
- ✓ SCADA Functionality for Remote Manual Operation and Reporting
- ✓ Inter-Relay Communication for Parallel Transformer Operation

3.3.1.1 ARC Case Study – Medium Voltage Control and Monitoring Relay Examples

Device Type:	**Fundamentals SuperTAPP SG Relay**
Functionality:	19" Rack Mounted Complete Voltage Control Package for Smart Grid Frequency Response 25
Environment:	IP54
Location:	Primary Substation
Installation Time:	~ 5 Days
Communication:	IEC 61850, DNP3, IEC 60870-103, IEC 60870-104
Comments:	Maximises Voltage Headroom Reduces Generator Curtailment Reduces Connection Costs for DG Accommodates Reverse Power Flow

3.3.2 LV Voltage Optimisation

It is recognised that future clustering of domestic low carbon technology 'behind the meter' will likely impact upon the day-to-day operation of the network. Consideration around voltage control under the following examples must be taken into account when investigating future investment decisions into smart grid enablers;

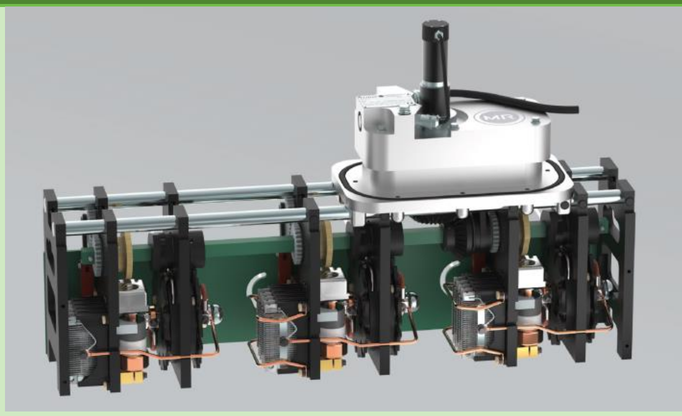
- Risk of System Overvoltage during periods of low demand combined with high generation output from domestic roof mounted PV
- Risk of System Undervoltage during periods of high demand due to penetration of LCT such as EV's and Heat Pumps

Historically secondary transformers installed throughput the UK operate with no automatic voltage control functionality. Any requirement to adjustment tapping ratios to minimise against risk of voltage excursion has to be taken off-line and managed locally.

As part of the ARC project the use of modern secondary substation transformers with on-load tap changers (OLTC) and AVC units has been considered to demonstrate innovative techniques in addressing future local voltage control problems caused as a result of 'behind the meter' changes.

3.3.2.1 ARC Case Study – Distribution OLTC Solar PV Example

Device Type:	**MR Reinhausen OLTC ECOTAP VPD & Motor Drive Unit**
Functionality:	Maximum Voltage Upto 36kV Maximum Voltage Step Upto 825V Maximum Transformer Rating Upto 8MVA 500,000 tap-change operations without maintenance 9 Tap Positions 20 Tap-change Operations per Minute
Environment:	IP54
Location:	Secondary Substation
Communication:	DNP3, Modbus, IEC 61850, IEC 60870-104
Comments:	Maximises Voltage Headroom Voltage Optimisation for Future LCT Uptake Available for retro-fit to existing transformers.



3.3.3 Thermal Management

SP Energy Networks has witnessed a steady uptake in distributed generation over the last 10 years with majority of customers connected where thermal constraints are designed out at the planning stage. Network design and planning standards developed the network in such a manner that no thermal overload conditions would occur during both intact and N-1 conditions, N-1 conditions typically being periods of network maintenance or system faults. Significant growth in intermittent embedded generation within the distribution system has resulted in thermal constraints beginning to appear during initial design and planning stages. Resulting in high costs for connection, long delays to connect and triggering of wider network reinforcement works.

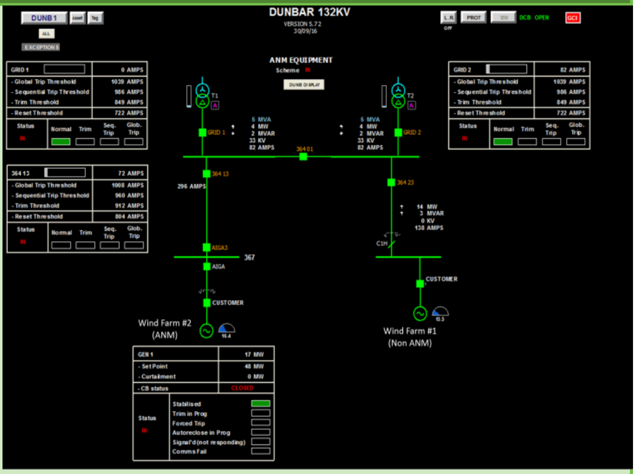
It has been demonstrated under ARC that active thermal management of system thermal constraints can be achieved through the use of Active Network Management (ANM) technology, whereby the DNO measures a predefined constraint location and in the event of any system overload, instructs in real-time any contributing embedded generation to curtail to a level set by the ANM scheme in a priority order, known as Last In Frist Off (LIFO).

Learning from the project has demonstrated that transition from a traditional passive network to a network which is more active in its management of network constraints will require significant top down investment in distribution network infrastructure. Such a transition places additional duties upon network operators not only to maintain and respond to network faults as reported through an operational control centre DMS, but to ensure control schemes which take autonomous controlling actions over customers assets are maintained and resourced to ensure minimum customer interruptions are experienced.

The roll-out of thermal management schemes such as ANM across the business will require top down investments by the DNO. Investments include;

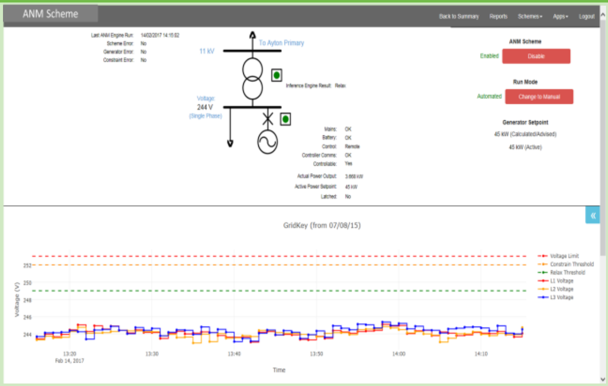
- Resource from DNO's to design, implement and maintain Active Network Management Schemes across the business.
- Development of skills necessary to operate real-time control systems.
- A network of enhanced communications infrastructure beyond traditional SCADA.
- Enhanced data management for auditability of ANM system performance.
- Data hosting within the operational control room environment.

3.3.3.1 ARC Case Study – Wide Area Active Network Management

Device Type:	**Smarter Grid Solutions – Core & Comms Hub ANM Platform**	
Functionality:	Multi Generator, Multi Constraint ANM System Autonomous Real Time Control	
Environment:	IP20	
Location:	Centralised (Control Centre) or Decentralised (Substation)	
Communication:	DNP3, Modbus, IEC 61850, IEC 60870-104	
Comments:	Maximises Network Generator Hosting Capacity Provides Real Time Control for System Operation	

3.3.3.2 ARC Case Study – Local Active Network Management

Device Type:	**Nortech iHost ANM Platform**
Functionality:	LV Generator Constraint Management Single Generator, Single Constraint Scheme Low Cost Solution
Environment:	IP65
Location:	Customer Substation
Communication:	DNP3, Modbus, Over GPRS
Comments:	Maximises Network Generator Hosting Capacity Provides Real Time Control for System Operation



4. Investment Requirements

The following section describes the Investment Options trialled during, or informed by, the ARC project. It is hoped that some of these examples will inform future investment decisions by defining the benefits of smart technology solutions over traditional network reinforcement.

4.1. Investment Requirement 1: Enhanced Network Monitoring

In each of the new connections delivered under the ARC Project, the final connection design solution required additional network monitoring before a viable scheme could be presented to the customer.

Monitoring of the network beyond the traditional substation circuit breaker was undertaken on a case-by-case basis with locations determined by requirements of the individual connection application i.e. circuit ID, monitor type & location. Monitoring was performed over a 12 month period where feasible to capture network behaviour and resulted in a viable solution to connect being developed for each project.

The delivery of improved customer service and increased efficiency in network design in future requires strategic investment in remote field monitoring across the network.

Benefits of enhanced monitoring is also discussed in SPEN's Tier 2 Low Carbon Network (LCN) Funded project, "Flexible Networks for a Low Carbon Future"

https://www.spenergynetworks.co.uk/userfiles/file/CostBenefitAnalysis_EnhancedNetworkMonitoring03.pdf

This project investigated several "Smart Grid" solutions to increase network capacity for load growth in place of conventional reinforcement. Detailed network monitoring of the 11kV and LV network is seen as a key enabling technology in releasing additional capacity.

The UK Government and Ofgem have already identified the GB Smart Meter programme as a means of delivering benefits to DNOs, along with benefits to consumers and other stakeholders. These benefits accrue to DNOs from the opportunity to monitor voltages and capture aggregated consumer loads as reported by smart meters. It is important that DNOs are able to capture similar information at a local substation level as customer behaviour changes in future with the uptake in Low Carbon 'Behind the Meter' Technology, as identified in section 3 of this report.

4.1.1 Investment Example: Bassendean Farm AD Plant - Value of Enhanced Network Monitoring

The owner of Bassendean Farm based in the Scottish Borders, approached SP Energy Networks requesting an upgraded network connection to facilitate a new 150kW AD plant as part of the farms move towards a more sustainable business model. Initial analysis of the local network using data available from the source primary substation circuit breaker identified the requirement to construct a new 2.9km 11kV overhead line to facilitate the connection.

The construction of a new 2.9km overhead line resulted in a cost to the customer of £225,000.

Deployment of strategic network monitoring remote from the source circuit breaker provided system planners with enhanced network visibility along the entirety of the 15km circuit and adjacent circuits fed from the source primary substation. Enhanced data and visibility resulted in the decision to lower network voltages within the area to accommodate the generator without the need for a new 2.9km over head line.

The data gathered from key circuit locations is identified in table 6 below;

Substation/Location	Monitor Type	Distance to Source Tx	Maximum Recorded Voltage (Pre*/Post** Voltage Reduction)	Minimum Recorded Voltage (Pre*/Post** Voltage Reduction)
Gordon Primary Substation	(GMC-I LV METSys)	Source	11.14/10.98kV	10.765/10.57kV
Bassendean PTE	GridKey MCU 520	3.5km	251.5/248.75V	239/237.74V
Westruther	Tollgrade MV Current Sensor	6.7km	- *Max Cct load 23amps/0.5MVA **Max Cct load 25amps/0.45MVA	- *Min Cct load 3 Amps/0.06MVA **Min Cct load 2 Amps/0.05MVA
Snawdon	GridKey MCU 520	15.5km	251/248.25V	238.5/235V
Hume Hall	GridKey MCU 520	6.8km	250.5/246V	237.75/231V

Table 8: Results of Enhanced Network Monitoring

The methodology used was to monitor the nearest Point of Connection (POC) capable of accommodating the generator on a thermal basis, capturing network 3 phase load and voltage profiles over a 12 month period. Monitoring also captured network data from the circuit's mid-point (~6.7km) and the remote end-point of the circuit (~15.5km). As shown in Figure 12;

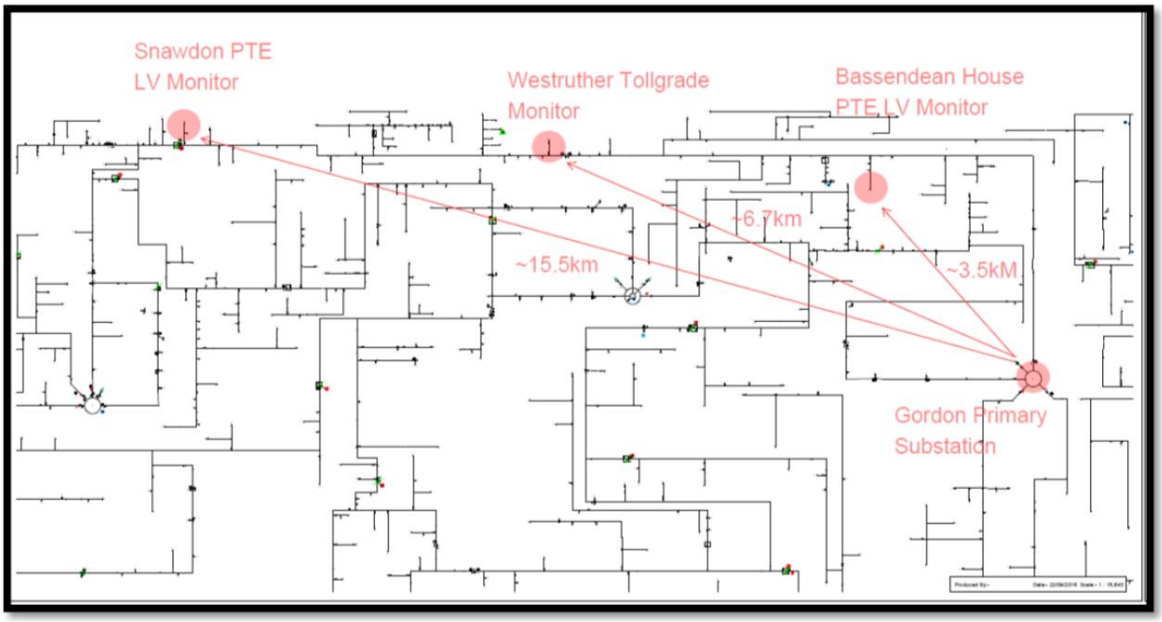


Figure 11: Enhanced Network Monitoring Locations – Bassendean Cct

To ensure that no customers would be adversely affected by the voltage reduction, monitoring was also installed on adjacent circuits fed from the source primary substation to capture the effects that a voltage reduction would have on end points of the all primary substation feeders, example as shown in figure 13;

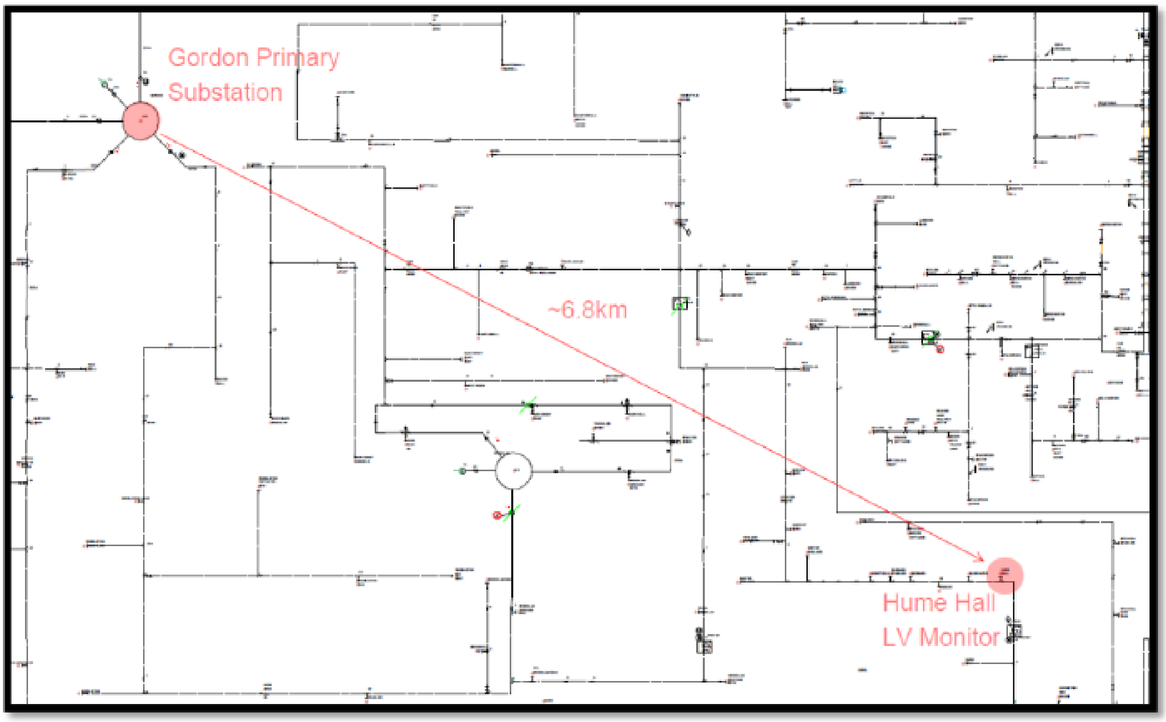


Figure 12: Enhanced Network Monitoring Locations – Alternative Cct

The benefits associated with deployment of enhanced network monitoring directly resulted in a reduced connection cost to the customer, as detailed in table 7;

Table 9: Financial Benefits Associated with Enhanced Monitoring

	Direct Customer Costs	Additional Support Costs	Scope of Works
Traditional Solution	£225,000	2.9km OPEX	2.9km 11kV OHL, New 200kVA PTE, LV Mains
Enhanced Connection Option with Enhanced Monitoring	£25,000	Monitoring	New 200kVA PTE, LV Mains

4.2. Investment Requirement 2: Edge of Grid Communication Infrastructure

With an increased level of edge of grid infrastructure deployed as components to a future 'smart grid', examples include; Network Monitoring Devices, Intelligent Network Controllable Points (NCPs), Voltage Regulators and D-Statcoms - will ultimately require a network of integrated network communication to capture and control an array of network devices.

Increased visibility in connected DER will also be required for short, medium and long term system planning and day-to-day operation. Resource includes renewable sources such as Wind and Solar PV, intermittent demands such as Electric Vehicles and Heat Pumps and flexible assets in the form of energy storage.

Historically network operators only required limited visibility of edge of grid infrastructure. Traditional devices are effectively stand-alone, designed to protect a circuit without any requirement for communicating status to remote systems.

Increasing requirements being placed on DNO's to facilitate more and more DER lower down the system voltage levels has resulted in a number of innovation projects being undertaken to explore learning around future power system architectures and what this means for DNOs and any future investment decisions.

4.3. Investment Requirement 3: Enhanced Data Hosting and Modelling Techniques

In common with a number of other LCNF/NIC/NIA projects, the widespread introduction of low carbon technologies on DNO networks, particularly on 11kV & LV feeders, is an emerging challenge for network planners. For example, there are over 90,000 LV feeders in GB, and none are routinely monitored or modelled. This has previously proved to be adequate due to the relative ease of predicting LV customer demands in a network based around traditional power system architectures. However, as this approach becomes increasingly challenged by the low carbon transition, DNOs require investment in more advanced data hosting and modelling techniques to ensure provision of a safe, reliable and secure network.

Typical LV feeder loadings comprised mainly of domestic customers with profiles established from years of research. Using after Diversity Maximum Demand (ADMD) enables network planners to establish maximum loadings and maximum voltage drop for demand only. Over the past 40 years it is widely accepted within the industry that typical ADMDs for domestic mains-gas heated dwellings has reduced from about 2.5kW to an estimated 1.7kW. Changes in customer load are mainly as a result of improved energy efficiency measures within domestic appliances, a switch from incandescent lighting to alternatives such as LED, and the uptake in domestic solar PV as a result of the UK Governments Feed-in-Tariff scheme.

4.4. Investment Requirement 4: MV Voltage Optimisation

Where the introduction of an embedded generator involves a voltage constraint on the High Voltage network, it may be possible to resolve the constraint by improving the MV voltage operating performance.

MV network voltages are maintained through the use of on-load tap changers (OLTC) installed on the 33/11kV primary transformers. These OLTCs are controlled by Automatic Voltage Control relays that, in their most basic form, maintain the 11kV busbar voltage within one tap-step (typically 1.5%) of a predefined target voltage.

Prior to the penetration of embedded generation in MV and LV networks, the AVC relay target voltage was a compromise between the statutory maximum voltage and the volt-drop that will occur at times of peak demand. Traditional design methodologies set a target MV busbar voltage around 11,200V (1.02 p.u) to account for voltage drop along the feeder due to circuit demand.

Historically, network planning for any embedded generator takes the worst-case circuit condition into account so that the voltage rise ‘headroom’ is restricted to the gap between the target busbar voltage and the higher statutory limit. However, given the intermittent nature of embedded generation it is possible that for periods this design principle unduly restricts the opportunity to accommodate additional renewable generation onto the network.

In order to ensure that the MV busbar voltages are maintained as close as practicable to the target voltage, it proved necessary under the ARC project to replace the existing AVC relays with modern alternatives. The replacement AVC relays can also adjust the busbar voltage to reflect voltage variations due to any generation which is directly connected to the MV busbar. By optimising for circulating current the AVC relays can also accommodate paralleling of transformers which have dissimilar characteristics and where the transformers are connected via MV feeders.

As an alternative to traditional network reinforcement, investment (prior to natural asset life replacement) in modern AVC relays could be made to effect an adjustment of MV busbar voltage more quickly and at much reduced capital expenditure.

4.5. Investment Requirement 5: LV Voltage Optimisation

Projected uptake in domestic 'behind the meter' changes across the energy sector, including Heat, Transport and Electricity requires alternative means of addressing future intermittency problems at a local LV substation level. The current approach to load growth is to trigger enhanced network monitoring at locations identified as having high levels of Low Carbon Technologies (LCT). In the event that a voltage excursion is identified, reinforcement of the network to mitigate the problem would be triggered, however this approach may prove to be uneconomic when considered against the volume of network assets subject to potential constraint in future as a result of continued adoption of LCT.

One technique demonstrated under ARC to minimise the networks exposure to these future risks would be the installation of modern secondary substations with online voltage regulation functionality. With intermittency on the LV network set to increase with greater penetration levels of low carbon technology, network operators must invest in assets capable of greater flexibility. Active voltage regulation of the LV network to avoid both under and over voltage conditions could become a preferred methodology in addressing localised network issues as witnessed in the below example.

4.5.1 Investment Example: BHA PV Case Study

In October 2014, with the aim of reducing consumer energy bills, Berwickshire Housing Association (BHA) formed a partnership with Oakapple Renewable Energy and Edison Energy to investigate the installation of a solar scheme with 749 roof-mounted solar PV systems. Each PV installation ranged from 2 kW to 4 kW, with a total proposed installation capacity of around 2,600 kW. The proposed PV systems were to be installed on terraced and semi-detached properties located across Berwickshire, including Duns, Eyemouth and Coldstream. This covered 59 secondary substations under the Berwick, Dunbar and Eccles GSPs. Proposed connections were heavily clustered around Eyemouth primary substation. The proposed installations represented multiple new connections onto an already constrained network area. The connection was subject to G83/2 Stage 2 analysis whereby a study of network impact was required in order to ensure that the distribution network will continue to operate within design limits.

Following detailed network analysis, combined with enhanced network monitoring of substations identified as having high levels of PV clustering. A number of secondary substations were identified as requiring intervention to ensure network voltage limits were maintained within statuary limits throughout the year. The solution trialled was the installation of new OLTC secondary substations whereby LV network voltages are automatically regulated throughout the year to cater for Low Demand, High Generation Periods in Summer and High Demand, Low Generation periods in Winter.

4.6. Investment Requirement 6: Active Network Management

The low carbon transition currently underway within the UK is changing the fundamental power system architecture of the network. Flexibility can only be realised if distribution networks evolve to operate with higher levels of active control above current levels.

Through ARC, it has been demonstrated that using methodologies such as Active Network Management (ANM), can have significant benefit to all parties within the energy system moving forward, see table 8;

4.6.1 Investment Example: Dunbar GSP ANM Scheme

Stakeholder		Benefits of Active Management
Developer	✓	Early Network Access prior to completion of Network Reinforcement Works
Distribution Network Owner (DNO)	✓	Enhanced visibility and real time control over embedded distributed assets
Transmission Owner (TO)	✓	Enhanced mechanism to manage embedded generation during periods of transmission network outages
System Operator (SO)	✓	Enhanced mechanism to access greater flexibility services from distribution connected assets.

Table 10: Dunbar GSP ANM Scheme

Transitioning away from a historically passive network to one which is more dynamic and active in its operation requires significant investment in operational systems and resource capable of supporting such schemes on an enduring basis. Learning from ARC is that short term benefits can be clearly identified for those developments connecting earlier than traditional arrangements, however wider benefits to all other parties, as identified in Table 8, can only be realised if a Top-down investment approach is taken across the industry whereby network operators commit significant investment programmes into such systems in calibration with each other.

5. Top-Down Investment Mechanisms:

This section will discuss potential Top-down investment regulatory mechanisms that could be made available to network operators and provide the ability to invest in those enabling technologies discussed throughout this report.

This investment will not be realised by a piecemeal drip-fed approach. UK DNOs require a clear funding mechanism that allows them to respond to the needs of the customers and communities that they serve and invest in enabling technologies. Only this will allow greater flexibility such as deployment of Active Network Management schemes as Business As Usual and accelerate the transition to Distribution System Operators.

In considering what new funding mechanisms could be deployed to accelerate adoption into Business as Usual, we have reviewed previous policy and regulatory mechanisms implemented that could be revised and developed in a similar way to enable network operators to lay the foundations for smart grid transition and which are detailed below.

5.1. Distributed Generation Incentive Mechanism (DGIM)

During Distribution Price Control 4 (DPCR4) Ofgem introduced the DGIM funding mechanism in recognition of the expected increase in distributed generation that would connect during that period. The purpose of the DGIM was to encourage DNOs to undertake the investment required to facilitate future DG connections and encourage DNOs to invest efficiently and economically.

The DG incentive was calculated to provide DNOs with an additional rate of return above the agreed allowed cost of capital agreed with network operators at that time. The value of the incentive was based upon a £/kW calculation of forecast reinforcement costs to connect distributed generation which resulted in an incentive rate of around £1/kW/year.

The broad characteristics of the DG incentive framework were that:

- ✓ Capital costs incurred by DNOs to provide network access to DG were given a partial pass-through treatment, and
- ✓ The DNOs were then given a further supplementary £/kW revenue driver to incentivise efficient connection of DG to the network.

The table below provides further information on the key elements of the DG incentive framework that was implemented for both DPCR 4 and DPCR 5.

Framework Element	DPCR 4	DPCR5
Pass-through capital costs	80 per cent (annuitized over 15 years)	80 per cent (annuitized over 15 years)
DG Incentive value	£1.50/kW/yr for 15 years (£2.00/kW/yr applicable to SSE)	£1.00/kW/yr for 15 years
Cap & Collar on Return	Cap: two times WACC Collar: assumed cost of debt	Cap: two times WACC Collar: assumed cost of debt
Operational & Maintenance Allowance	£1.00/kW/yr	£1.00/kW/yr
'High Cost' Projects	Direct reinforcement costs in excess of £200/kW	Direct reinforcement costs in excess of £200/kW

Table 11: DG Incentive Framework

5.1.1 Pass-Through and Incentive

The hybrid incentive framework combined incentives for efficiency with protection against cost uncertainty via a partial pass-through mechanism. The pass-through rate of 80 per cent (annuitized over 15 year) was considered appropriate at that time. In addition, the DG incentive rate was based upon use of system connection assets costs only. The incentive rate remained in place for a period of 15 years following the connection date of the connection asset.

5.1.2 Cap and Collar on DNO Returns

The incentive mechanism also developed principles for setting a cap and collar on DNO returns from investment via the DGIM, which was designed to protect both the DNO and end consumers against cost uncertainty. This meant that the collar on the rate of return on use of system connection assets incurred to connect DG in DPCR5 would be no less than the assumed cost of debt (3.6 per cent pre-tax) and the cap would be restricted to not more than two times the pre-tax Weighted Average Cost of Capital (WACC) (11.2 per cent).

If no costs were incurred during the price control period, associated with use of system connection assets required to connect DG, a DNOs income would be capped at £0 for DG connected over the price control period. Therefore if no use of system assets were required no revenue would be received.

5.1.3 Operation and Maintenance (O&M) Costs

As part of the DGIM, there was a provision that permitted the DNO to charge an O&M allowance at £1/kW/yr to cover ongoing O&M costs of those DG connection assets installed and funded through the DGIM.

5.1.4 Recovery Mechanism

Initially the total revenue that a DNO could recover from investment under the DGIM scheme was recovered from only those generators that connected to the system during the initial DPCR 4 price control period. However during DPCR 5 Ofgem removed this restriction so that the total revenue that a DNO could recover under the DGIM could be combined with the allowed demand revenue to create a single charging pot. This combined allowed revenue pot was then able to be allocated amongst the different categories of customers using the new charging methodologies.

5.2. Registered Power Zones (RPZs)

In November 2004 the final DPCR 4 proposals were published that included the introduction of a new incentive mechanism relating to Registered Power Zones (RPZs). RPZs focussed specifically upon the connection of generation to the distribution network and were designed to encourage DNOs to develop and demonstrate new, more cost effective ways of connecting and operating generation that would deliver specific benefits to new distributed generators and broader benefits to consumers generally. As part of the incentive mechanism, Ofgem proposed an additional revenue incentive of £3/kW/year (over and above the main DG incentive) for a five year period commencing on the connection date of the relevant project.

As part of the governance arrangements, whilst Ofgem would register the projects, they did not approve new RPZs but rather relied upon advice from independent experts who would review and report on innovative content and potential benefits of an RPZ proposal. Ultimately the DNO would take full responsibility for the management of risks associated with development of the scheme. At that time however it was expected that the DNO would offer the connecting generator commercial terms that reflected those risks involved. RPZs were restricted however to two per DNO and formed part of the Innovation Funding Incentive (IFI) mechanism.

Whilst the RPZ made provision for additional revenue, this was capped at £0.5 million per DNO per year. The costs of RPZ projects would be met by those generators within a DNO area in the same way as the DG incentive mechanism operated.

The governance around the introduction of RPZs also took cognisance of existing generation and ability to improve export ability for those generators already connected, considered staged development and commissioning of activity associated with the RPZ. Ofgem also recognised that whilst a DNO had a license obligation to make a connection offer in three months, those timescales may constrain the development of an RPZ in some situations and highlighted that following a request to Ofgem; the Authority could consent to a longer connection offer period.

5.3. Summary/Conclusions

Both these regulatory innovative incentive mechanisms provide positive examples of how network operators could fund and transition to longer term deployment of Smart Grid enabling technologies. They made provision for cost recovery and ongoing operational and maintenance costs over the projected life cycle of network assets and provided a mechanism for those costs to be recovered across a range of network customers that was fair, equitable and transparent.

More recent funding mechanisms such as the Low Carbon Networks Fund and Network Innovation Competition have been successful in creating stimulus across network operators to trial and implement new innovative technology and novel operational practices. Whilst a positive step change this needs to be balanced with development of a funding and cost recovery mechanism that permits the wider deployment beyond trials into Business As Usual application.

The reintroduction of a funding mechanism available to DNOs that draws upon the fundamental principles and objectives of the DGIM and RPZ frameworks would represent a significant step forward in realising the investment required to implement smarter networks. Furthermore this holistic Top-Down investment approach would in the long term represent greater efficiency cost benefits for all systems users.

6. Conclusions, Learnings and Recommendations

6.1. Conclusion/Summary of Learning

The ARC project has trialled and demonstrated the benefits of connecting intermittent distributed generation via flexible non-firm connection arrangements. In some instances, these flexible connections can be followed by traditional reinforcement, with a positive business case. In each of the solutions trialled, we have confirmed a positive business case for alternative architecture over the traditional business as usual solution. There is a positive benefit for both DNOs, TO, SO and customers from the earlier connection of generation.

Ofgem requires DNOs to continue to improve their connection offering through the Incentive on Connections Engagement and these requirements include encouragement to reduce the time to connect new customers, including renewable generators.

As a consequence of acceleration in the connection process, any monitoring or modelling of network conditions can often occupy the project's critical path. The ARC architectures can be further accelerated through the selective deployment of network monitoring and network modelling in advance of any connection application. When applied, these enabling technologies can avoid the 12-18 months delay caused by the need to enact monitoring or modelling involving either site installation or model building.

In addition to facilitating flexible connections, future ANM architectures will support further developments of the DNO towards a DSO role. ANM does not only control and manage generation, but provides high fidelity data which gives greater visibility to the operator and thus can be used to develop markets and services at distribution level.

In the case of LV-connected solar PV generation under G83/2, there is a risk that some of these applications will be made under G83/1 so that any delay to installation can be avoided. The ARC network modelling activity found that over 60% of LV-connected solar PV was not correctly recorded. If this continues there is a risk of licence breach for DNOs and a reduction of revenue for generator owners when voltages exceed the statutory maximum limit.

6.2. Recommendations

- Ensure that the solutions trialled under ARC are integrated with SPEN connections business practices in order to ensure these architectures can be offered when and where appropriate.
- Improve SPEN's customer service offering
- Use a triage approach to LV
- There is a clear case to invest ahead of need in areas of likely high concentration of renewables in monitoring, communications and control infrastructure. All of the architectures helped accelerate connections but could have been faster had advanced enabling works been installed.
- Installation of ANM solutions as a means of not only controlling generation, but of gaining greater visibility of actions on the network at a higher level of detail than previous available through SCADA or similar systems.