New Thames Valley Vision

Learning Outcome Report

Integration Solution Control Evaluation

Scottish and Southern Electricity Networks (SSEN) is the new trading name of Scottish and Southern Energy Power Distribution (SSEPD), the parent company of Southern Electricity Power Distribution (SEPD), Scottish Hydro Electricity Power Distribution (SHEPD) and Scottish Hydro Electricity Transmission. SEPD remains the contracted delivery body for this LCNF Project.

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1. Summary

Criteria 9.8(a) Part 1

Successful Delivery Reward Criteria 9.8 (a)

Criterion:

Prepare final reports on the trials carried out on the subjects listed in "Evidence 9.8" as well as an end of project report.

Evidence:

(7) Integration Solution Control Evaluation

(Methods 1, 2 and 4, Learning Outcome 1.1.3)

- Data availability (preparation of data, works required, indirect costs)
- Functionality (assess against business and functional requirements)
- Integration (communications, interfaces with other systems)
- Scalability (consequences of applying to a larger network)

SSEPD confirms that this criterion has been met.

This document provides details of the evaluation of the integration of the Distribution Management System (DMS) and the Network Modelling Environment (NME) and presents the findings identified in line with the evidence criteria specified for the Successful Delivery Reward Criteria (SDRC). The report also defines how the system has been performing against the pre-defined requirements for LV network management.

It is confirmed that:

- The requirements to integrate the existing Distribution Network Operator (DNO) systems and data artefacts to create an integrated DSI are defined.
- The functionality of the system integration using the project specific requirements and incorporation into existing business processes has been documented.
- The technical integration of systems and communications network interfaces are described
- The time and cost of scaling the integration of the systems to the wider Southern Electric Power Distribution licence areas have been analysed and reported.

1.1. Background

The New Thames Valley Vision (NTVV) project has delivered new systems for managing the Low Voltage (LV) network. The new systems comprised an integrated Geographical Information System (GIS) with an integrated power flow analysis system to run network studies on the uptake of Low Carbon Technologies (LCT's) and to deliver an integrated planning tool for new customer connections. The NME was also integrated into an upgraded DMS to manage and control the LV network, to manage new technologies and to investigate whether novel technologies can be used as an alternative to traditional LV network reinforcement. The upgraded DMS has been setup and configured to be a subscriber service to import the LV network from the NME using standard protocols.

The report also defines the preconditions needed to create integrated GIS and LV DMS including the data preparation and transformation from the DMS perspective. The cost to extract, transform and load the data required into each system is defined. The knowledge gained and the process to prepare the source data for the LV network import has been described in full in **SDRC 9.8a (8)** – Overall Proven Benefits. The report also evaluates the replicability and scalability of the DMS set up for the project.

A full review of how the systems are performing against the functional requirements is described and an assessment of how the systems can be incorporated into Business as Usual (BAU) has been conducted.

A brief overview of the technical integration is discussed focusing on the knowledge gathered including some of the challenges faced if these systems were to be integrated into BAU.

The report then concludes with how the systems built and commissioned for the NTVV project could be scaled to cover the entire SEPD licence region with the associated costs and timeframes for this roll out to occur. The full report detailing the commissioning of the NME has been described in **SDRC 9.6** delivered in December 2013. The full report detailing the commissioning of the NME has been described in **SDRC 9.2c** delivered in January 2014.

1.2. Link to Methods and Learning Outcomes

Method 1 as defined for NTVV (see SET203 New Thames Valley Vision bid submission) seeks to link network reinforcement to a better understanding of electricity consumers. The DMS has been set up to import the LV network including all customers and can be used to identify where Low Carbon Technologies have been installed. As a result the DMS can become the central system for managing and controlling assets at the LV and in customer premises.

Method 2 - Interact with demand response provided by both large and small businesses. The DMS will be configured to invoke load shed events via the Automated Demand Response (ADR) interface when implemented.

Method 3 - Tactically deploy power electronics and electrical energy storage on the low voltage networks. The DMS will act as the mechanism to manage telemetry data being received from the Energy Storage and Management Units (ESMU) being installed as part of the NTVV project and act as the mechanism to send controls to the ESMUs to trigger charging and discharging, phase balancing and voltage regulation.

Learning Outcome 1.1.3 - Managing high volumes of data in a DNO environment. This report identifies how the creation of a DMS that encompasses the LV network and substation monitoring has increased the quantity of data being stored from secondary substations. The DMS is a subscriber to the NME and can receive data to maintain the LV network from any alterations to running conditions or new connections introduced. Additionally, the high scale volume of substation monitoring data from the 220 installed sites has given the DNO a new insight into how large scale data can be managed from secondary substations and how this data can be used to better understand the flow of energy on the LV network.

2. Data availability

2.1. Data preparation

2.1.1. Data preparation for the GIS

The NTVV project has built and commissioned the DMS system as declared in January 2014 and reported this successful delivery in SDRC 9.2c.

A key requirement of this system was to integrate the DMS with the GIS system commissioned as the Network Modelling Environment. This integrated solution would allow both the bulk import of the LV network and the ability to perform incremental updates to the LV network based on new connections or changes to the normal running arrangement of the LV network.

The trials to maintain the synchronised DMS and GIS system ensure that any changes made by field staff to the running of the network are reflected in both systems with the business benefit that the changes only need to be made in the GIS and the patch is replicated to the DMS by the use of the Common Information Model (CIM) - electricity as defined by IEC 61968. The CIM standards for electricity distribution networks define how information can be exchanged between IT systems to create enterprise level integration between separate applications. It is precisely this functionality that this project is exploiting to establish the benefit to the wider business and other British and European network operators.

The majority of the data needed to establish the DMS was prepared in other systems and then imported into the NTVV DMS. Examples include the existing HV network for the Bracknell area which was imported from the existing Scottish and Southern Electric Power Distribution (SSEPD) SCADA system and the LV network for the Bracknell area which has been imported into the DMS from the NME across the Common Interface Model (CIM) interface.

To ensure that the data being imported was in a sufficiently sound and valid state to be imported, significant time and effort needed to be taken to ensure the source data in the existing SSEPD systems was accurate and of sufficient quality to be imported into the

DMS. It was recognised early in the project, that to utilise the new systems for trials the DMS that the system and data needed to be of a high degree of accuracy. In addition it was a requirement to ensure operational staff were sufficiently confident in managing the LV network in Bracknell with the new system.

To ensure that the source data held on existing systems for all substations in the study area was of the required accuracy level, the project undertook a series of substation surveys to ensure that the source data was valid and make any changes to the existing systems before the data was extracted to create the NTVV systems. The surveys were conducted on 570 substations at a cost of around £40 per site. The implication of scaling this work up to the entire Southern Electric Power Distribution (SEPD) licence region is considered later within this report in **Section 5.1**.

Where the information in the source systems was found to be inaccurate or had not been maintained in line with expected business processes, the correct information was fed back to data administrators responsible for maintaining the asset and GIS systems to ensure that the corrected information was updated. The substation surveys ensured that the correct labelling of the feeders was maintained, that accurate fuse sizes were held in central systems, and that the position and type of LV isolation was correctly captured.

Where the substation survey found any inconsistency with the feeder labelling or the position and type of LV isolating equipment was not created in the appropriate position, the existing GIS system was amended to reflect the actual installation at site. This work took an average of 20 minutes per site. The consequence of performing this to the wider SEPD licence region is discussed in **Section 5.1** of this report.

In addition to the substation surveys, the existing GIS needed some modifications to ensure that the internal view of the substation objects that were in the study area could be imported into the DMS in a format where the fuse objects and transformer objects had a clear section of busbar between them. This was to ensure that when a control engineer or LV depot scheduler was interacting with the diagram the individual components and associated menu items had a degree of separation. In the existing GIS system this is not an issue as the objects are not used to drive actions but to store information of the plant item. To complete this work for a single site took an average of

10 minutes per site. Again, the consequence of scaling this approach to the wider SEPD licence region is discussed in **Section 5.1** of this report.

Once the data had been captured and amended in the source GIS system for the Bracknell area, the source GIS data was in a position to be imported into the NME in a position where it could be readied for further import to the DMS via the bulk load process.

If additional information is required on the detailed data preparation for the NME then please refer to **SDRC 9.6** fully details the commissioning of the NME and the data preparation.

2.1.2. Data Preparation for the DMS

In addition to the work required to ensure that the source GIS data was in a suitable state to be imported to create the DMS representation of the LV network for the Bracknell area, the DMS had to be configured to ensure that it was in a position to accept the imported network.

The first step to allow the imported network into the DMS was to create an area on the diagram and a district zone of the DMS diagram that would accommodate the area of network being imported to create the LV network. The management of the network from an HV perspective is managed by a series of control zones. These are separated both geographically and by voltage. For the central southern licence regions operational system this ensures that a dedicated control engineer has control of a specific voltage for a defined geographic area. As this was the first instance of the LV network being created in a DMS, the system needed to be set up to receive the network by the creation of a new zone to introduce the network from the CIM data and ensure they were added to that zone.

One other configuration change needed for the DMS was to alter to the existing representation of the 11kV transformer object that existed in the existing operational SSEPD DMS for the southern licence region.

To ensure that all plant and equipment installed on the LV network can be imported to a DMS for the LV network, the appropriate symbols need to be created to reflect the physical plant in substations, pole mounted apparatus or ground installed. The DMS must to be set up to receive the data from the NME and as such work is required to create symbols and template objects to be able to create the LV network from the exported LV circuits. As a result, the cartographic team need to understand the objects that would be imported and create a symbol within the DMS to map each component class against. A full audit of all installed plant on the LV network needs to be conducted against the objects held in the GIS to ensure that symbols are created for all objects that are to be imported. All of these symbols need to be able to be interacted with and have menu options defined and created that represent the manual procedure that can be enacted upon that plant item. For any additional plant item that has not been used in a DMS context previously an object must be created which can take up to 5 days to achieve.

As well as the new items, a significant amount of work was required to change and substitute the existing 11kV transformer objects already held in the DMS. For the existing operational DMS systems used to monitor and control the EHV and HV networks, the last point of visibility for a control engineer using the existing DMS is the 11kV transformer object.. As a result, the existing 11kV transformer object in the DMS has never shown the secondary windings where the voltage is transformed to 230V per phase as there has never been an operational requirement. The NTVV project has taken this view down to the customer level, giving the control engineer a view of the LV side of the transformer As these objects reside in both the 11kV view of the HV network and on the LV view of the network (these views are known as ‘worlds’ operationally) an amendment had to be made instead of creating an entirely new object. A process was established to perform a symbol substitution for the transformers in the project study area based on the primary substation and a scripted process was deployed to limit the manual effort required to deploy this change. The figures below show a traditional 11kV transformer in the operational system, the amended transformer with the addition on the secondary windings as depicted in the 11kV world and the same object held in the LV world.

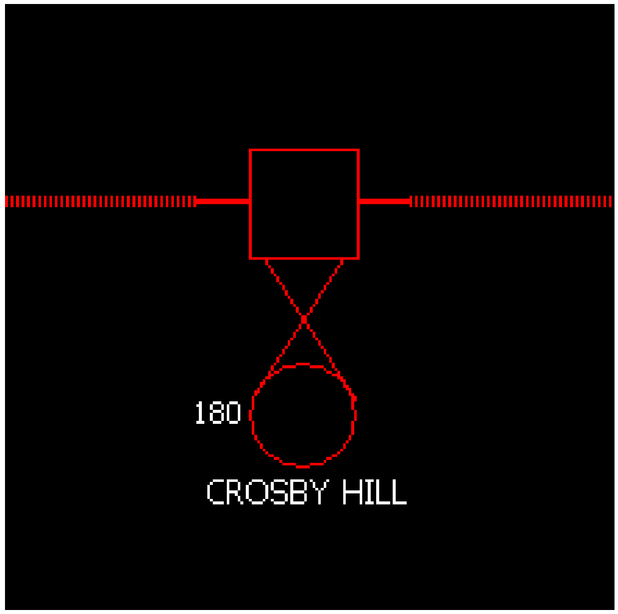


Figure 1 – 11 kV substation representation in the DMS prior to the symbol substitution

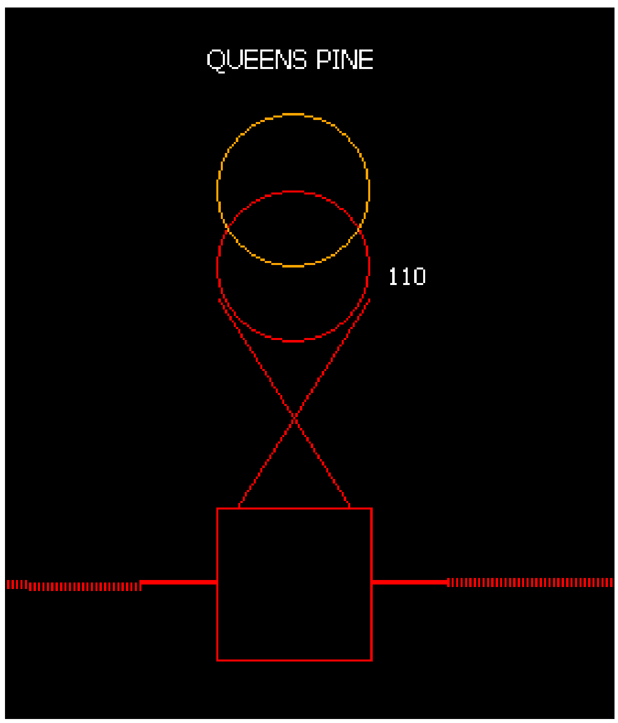


Figure 2 – 11 kV substation representation in the DMS with the secondary windings attached indicating LV network imported

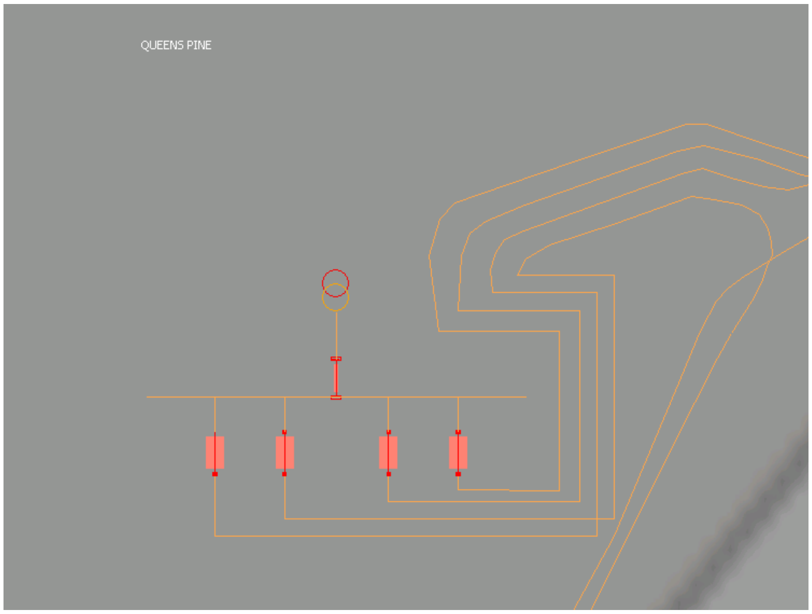


Figure 3 – 11 kV substation representation in the DMS with the secondary windings attached indicating LV network imported

In addition to the plant, the cables and conductor sizes and types must be fully populated and synchronised with the GIS to ensure that all cables and conductors are set up in the DMS to be graphically represented on the diagram or a default cable type of unknown will be created for the section.

Whilst there may be a significant pressure to deliver systems early and begin the import of data, the source data must be of a sufficiently high standard prior to importing any data to subscriber systems. The validation of the imported data becomes far less complex and time consuming if the majority of the work is completed prior to import. If any rework is required post import, this can take significantly longer to rectify than if the time was allocated earlier in the project.

2.2. Works required

In order to create the LV DMS for the NTVV project, the elicitation of the requirements of the new system had to be defined, the base system had to be built, the applications installed and configured, the base network diagram and system configuration imported from the operational system, the end user access and role based permissions defined and interfaces designed to exchange information and messages with other systems. All of these tasks take time to deliver and if the end system will have any control of live electrical apparatus, then the inherent security of the system, interfaces and access routes must be fully considered and a risk based approach to information and system security designed into the architecture from the project inception. The NTVV project spent a great deal of time and effort to ensure that the final delivered system was commissioned with the same focus on physical and logical security measures as a traditional SCADA system. The full description of the process taken to commission the system has already been reported in full in **SDRC 9.2c** and this report will focus on the learning gained from the commissioning.

The base build of the servers for a DMS capable of importing the DMS would take an average of 7 months. This time includes performing the analysis on what the system capabilities need to be, delivering the base infrastructure, installing the required software onto the systems and configuring the base templates and objects.

It should be noted that if additional infrastructure such as dedicated local area networks or firewall devices need to be procured, installed and commissioned then the lead time for delivery of the base systems will take considerably longer. A minimum of 6 months should be allocated for to deliver these items based on the experience of the NTVV project.

As the NTVV project had to implement several system upgrades of the DMS software over a compressed time frame, it was not possible to integrate the NTVV DMS within the operational SCADA system used by the business.

In terms of capturing the learning from the NTVV project from the system commissioning perspective, the engagement of all stakeholders was vital in ensuring that the project could deliver a new DMS system with all of the security and functionality of a SCADA system in a very compressed time frame. The project engaged with all of the teams that would be needed to ensure the delivery was a success at very early stages of the project initiation. These groups were not only the SSEPD teams but extended into the SSE corporate departments such as procurement, telecoms and IT. In addition, every stakeholder group was represented on the Innovation Steering Board by a senior member of staff to ensure that any risks or issue of delivery had senior visibility and could be addressed.

Once the system was commissioned, built and had passed all of the user acceptance tests the project was in a position to begin to hand the system over to operational staff. The teams working directly on the LV network in Bracknell were able to propose the trials that will be conducted by using the tools for both planned operations and in fault conditions to assess the optimal level of control for the LV network.

2.3. Indirect costs

The indirect costs associated with the build of the DMS and the operation to date has generally been driven by minor changes to field based equipment. These changes to product configuration at the request of the project team have been to deliver additional functionality for installed equipment.

An example of this is the changes to the substation monitoring equipment installed on the project based on new functionality requested by the project. It was proposed that by using an existing alarm the substation monitor could potentially capture the electrical characteristics of a blown fuse and send an alarm back to the DMS. As a result changes were made to the DMS template and the most recently created substation monitor objects to incorporate this amendment. Whilst this functionality was not a firm requirement for the initial design of the substation monitor it clearly had significant benefit for the operational teams who manage the LV network. As a result it was a clear area where additional resources and time were devoted to deliver this new functionality. This would assist the operational teams and adds an additional benefit to the business case for the deployment of substation monitoring.

An additional indirect cost of the DMS was the need to run a duplicate shadow system in addition to the live operational system. Had the business been able to accommodate the project need then a single solution would have reduced the time to build the system and the associated overheads of managing separate systems. However, there were clear requirements for the need to run parallel systems to accommodate the NTVV trials, the primary driver being the ability to quickly perform system upgrades to software. An operational SCADA system would struggle to accommodate these upgrades without extensive effort from support teams, control engineers, business test resources and the required system down time associated with a major SCADA system upgrade. Running the systems in parallel gave the project the ability to perform three major upgrades over a nine month period that would be incredibly difficult to achieve in a safety critical DMS managing alarms, tele-control and telemetry (including automated switching schedules) from the HV and EHV networks. The additional indirect costs of managing two systems in parallel are associated from the extra hardware, operating system, database platforms and application support functions that need to be taken into consideration.

Additionally, the DMS must be flexible enough to accommodate new technologies that are delivered on the LV network. It would be expected that these future low carbon technologies should be incorporated and managed via a DMS. An indirect cost may be the configuration changes needed to an LV DMS to accommodate such technology. An example of this would be the Bidoyng, the Rezap or the Lynx; all of these products are manufactured by Kelvatek and manage the restoration of supply on the LV network. If a DNO intended to deploy these technologies or products from other suppliers on their network and if an LV network view had been created in the DMS then it is logical that a DNO would want to integrate these technologies into their DMS. The project team and budget would not pick up the cost of any reconfiguration to accommodate these technologies however the project team that commissioned the system may be needed in an advisory capacity to support any such initiatives.

3. Functionality against business and functional requirements

As fully described in the report **SDRC 9.2c**, there were 4 specific sets of requirements for the DMS. Each of these was focussed on the project deliverables but had a clear cross over to business needs as research transitioned to a defined business driver.

The requirements focused on ensuring that the system was able to meet the needs to deliver the trials as defined in the project bid submission and that the outputs could deliver an understanding of how the system could improve the existing business processes currently utilised by the organisation to manage the LV network.

The requirements were broken into four distinct areas and are assessed against the business and project functional requirements below.

3.1. LV Operations

These requirements were aimed at ensuring that the enhancements in the upgraded DMS would operate for the LV network and allow the engineer the ability to perform operations on an individual phase basis. Additional functional requirements were designed to ensure that field operations that are specific to the LV network were captured and were represented using the system. These requirements also defined the business processes that would be utilised to perform specific work on the LV network using the DMS as the centre of operations for managing planned activity and working under fault conditions to restore customer supply.

To validate that the functionality of the system met the agreed requirements for performing operations on the LV network several iterations of user acceptance testing (UAT) were performed. Any defects were logged in a central quality management system that tracked any software or configuration issues.

The UAT ensured that the LV operational requirements were delivered in full accordance with the business requirements. The full validation of these requirements will be achieved when the project moves trialling the DMS with the operational teams working on the LV network in Bracknell and identifying the optimal level of LV network control from use of the DMS.

3.2. LV Model

These requirements defined the look and feel of the symbols for network objects in the DMS when imported from the NME. This ensured that the symbology was consistent with the existing objects in the operational SCADA system utilised on the HV and EHV networks and the delivered systems would have a similar 'look and feel' for operational users.

Again a full round of UAT was performed on all of the requirements to ensure these objects met the functionality defined in the approved requirements. All objects have been signed off to ensure that they meet the needs of the business and are in a position to be utilised for the physical trials of the DMS with the operational teams.

3.3. CIM

These requirements define the mechanism of loading the LV network and introducing changes to the network in the DMS via the CIM interface from changes made within the NME. They ran through all of the possibilities for introducing changes automatically from the NME in all possible scenarios and defined the business process that would need to be followed to attempt to ensure that the systems remained in full synchronisation throughout the project.

These requirements were tested in isolation and approved prior to the bulk load of all substations and LV network into the DMS, and have been delivered in full for the project needs. In terms of the full set of business requirements, there were some modifications needed to the mechanism in which the CIM was delivered if the system were to be scaled by a factor of 100. These alterations to the requirements are discussed in detail in **Section 5.5.**

3.4. ADR

These requirements defined how the ADR functionality would be deployed in the DMS. They stated the conditions where load shedding could be achieved via the scheduled load shedding mechanism and how the system could be configured to work in the event of a pre-defined circuit overload to initiate a fully automated demand side response event.

To date the requirements for the ADR interface have yet to be fully tested due to technical issues with configuring interface between the DMS and the ADR Demand Response Automation Service (DRAS). A full explanation of the technical issues is described in **Section 4.2.4**.

The work to create all DMS objects that will trigger the ADR events has been fully developed and created at the position of the customer with ADR enabled. In addition the aggregated ADR components that hold several ADR enabled sites have been configured. The DMS interface has been set up and the final configuration changes to the message format are underway.

The configuration to send a load shed event based on an analogue threshold breach has been designed and implemented. This requirement can be triggered from data received from either a secondary substation monitor or the loading data from an 11kV primary feeder held in the NTVV historian database which has been retrieved from the PI to PI interface as defined in **Section 4.2.1** below.

4. Integration

To integrate separate IT systems in a seamless way has been a major challenge for the project. To import the 35,500 customers from the NME and validate every transformer, fuse, link box, cable segment, pole, service connection and LV customer has taken significant time and effort.

In addition, the ability to manage high data volumes from deployed substation monitoring to the DMS has proved challenging in terms of system performance but has been overcome and the project has shown that large scale data volumes can be managed within the DMS.

The ability to integrate a DMS with external systems such as ADR has also been much more technically complex than first anticipated and has yet to be delivered fully compliant based on the technical requirements.

4.1. Communications

4.1.1. GPRS Communications Integration

The integration of mobile communication to the DMS was a straight forward process. The system utilised the existing SSEPD infrastructure to connect to the cellular network provider network. As a result the internal configuration of existing systems and agreements with existing service suppliers was not onerous. An additional Access Point Name (APN) was configured, a new VLAN created to land the traffic on and a new routing table added to the existing network switches to route the traffic for the NTVV APN to the NTVV DMS servers. The logical network design for the GPS connection to remote devices is shown below.

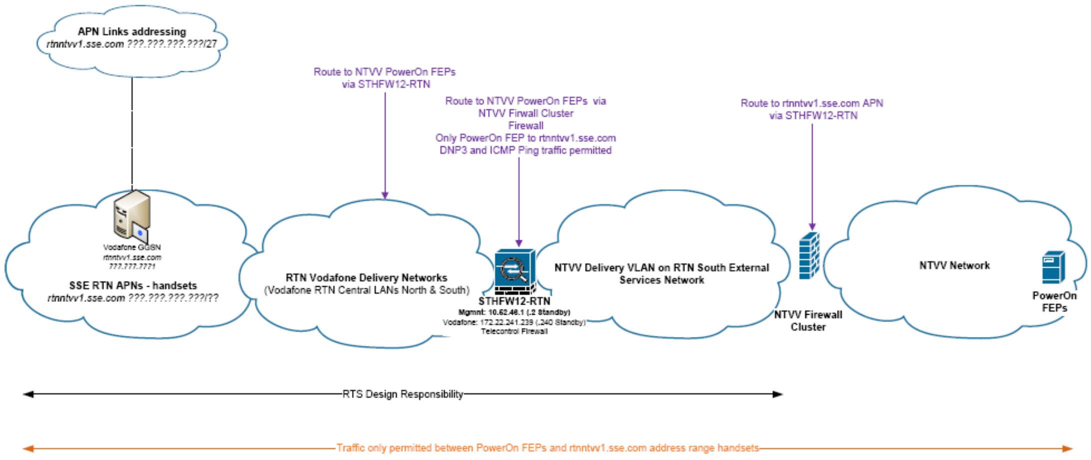


Figure 4 – Logical network design for GPRS communication to the NTVV DMS

Had the project not had access to the existing infrastructure required to transmit data over cellular networks and had needed to provision this network infrastructure independently, the cost of delivering the base network routing equipment and the creation of dedicated trunks to a mobile provider would have been significant and delivering the first tranche of substation monitors utilising this equipment would have been more difficult.

4.1.2. Virtual Private Network Communications Integration

The DMS has been set up to have interfaces to other systems using dedicated Virtual Private Network (VPN) connections. A VPN is a network connection that utilises an existing public telecommunications network infrastructure to provide secure access to remote resources. Typically an internet connection is used and the connection is secured by a shared key between the separate networks.

The DMS has a VPN connection between the GE Digital Energy datacentre to retrieve data from the GE hosted end point monitor, Smart Meter Operations Suite (SMOS) to transfer customer energy usage information to the NTVV data historian.

The DMS has a secondary VPN set up to the Honeywell Building Solutions to enable the communication of building management system data to be held in the DMS and allow the sending of load shed event signals to participating companies that have been signed up to the ADR programme.

4.2. Interfaces with other systems

4.2.1. PI Historian Interface

The DMS has a native interface to the data historian, known as the ‘RTPIF’ process. This interface is already used by the operational SEPD and SHEPD operational SCADA systems; it takes the real-time data from monitoring devices on the network and passes them to a defined data historian. The data historian interface required very little configuration to set up and minimal effort was needed to set all the data points polled from the DMS to be stored in the historian as time series data.

There have been no noticeable issues with this interface during the project to date. However, it should be noted that the DMS will store any telemetry data that it receives in temporary files should the data historian not be available. As a result, particularly when streaming large data volumes, the amount of system storage available to the DMS and configured for the temporary volume must be sufficient to accommodate the recovery time objective of the historian system. If the storage provision is not adequate then the volume will be exhausted and any additional data will be lost until the interface to the data historian has been restored.

4.2.2. PI to PI Interface

The NTVV DMS has been set up to receive data from the SEPD live DMS to show the status of the network configuration at the four 11kV primary substations that feed the customers in Bracknell. This information is passed between the data historians linked to the SEPD DMS and the NTVV DMS. The data historian for both the operational business and the project is the PI System from OSISoft. This data historian has an interface known as PI to PI. This interface allows data held in one system to be passed to another in near real-time. The interface has been set up to pass the state of the 11kV circuit breakers in the operational DMS and these identifiers (open/closed) are passed to the NTVV DMS. As a result if any circuit breaker monitored by the operational SCADA system operates, the corresponding data item in the NTVV DMS is shown as either opening or closing. The DMS has been configured to ‘fetch’ this data point from the NTVV data historian and can then perform the dressing on the diagram accordingly. This functionality allows the LV network that has been imported to be shown as live or dead based on the operational state of the 11kV network held in a separate system.

In addition to the state of the 11kV circuit breakers being transferred across the PI to PI link, the project has set up the live DMS to retrieve the outputs of the current transformers on all of the 33/11kV transformers and all 11kV feeders at the four primary substations and send it to the live data historian. This data is then pulled into the NTVV data historian, and then fetched by that data point in the NTVV DMS. This gives the project team the ability to monitor the loading on the 11kV system.

4.2.3. SMOS to PI Historian interface

The NTVV project has installed 250 end point monitors in the homes and businesses of consenting project participants. This has enabled the project team and academic partners to obtain half hourly energy consumption data and, should a project participant have any form of microgeneration installed, the amount of energy exported back onto the network, again at half hourly intervals. The data is held on the end point monitor and is requested once per day from the head end system hosted by GE known as SMOS. The data is then held in the SMOS database prior to a process being initiated to send the data, across the defined secure VPN connection, to the SSEPD hosted data historian. This interface also utilises the RTPIF interface delivered as standard with the DMS.

In addition to the issue concerning data storage provision highlighted above, the SMOS to data historian interface is also reliant on additional network infrastructure to ensure that the data is passed from the head end system to the data historian. This infrastructure includes firewalls and the internet connectivity of the relevant organisations. To date there has only been one minor issue with the VPN between the GE and SSEPD datacentres and this has not affected the data transfer of customers’ end point monitor data to the historian.

If the use of end point monitor data or bulk smart meter data was being used for operational purposes, such as in a distribution state estimation scheme, then the criticality of the interface would be increased and the uptime and associated service level agreements with technology providers would need to be increased accordingly.

4.2.4. ADR Interface

The NTVV project has engaged with industrial and commercial customers in the Bracknell area to recruit 30 buildings to the ADR scheme. This programme aims to see if customers are willing to participate in reducing the load in their building when a request is made by the network operator. The project has been undertaking load shed events via the Honeywell Building Solutions online portal for all ADR customers that have had the controllers installed and load shed strategies defined. The project team and project partners have been creating an interface between the DMS and the Honeywell hosted DRAS.

The VPN was configured and tested between the DMS and the DRAS and the connectivity on the required Internet Protocol (IP) ports are allowed between the two systems.

Each of the systems was setup and configured in line with the design for the interface and the message being sent to request a load shed event and the project move to the integration testing phase.

The sending of a Simple Object Access Protocol (SOAP) message that would initiate a load shed event to a customer has been tested with revised configuration being made to the ADR scheduling engine within the DMS. Several iterations on the testing of the ADR SOAP message were conducted and a valid message format is still under creation. The project partners have been working hard to resolve the issues and we are anticipating that the interface will be available for trial in 2015.

The key learning is that even with standard internet protocols and messaging formats, aligning two organisations to a common message structure and configuring the systems to receive a message and process the instruction can take longer than first anticipated at the bid submission stage.

4.2.5. ESMU and ADDM Interface

The project is installing 25 ESMUs on the network in Bracknell to trial how electrical energy storage and power electronics technology can be combined to manage power factor, thermal constraints and voltage to facilitate the connection of renewables on the LV network. The DMS will be used to receive the data from the installed ESMU devices and pass this to the data historian. A separate and internally developed system known as Active Distribution Device Management (ADDM) will take the data from the historian and by using smart control algorithms, identify the optimal function that the ESMU should perform based on the state of the network and send the control via the DMS to the ESMU. The SOAP interface utilised to send the control has been defined and the security and whitelisting of controls that can be triggered remotely have been identified and a process created to set the permissions on these controls. The controls will then be sent via the Distribution Network Protocol (DNP3) to the ESMU devices.

The high level architecture of the ADDM service and the interface between the ADDM system and the DMS is shown in the figure below.

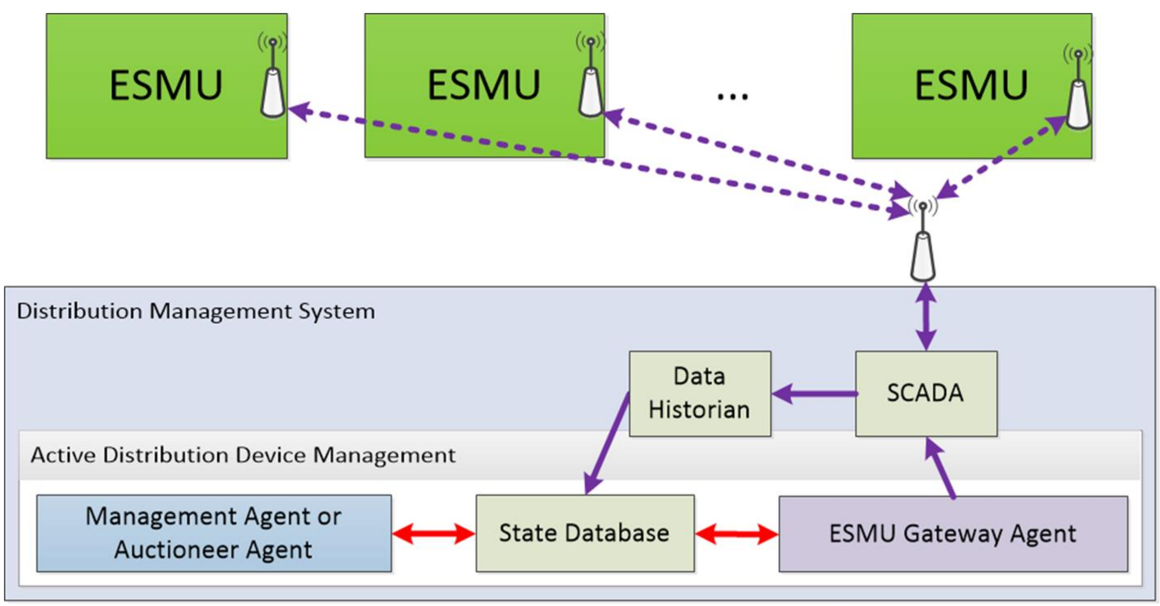


Figure 5 – High level architecture of the ADDM service and the DMS interface.

The ESMU interface uses the standard DMS DNP3 setup for a primary scanning device and will involve the use of a hybrid router set up using a hardwired ADSL network connection with a GPRS router as a backup option.

The interface from the ADDM system to the DMS has the ability to issue a control to a remote live electrical system without human intervention and as a result close attention is needed to be paid to the security of the interface. Any potential for issuing SCADA controls to remote systems can have safety considerations and as such a great deal of time has been spent ensuring that only a permitted proxy server can issue the commands to the DMS. Further details of the ADDM system will be forthcoming as this aspect is delivered into 2015.

The SOAP interface has been tested and confirmed to be working and represents the first implementation of an ancillary system sending a control into a DMS within the SSEPD business. This interface allows the ability for other third party smart control systems to be incorporated into a DMS and given permission to control plant, which could lead to more autonomous devices being installed on the network as the business moves into RIIO-ED1.

5. Scalability

Having commissioned the system it is an obvious requirement to see how the solution could be implemented at scale. The scaling exercise has been based against the SEPD licence area which is approximately 100 times greater than the study area in terms of customer connections. The scaling will take into account the time and cost implications to scale the system; it will also look at whether the same methodology and approach would be used and whether the scaling of the system has any limitations of scale that would affect existing operational use. Having assessed all areas of the delivery of the DMS and scaled, to deploy a solution of similar functional requirements would take 12 months to deliver based on the NTVV delivery model.

5.1. Data Preparation DMS

5.1.1. GIS Source Data Preparation

The project undertook a process to gather information to validate the data held in the central systems. The cost of the surveys was around £40 per site an average of six sites per day were visited dependent on the distances between the sites and the type of location (urban, dense-urban, semi-rural, rural, etc.). To scale this to the total number of secondary substations would be feasible but would be incorporated into the standard scheduled substation inspections carried out annually. This would drive down the cost of the physical site visit and data capture.

The NTVV project identifies that there was an issue with the quality of some of the source data in the GIS system, this stemmed from not all circuits having full connectivity. There may be a section of network where the connectivity at a pole or joint is not complete when the initial network was digitised. This does not have a negative consequence for the GIS system and this functionality is not intrinsic requirement for operational purposes. However, when this data is imported into the DMS where the state of a section of network is ‘dressed as either live or dead, then the full connectivity has greater importance. The GIS source data to accommodate a full roll out would need to be validated for full connectivity prior to being exported to the DMS to reduce the amount of data improvement iterations.

The data was recorded back into a project specific database and the information passed to administration teams who ensured that central systems were updated with the corrected information for any site. The GIS updates took 30 minutes per site to be incorporated manually. This ensured that the source data was in a position to be imported into the NME and was sufficiently valid for further import to create and build the LV network in the DMS. Basing the scaling for the GIS cleanse on the 74,909 secondary substation objects in the live SEPD SCADA system a manual GIS tidy would not be appropriate as the overall time to deliver this would be in excess of 1000 weeks of effort. As a result, additional development time would be needed to create a programmatic and automated process for delivering the wide scale changes to the GIS system. However it should be noted that by introducing an automated process to make wholesale changes to any system or component will introduce a greater risk of unforeseen issues with any changes that are not manually validated at the time.

Another consideration that should be taken into account when preparing source data to be imported at scale into a DMS for LV network management is the ability to define designated control zones to equipment and networks. For the NTVV project this did not cause an issue as the entire LV network for the Bracknell area is managed day to day by a dedicated team from the Slough depot. If an entire licence region was imported, all of the source data would need to be labelled so that it was assigned to the correct depot ownership. The mechanism to assign control zones to the NTVV LV network was performed post installation by running control scripts that assigned the NTVV zone to all components that reside below the existing LV isolating equipment. The LV isolating equipment is the domain of the 11kV control desk owner and any instruction to operate this isolation must be conducted with the authorisation of the central control room.

In order to scale the GIS preparation and ensure that it is of suitable quality to be imported into the DMS, many cycles of importing the data into a test system may be required where the data validation can be performed in defined areas. It is advised that no more than a single primary substation of data is loaded into a test system at a time. The data validation exercise can then be performed and corrective actions taken to revise the source data to the required confidence level. The import can then be repeated before the area is signed off as ready for import.

5.1.2. DMS Data Preparation

The majority of the work required to scale the LV network import from a DMS perspective has been completed on the NTVV with the exception of any new objects or components that needed to be created. To create a new symbol within the DMS can take up to five days of effort and there are known items of apparatus on the network that have not yet been configured. These include phase balancers, voltage regulators and capacitor banks. To ensure that the DMS is in a position to import any component on the LV network, the object must exist in the NME and an associated mapping made in the CIM specification to transfer the object.

Any additional symbology needed to be created in the DMS requires five days of effort from a cartographic resource. As such a full audit of all objects and plant that reside on the LV network or any new equipment that may be about to be installed would need to be captured and then created.

In addition, an audit of cable and conductor types must be conducted for all LV networks and these items incorporated into the DMS. The creation of additional cable types could take up to 10 days of effort in configuration.

As highlighted in **Section 2.1.2**, the 11kV transformer needs to be replaced with a new object to be able to import an LV network. Based on the experience of the NTVV project the process took around two hours to perform the symbol substitution for the substations that were imported. Scaled to the entire SEPD licence region this process could take up to six weeks of effort to be rolled out.

5.2. System Build

The systems commissioned for the NTVV project were in line with the specification of the live SEPD and Scottish Hydro Electric Power Distribution (SHEPD) DMS systems; the physical infrastructure of the system does not need to be scaled further and the system could be utilised as is to accommodate the imported LV network, substation monitoring using secondary scanning lines, targeted end point monitoring bulk data load and additional SOAP interfaces to other systems to drive smart technologies and demand response programmes held on separate systems.

5.3. Substation Monitoring

The installation of substation monitoring for the NTVV project was focussed on collecting very granular, 5 second energy data at up to 325 substations. This requirement was to ensure that the academic partners on the project could get near real time data on the flow and usage of energy across Bracknell. To put the level of monitoring currently deployed in 220 substations in Bracknell into context, at present we have 41,000 telemetered data points in PI across the entire SEPD licence region that covers 2.8 million customer connections and over 85,000 11kV substations. These telemetry points monitor the HV and EHV networks and use primary scanning for real time control of plant using fixed line and permanent connection to the operational DMS. In the operational system, there is some secondary scanning which is installed at strategic switching points on the 11kV network to allow automated switching schedules to reconfigure the network to get as many customers back on supply in a fault situation. At this stage approximately 10% of the 11kV network has tele-control enabled switching apparatus and uses secondary scanning.

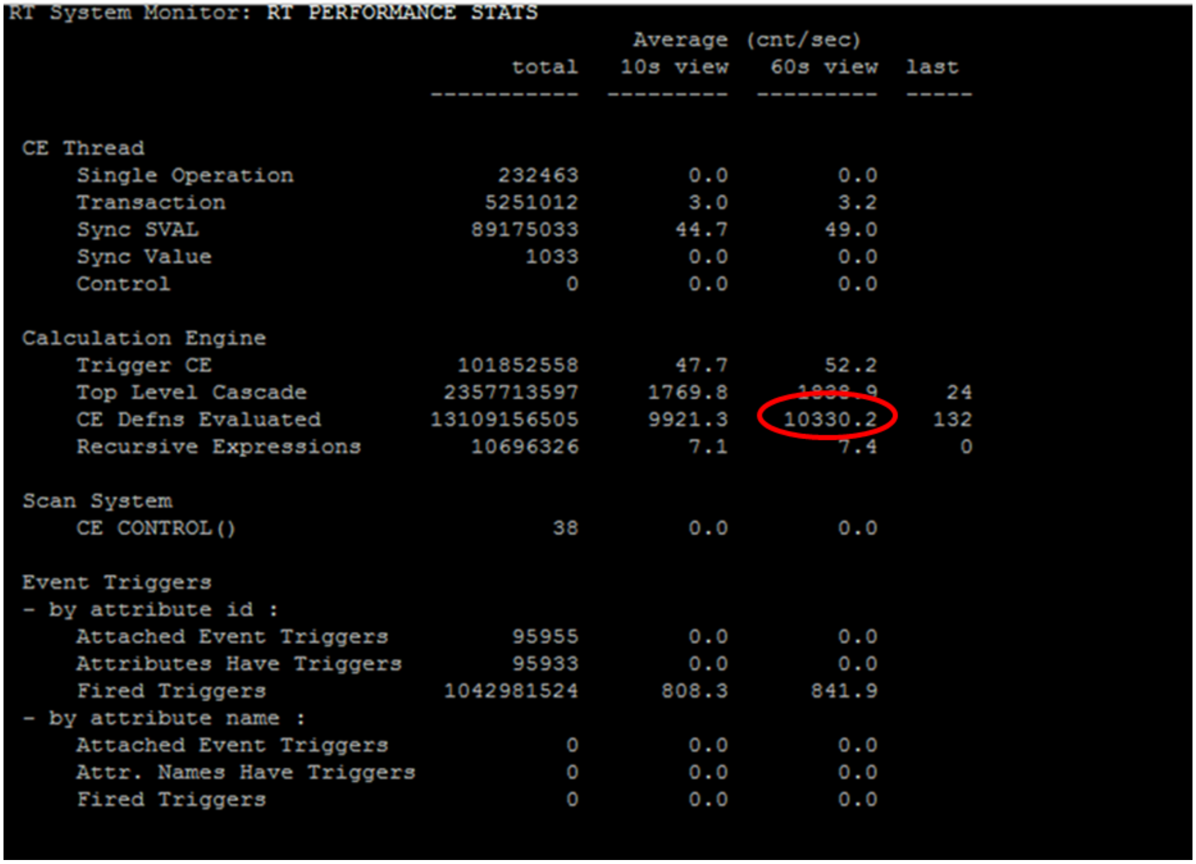
The system has been set up with defined substation monitoring templates, an underlying process to create all of the SCADA point linkages and a mechanism to export all of the PI tags from the DMS. This ensures that the business can take the templates and processes already created in the NTVV project for the commissioning of substation monitoring and deploy this technology into business as usual operations.

The 220 substation monitors installed for the NTVV project collect data from over 52,000 telemetered points including substation, end point and meteorological measurements. As mentioned the project has rolled out five second scanning to obtain granular data from the Bracknell area to be able to see the intra-half hour energy usage as well as some data that gives the half hourly maximum, minimum and root mean squared average. The total number of individual data items transmitted daily (based on an average 4 feeder substation at every site) is over 250 million streamed data points and 350 million half hourly calculated data items. This level of monitoring of secondary sites would not be cost effective to be deployed to all sites across the business and both licence regions.

A more realistic use case for substation monitoring would follow the secondary scanning scenario where the devices report on exception where an alarm is issued or can be remotely dialled to collect bulk data periodically rather than constantly streaming data.

One use case for constant streaming of data would be where there is a smart technology installed on the LV network that is controllable. This could include Energy Storage Units or EV charging points. Where a smart control system needs near real-time information on the conditions at the substation, certain devices could be set to stream data to the DMS. It is advised that due to the criticality of communications networks needed to manage such devices, primary scanning should be utilised to control live electrical apparatus.

The limitation of the total number of scanning monitoring at the five second frequency relates to the DMS system to process the transactions. At the current project levels of 220 substations monitor installations the DMS polling every five seconds for data takes a considerable amount of system processing to manage the level of transactions. At the current deployment the DMS server is performing on average 10,000 evaluations of calculations per second. This can be seen in the screenshot of the PowerOn Fusion system performance statistics in the image below.



```
RT System Monitor: RT PERFORMANCE STATS
                                            Average (cnt/sec)
                                 total    10s view   60s view  last
                           ----------- ---------  ---------  -----

 CE Thread
     Single Operation           232463       0.0        0.0
     Transaction               5251012       3.0        3.2
     Sync SVAL                89175033      44.7       49.0
     Sync Value                   1033       0.0        0.0
     Control                         0       0.0        0.0

 Calculation Engine
     Trigger CE              101852558      47.7       52.2
     Top Level Cascade      2357713597    1769.8     1838.9     24
     CE Defns Evaluated    13109156505    9921.3    10330.2    132
     Recursive Expressions    10696326       7.1        7.4      0

 Scan System
     CE CONTROL()                   38       0.0        0.0

 Event Triggers
 - by attribute id :
     Attached Event Triggers     95955       0.0        0.0
     Attributes Have Triggers    95933       0.0        0.0
     Fired Triggers         1042981524     808.3      841.9
 - by attribute name :
     Attached Event Triggers         0       0.0        0.0
     Attr. Names Have Triggers       0       0.0        0.0
     Fired Triggers                  0       0.0        0.0
```

Figure 5: screenshot of average calculations being evaluated in the PowerOn Fusion system for substation monitoring.

As a result the DMS system would not be appropriate to use if the firm requirement from a DNO was to monitor all 11kV substations at a high frequency; a secondary DMS or Object Linking and Embedding (OLE) for Process Control (OPC) compliant system would need to be setup and a mechanism identified to present the substation monitoring to the control engineer via an additional interface.

5.4. End Point Monitoring

The DMS has been configured to be the system utilised to transfer data from the point monitor head end system hosted by General Electric (GE) and to send the data over the established VPN to the NTVV data historian. The NTVV project has deployed a limited number of end point monitors to ensure that the academic partners had access to half hourly energy usage data for Bracknell before the roll out of electricity supplier led smart meter roll out had fully commenced and the establishment of the Data Communications

Company (DCC). As a result for the project the DMS was set up and configured to pass the data from SMOS to the data historian. For the 250 end point monitors deployed on the NTVV project the process to hand data from SMOS to the historian has not posed any performance issues or been impeded by any technical issue. The system could be scaled to manage a large volume of smart meter data and has the functionality to manage alarms and events as standard.

However, a system to manage the true scale of smart meter data by a DNO, the ‘last gasp’ event of a customer losing supply, any events related to voltage and the associated storage of usage data would need to be well embedded in any existing customer and outage management system. As this has not been proved in the NTVV project we cannot state that this solution would be sustainable at scale. In addition, the mechanism to manage and issue SSL security keys to transfer encrypted data to SMOS would not scale to a wide scale and would need to be a fully managed and automated process by Public Key Infrastructure (PKI).

5.5. LV CIM Import

The import of the LV network for the Bracknell area has been a successful operation. The majority of circuits have been programmatically imported without issue and as represented in the source NME system. The import and creation of a SCADA system with a geospatial LV network has been a success and senior management responsible for the day to day management of the network are looking closely at the trials being run using the DMS. As such it has been a major deliverable of the NTVV to analyse how the system and processes to load the LV network could be delivered into BAU for an entire licence region. For the scaling desktop exercise, the SEPD licence region has been utilised.

At present, the greatest number of components in the SEPD operational DMS relate to 11kV substations. Of all equipment in the operational system, these components account for around 80% of all objects. In the SEPD system there are currently 85,124 objects that are classed as an 11kV secondary substation. It should be noted that not all of these substations will have an LV network connected and some could well be single customer sites. Analysis of the range of 11kV substations indicates that around 12% would be single customer substations that take an HV supply. As a result the scaling for the LV network that needs to be imported would be 74,909 substations.

For the project we loaded a total of 523 LV substations from the NME into the DMS. This represents 0.7% of all substations in the SEPD licence region. If the DMS was used to import LV networks for the full SEPD licence region where 11kV substations have LV networks, the quantity of components would increase significantly. For the 523 substations loaded into the DMS, the total number of components increased from 1,798,726 in the SEPD live DMS to 2,125,148 for the NTVV DMS, an increase of 326,422. This is an average of 624 additional components per substation.

To import the LV for all 74,909 sites would represent an increase in the total components to be held in the DMS of 46,743,216.

It should be noted that when components are referred to this does not include cables and conductors. These objects are classed as external conductors and are not represented by the figures above. For the 523 substations loaded into the DMS, the total number of cables and conductors increased from 276,466 in the SEPD live DMS to 341,875 for the NTVV DMS, an increase of 65,409. This is an average of 125 additional busbars, mains cable segments and service connections per substation.

The scaled import of the LV network for all substations would therefore represent an increase in the total number of busbars, mains cable segments and service connections by 9,368,494.

The system does not have an intrinsic limitation on the total number of additional items that can be loaded and the system could be scaled to import all of these items.

An additional and perhaps more key learning point relate to the CIM import and the issues of scaling the system is presented when an entire licence area of LV network is required to be loaded into a DMS. For the NTVV project, the bulk load of the CIM data for 523 substations took around 15 days. During this time the project team were advised not to make any other changes to the system as this had the potential to cause a conflict. In addition, the system performance was degraded while the bulk load of the new substation objects, cables and conductors and customers was introduced. For the NTVV project this did not cause any issues. However, if the same mechanism was followed on an operational system this would lead to problems with the day to day management of the HV and EHV networks and could impact on core SCADA functionality. As a result it has become apparent that the loading mechanism would need to be altered and the process to cut the data over once prepared in CIM format would need to change. Work has been ongoing at GE Digital Energy to create an updated loader process using a Structured Query Language (SQL) bulk loader which would reduce the time needed and minimise system performance issues that were experienced with the CIM loading process utilised on the NTVV project. For this new process, the replication of the system would need to be stopped to one of the servers, the bulk data loaded and then the systems merged together again. This process is used when a major operational system upgrade takes place and is a well documented procedure for any customer utilising the PowerOn Fusion product.

Once the bulk load has been completed, a significant piece of work would be required to perform the substation and link box tidy exercise that was undertaken on the NTVV project. For the NTVV project and the 523 substations and 548 link boxes had to be manually tidied by hand. The reason for this is that the busbar and link box objects are imported without any clearly defined geospatial reference points and as a result, manual effort is needed to straighten and align these objects. For the imported network in the NTVV project this activity took two weeks. This could not be expected to be achieved on a network over 140 times larger and alternate methods would need to be identified to overcome these issues. It is proposed that either additional development time is aligned to this in GE Digital Energy to create a better mechanism for representing these objects or an internal view of the transformer and distribution board are created with a hyperlink type arrangement to remove the need for geographic tags (similar to the view in the NME).

A further limitation of the use of the CIM to import the LV network at scale comes from the CIM standard itself. In the current CIM standard, there is only one attribute for LV isolation. This attribute had to be used for both the LV isolation at the substation and the LV links. Having to utilise a single object to represent these varied network assets raises an issue with regard to how the objects and their menu options are created for that piece of equipment. If the CIM specification had separate object types for removable isolation, hinged isolation and LV links then the specification would better serve the import of LV networks with regard to these specific components. Another solution would be to offer all menu items regardless of the plant at site however this could cause confusion when instructing operations to field resources from a centralised control engineer.

5.6. ADR

As the ADR interface has yet to be delivered and trialled due to the technical issues listed above, it is difficult to define how this interface would operate at scale. The DMS with LV and HV connected customers would have no limitations in holding the required ADR components to deploy this technology at scale upon the successful integration of the DMS to the DRAS. Additionally the VPN connection between the systems has no limitation on the quantity of data that can be transmitted across this communication interface.

6. Transfer to Business as Usual

The updated DMS that shows a representation of the LV network that has been imported from a GIS system. The system has been widely demonstrated to operational teams, depot manager and the Head of Power Distribution Operations South.

The processes for managing the LV network using the DMS have been defined to ensure that they meet the operational guidelines for staff today working on the network and ensure that although the method of setting to work may be altered by using a control system, the operations on the ground are not altered.

The processes for deploying substation monitoring at scale have been made production ready ensuring that if this technology proves of value to the business it can be quickly moved from the NTVV DMS system to the live system with minimal rework or alteration.

There is a keen interest in the NTVV project DMS and the ability to manage the LV network using a centralised system with defined business processes to ensure a standard approach to operations across the business.

The business have aligned teams and dedicated depot staff to the project to deliver the trials using the commissioned DMS. Additionally the project has had access to a senior control engineer throughout the project to date. This resource was key during the commissioning stages and the definition of the requirements to ensure that the system met the expectations of a control engineer. Moving forward varying modes of control operation will be trialled from fully controlled operations of the LV to delegated control at the depot level to understand the optimal future business as usual

In addition the ability to track faults in a DMS view centrally and in conjunction with the HV and EHV networks give operational staff the ability to plan network reconfiguration on the LV network to better aid restoration of supply to customers in a fault situation. The LV DMS also has the ability to maintain any abnormal running arrangements in one system will give management the ability to produce reports on these conditions and make informed justification for total expenditure investment needed across the business.

Another area of the project which has already been taken by the wider business as a standard is the use of the CIM standard for future IT system integrations. The business is delivering an IT asset management system upgrade. In addition maintaining existing functionality of the system and improving workflow management and integrating the new asset system to the procurement, the new system requirements defined the ability to share information on the plant and cables using the CIM format. The sharing of equipment details and asset information of apparatus that comprise the distribution network was identified as a precursor to other system upgrades that are planned by the business over the RIIO-ED1 period and the ability to exchange information using the CIM standard has now become an intrinsic system requirement.

7. Conclusion

The DMS and NME have proved that systems that have a linkage to a source data repository and that are able to export/import data in a CIM compliant format can be achieved and that the introduction of large areas of LV network using automated process can be delivered by a DNO.

In addition a DMS is able to manage and handle unprecedented volumes of data from both external systems and from monitoring equipment deployed at secondary substations.

The DMS system delivered for the NTVV project can be configured to manage a wide range of new technologies previously not directly controlled via a DMS system such as ESMUs.

Whilst the CIM standard for distribution networks is used to share information on the LV network there are certain constraints around the number of objects that are defined. For HV networks this would not represent an issue but on the LV network where similar plant may have various ways of being operated a compromise must be made and additional manual post import work is required to define the operating procedure at individual sites.

Source data must be of a high degree of accuracy, connectivity and validity prior to importing the LV network. As much time as can be devoted to source data improvement must be allocated to ensure that the number of iterations of source data modifications is required before the data can be considered in a production ready state.

Scottish & Southern
Electricity Networks