SDRC 7.3 and 8.5

DEVELOPMENT OF NETWORK MODEL AND PRICING MODEL

SAVE
Solent Achieving Value from Efficiency

Scottish & Southern Electricity Networks

Solent Achieving Value from Efficiency

Solent Achieving Value through Efficiency (SAVE) is an Ofgem funded project run by Scottish and Southern Electricity Networks (SSEN) and partnered by the University of Southampton (UoS), DNV GL and Neighbourhood Economics (NEL). The innovative programme evaluates the potential for domestic customers to actively participate in improving the resilience of electricity distribution networks and thereby defer the need for traditional reinforcement. The government has forecasted an increase in electricity demand of 60% by 2050 meaning peak demand is likely to grow to six times higher than what the network was designed for.

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A document named Solent Achieving Value from Efficiency (SAVE), Operational Report by TNEI follows this document.

Figures

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EXECUTIVE SUMMARY

The Solent Achieving Value from Efficiency (SAVE) project is a Low Carbon Network (LCN) Fund project which is being led by Scottish and Southern Electricity Networks (SSEN) in partnership with DNV-GL, University of Southampton (UoS), Future Solent, Neighbourhood Economics and EA Technology.

The project aims to trial and establish to what extent energy efficiency measures can be considered as a cost-effective, predictable and sustainable tool for managing peak and overall demand as an alternative to network reinforcement.

A number of real-world customer field trials have been completed as part of the SAVE project to assess the effectiveness of four energy efficiency interventions in reducing and/or time-shifting demand for electricity in a representative sample of the household population of the Solent region. The four intervention methods are:

- Low energy lightbulb installation within the premises of customers.
- Data-informed engagement campaign with customers.
- DNO price signals issued directly to customers plus data-informed engagement.
- Coaching of customers at a community level.

As part of the process for assessing the effect of these interventions on the network and to assess where and when they may be economically viable when compared to conventional reinforcement, there was a requirement to develop a Network Investment Tool, which applies a Customer Model to a Network Model and allows a Pricing Model to investigate the economic efficiency of the available SAVE interventions and capital interventions. This tool can make these investigations on LV, HV and EHV networks.

The creation of the Network Model and the Pricing Model are a dependency for other parts of the project to be able to investigate network impacts from the customer interventions and to describe benefits created for customers.

The report shows that the Network Model and the Pricing Model enables users to study the LV network, technically and economically across several growth scenarios and compare the performance of different investment strategies which take advantage of both SAVE interventions and physical interventions. The purpose of this report is to introduce and demonstrate the Network Model and the Pricing Model at a high level rather than in technical detail.

This report also shows how users can compare the effect and cost efficiency of SAVE interventions and physical interventions at the HV and EHV levels of the network.

This report describes the capability that is now available within the Network Model and Pricing Model and also any learning points encountered in developing this capability. The capabilities introduced will then be used by other workstreams in the SAVE project to investigate knowledge gaps.

This report fulfils requirements associated with Successful Delivery Reward Criteria 7.3 and 8.5.

1

INTRODUCTION

1.1 Project Background

The SAVE project aims to trial and establish to what extent energy efficiency measures can be considered as a cost-effective, predictable and sustainable tool for managing peak and overall demand as an alternative to network reinforcement. The project targets domestic customers only, and the measures trialled include deploying technology, offering a commercial incentive and taking an innovative approach to customer engagement.

On completion of the project a suite of models to assess a particular network's suitability for demand reduction through energy efficiency measures will have been developed. These will allow informed investment choices to be made between using customer engagement and energy efficiency measures as opposed to traditional technology-based measures and 'smart' solutions. These investment choices will be made by modelling of the electrical network and the economic choices that can be made.

1.2 Objectives and Knowledge Gaps

The purpose of this report is to show how the Network Model and the Pricing Model have been developed. This report directly supports two of the SAVE project objectives which are to:

- Produce a Network Model revealing modelled impact from measures
- Produce a Network Investment Tool for DNOs

The capabilities demonstrated within this report allow other workstreams to fulfil these objectives and by employing these capabilities the SAVE project will also be able to close down the following knowledge gap.

- Understand what the most cost-effective energy efficiency measures for DNOs are

The deployment of the Network Model and the Pricing Model will also allow the SAVE project to address the following learning objectives:

- To determine the merits of DNOs interacting with customers on energy efficiency measures as opposed to suppliers or other parties.
- To gauge the effectiveness of different measures in eliciting energy efficient behaviour with customers

1.3 Structure of the Report

The structure of this report is as follows:

- **Section 3:** Introduces the architecture of the Network Model and the Pricing Model
- **Section 4:** Provides an overview of the user requirements for this tool and their needs.
- **Section 5:** Describes the application of the different reports available within the Network Model and Pricing Model.
- **Section 6:** Introduces the functional specification of the Network Model and Pricing Model and signposts evidence of completion.
- **Section 7:** Provides a summary of work undertaken and learning points.

1.4 Wider Modelling Reports

Successful Delivery Reward Criteria (SDRC) 7.3 and 8.5, Network Model and Pricing Model serve as one of four modelling reports that SSEN is publishing to evidence, describe and share learning on the delivery and outcomes of the SAVE project's Network Investment Tool (NIT). To this purpose, the Network Model and Pricing Model report serve as an evidence report centred around build and solo usage of each of these models, which combined with the Customer Model and project data produce the NIT (see Figure 1).

The project's other reports will be found referenced throughout this document and will provide greater context into:

- SDRC 2.3: Customer Model- will provide evidence of customer model build and solo use value to the network owner when combined with SAVE data.
- SDRC 8.5 and 8.6: Customer and Network Model report and Pricing Model Report which provides a detailed insight into how DNO's can use each of the models for a range of different analytical purposes
- SDRC 8.2: Network Investment Tool which runs the three models described above with the SAVE data on a series of case study networks to show outputs of the tool, how these may be interpreted and the build of business as usual business cases around the SAVE trials.

2

GLOSSARY

This table defines any abbreviations used within this report.	
ADMD	After Diversity Maximum Demand
BSP	Bulk Supply Point
CM	Customer Model
DLL	Dynamic Link Library
DNO	Distribution Network Operator
DUoS	Distribution use of system
EGD	Embedded Generation for Distribution
EV	Electric Vehicle
HP	Heat Pump
HV/EHV	High Voltage/Extra High Voltage
LCT	Low Carbon Technology
NIT	Network Investment Tool
NM	Network Model
PM	Pricing Model
PV	Photo Voltaic
SAVE	Solent Achieving Value from Efficiency
SDRC	Successful Delivery Reward Criteria
UoS	University of Southampton

3

THE ARCHITECTURE OF THE NETWORK MODEL AND THE PRICING MODEL

The SAVE project aims to produce a Network Investment Tool that will allow DNOs to assess and select the most cost-efficient methodology for managing electricity distribution network constraints. The model will consider the effectiveness of different types and degrees of energy efficiency interventions, as well as more traditional techniques for network reinforcements as tools for the management of networks by DNOs.

To achieve this aim, a set of three comprehensive models working in unison are being developed by the SAVE project to deliver an overall software tool that network planners will be able to utilise to manage distribution network challenges more effectively.

Figure 1 depicts an overview of the overall hierarchy of the analysis tool to be delivered by the SAVE project.

The set of models include:

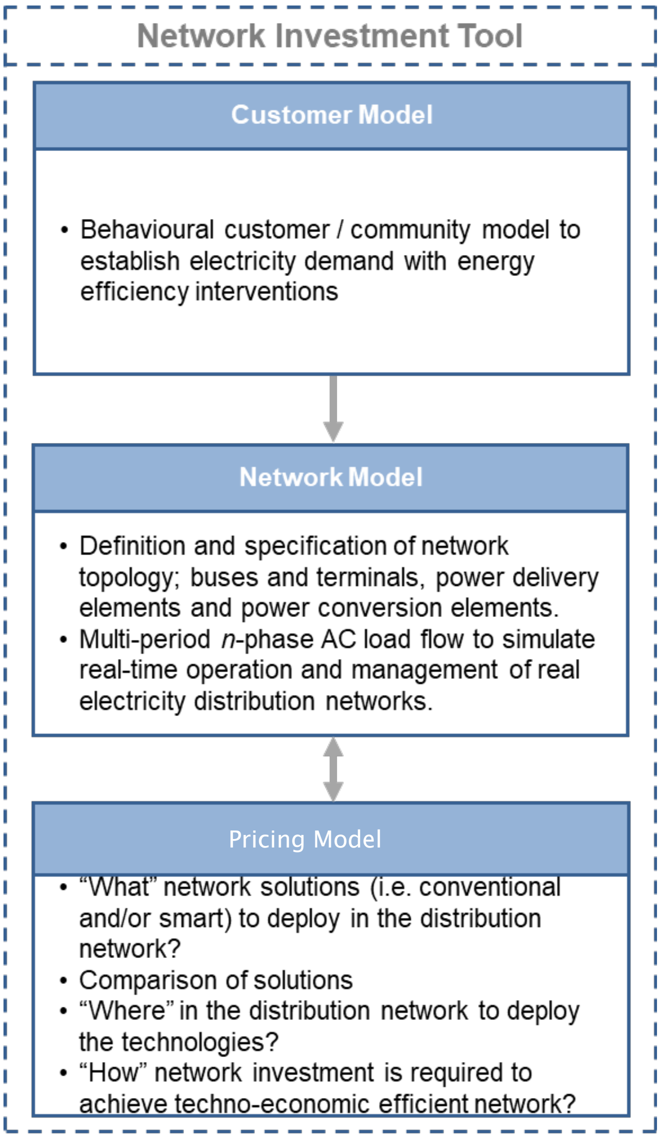
(i) The **Customer Model** represents the behaviour of trial participants in response to energy efficiency interventions. This will provide customer behaviour data to the Network Model. This model is the responsibility of the UoS.

(ii) The **Network Model** simulates the real-time operation and management of LV electricity distribution networks and calculates at which point in time a network under investigation would reach the limit of its capacity across a number of different load growth scenarios and different capacity interventions. This model is the responsibility of EA Technology.

(iii) The **Pricing Model** ranks the economic investment performance of each traditional asset-based solutions for network infrastructure development against non-traditional network solutions' whilst considering the technical constraints associated with the operation and management of the network. This model allows an analysis of LV, HV and EHV networks. This model is the responsibility of EA Technology.

Although the Network Model and the Pricing model referred to as separate entities, they are accessed by users within the same Microsoft Excel environment.

Figure 1: Conceptual overview of the overall tool



This report discusses the delivery of the Network Model and the Pricing Model. The Network Model and the Pricing Model are implemented in one single environment. This environment uses a Microsoft Excel interface that is supported by a backing store, which is implemented as a database in Microsoft Access. A simplified map of the environment is shown in Figure 2.

The environment provides users with 5 types of analysis, which are known as:

- Single Assessment
- Future Assessment
- Multi-Scenario analysis
- A tariff calculation module
- A storage price comparison module
- HV/EHV module

These five analysis options are implemented over 18 Microsoft Excel tabs. There are a further 13 Microsoft Excel tabs which can be used to manipulate network data, customer data, growth assumptions or study settings.

Although the main user experience is through a Microsoft Excel interface, the majority of the business logic is embodied in a Dynamic Link Library (DLL). The DLL interfaces with the Excel environment, the load flow engines and the Microsoft Access backing store.

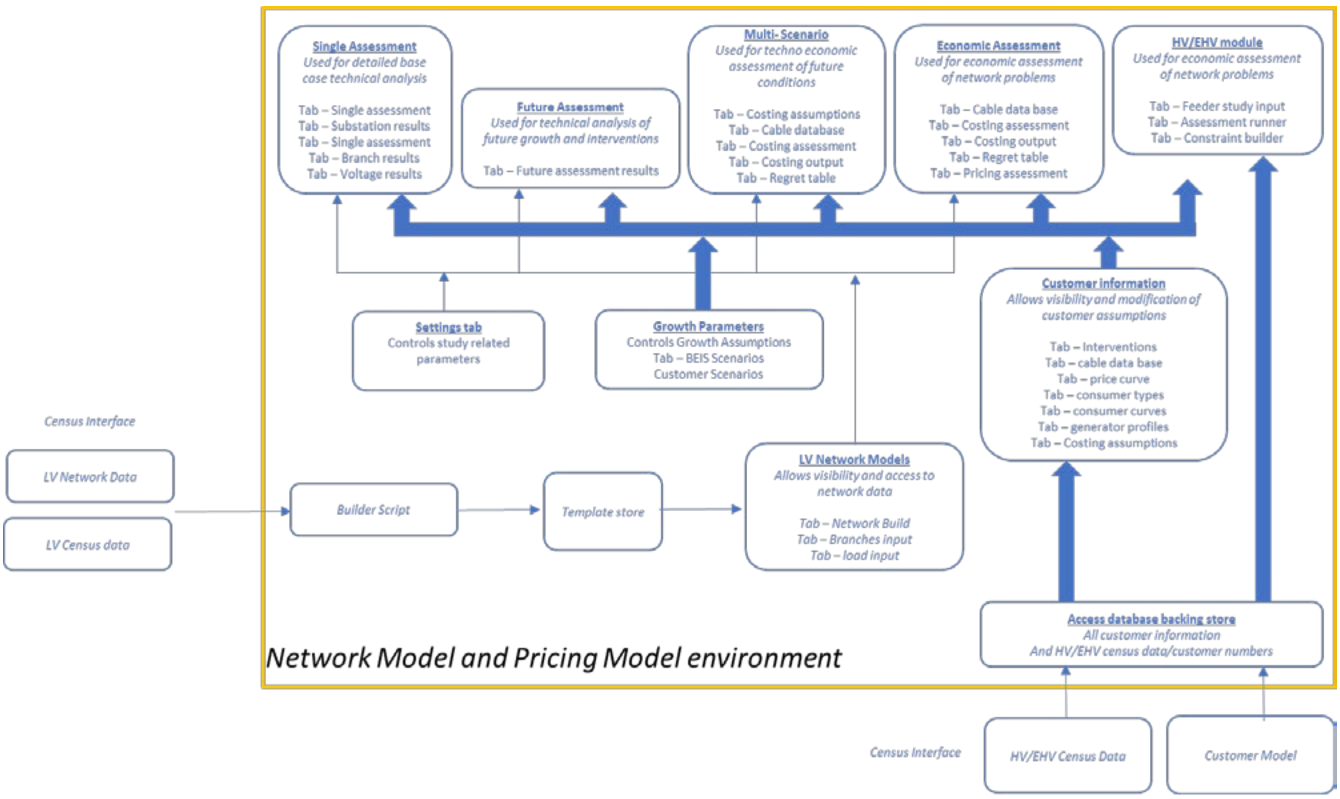
As shown in Figure 2, the parameters that have been created by the Customer Model can be loaded into this environment via the backing store. This process requires users or administrators to move the data across the interface.

Network templates can be created and loaded into the template store by loading the network data and census data into the builder script.

Output reports are published on the Microsoft Excel tabs listed in each of the 5 assessment areas which are discussed further in section 5.

It must be stressed that Figure 1 reflects the original concept of the tool and since the start of the project the architecture has evolved to overcome problems and implement efficiencies. As such different and distinct modules were referred to at the beginning of this project which are now, contained within one overall environment. Therefore, these terms are not necessarily referred to in this document, section 7 shows how the additional specification has been adhered to.

Figure 2: A conceptual overview of the Network Model and the Pricing Model



4

USER REQUIREMENT STATEMENTS

The overall SAVE Network Investment Tool serves the needs of several different types of users within SSEN. This section describes the needs of these users.

4.1 LV network planner

The LV network planner seeks to mitigate problems on LV feeders and HV/LV transformers. An LV network planner will have the following requirements of the SAVE Network Investment Tool.

- All available network data and customer data has been loaded into the overall environment by an administrator.
- Confidence that the analysis of the network is realistic, the studies will need to use a model of diversity between customers that are realistic such as ACE 49[1].
- The LV network planner will need to be able to make the following investigations:
  - Network compliance investigations capable of between a year ahead and many years ahead timescales. This can be done using the single assessment or future assessment analysis as discussed in 5.6 and 5.7.
  - LV network investment studies to understand the least risk yet most cost-effective investment strategy across uncertain growth forecasts. This can be achieved using the multi-scenario analysis as discussed in section 6 and the least regret analysis.

An LV network planner will need to be able to consider the technical aspects of the following capacity interventions.

- SAVE Interventions[2]
  - Low Energy Light bulbs
  - Data-informed engagement campaign
  - Price signals and data-informed engagement campaign
  - Community Coaching
- Smart Interventions
  - Electrical Storage
- Conventional interventions
  - Feeder Replacement or overlay
  - Feeder Split
  - Transformer Replacement

As described across sections 5.3, 5.6, 5.7, 6, 6.2 and 6.3 users are able to explore the technical aspects of these interventions.

1 ACE 49 refers to ACE 49; ENA, 1981. "Report on Statistical Method for Calculating Demands and Voltage Regulations on LV Radial Distributions Systems", Energy Networks Association, 1981. This document outlines a standard for designing LV networks including a process for the treatment of diversity between customers.

2 In principle, additional customer led interventions not investigated under the SAVE project can be considered providing there is an adequate model of customer behaviour.

4.2 HV/EHV Planner

HV and EHV planners are responsible for ensuring that the HV network and EHV network remains within capacity limits. When the network is forecast to exceed limits, they are responsible for instigating capacity interventions. An HV/EHV planning engineer will have the following needs of the Network Investment Tool.

- A HV/EHV planner will need to use the tool to calculate whether the use of price signals or SAVE interventions will be an effective alternative to a proposed reinforcement of a network group. For the purpose of the SAVE project, it has been deemed acceptable to limit this to reinforcements under winter peak conditions only. Section 6.4 explains how this can be achieved.

- This methodology shall align with existing capacity planning tables used by HV/EHV planners. Section 6.4.2 explains how this need has been pursued.

- HV/EHV planners will need to be able to understand the total amount of flexibility resource within a constraint group which could be used to solve a network problem. Section 6.4.3 shows how this comparison can be made.

- HV/EHV planners will need to know the maximum price that should be paid for flexibility services before a conventional reinforcement is better value for customers. Section 6.4.3 shows how this comparison can be made.

- HV/EHV planners will need to know how many customers will need to be recruited to provide flexibility services as a means to solve a network problem. Section 6.4.3 shows how this assessment can be made.

4.3 LV Connections planning engineer

LV connections planning engineers are responsible for helping people connect to the electricity network. This section describes the needs of these users.

- An LV connections planning engineer will need to understand how much capacity is available upon a feeder and whether it is forecast to run out of capacity. This can be achieved using the single assessment or future assessment analyses as discussed in 5.6 and 5.7.

4.4 Commercial Engineer

- Commercial engineers consider the links between customer behaviour, tariffs or flexibility tenders and the cost of running the network. The needs of these users are:

- Commercial engineers would like to be able to model the link between Distribution Use of System (DUoS) price signals or flexibility contracts and the amount of power consumed by different customers under winter peak conditions. This will enable aggregation techniques to scale up different customer types into an overall price elasticity model of customers upon a feeder/LV Substation/Secondary feeder or user-defined constraint group.

  Sections 6.3 and 6.2 describe how users can assess the economic and technical sufficiency of price signals or the use of storage interventions. The multi-scenario assessment also considers in which conditions price signals or SAVE interventions would be the most advantageous capacity intervention.

- Commercial engineers would like to be able to deploy aggregation techniques to scale up different customer types into an overall model of customer response upon a feeder/LV Substation/Secondary feeder or user-defined constraint group and allow HV/EHV planners understand the costs of these approaches in comparison to reinforcement costs. Section 6.4.3 describes how this comparison can be made.

- Commercial engineers would like to be able to understand the following information

  - How much domestic flexibility is likely to be offered within a geographic area?

  - How much domestic flexibility is likely to cost to mobilise?

  - Whether domestic flexibility alone can satisfy a network constraint?

Section 6.4.3 describes how this comparison can be made for HV or EHV systems.

5

APPLICATION

This section describes the application of the key elements of the Network Model and the Pricing Model and its supporting modules.

5.1 Load Flow Engines

To calculate current flows and voltage drops, the Network Model uses two load flow engines, DEBUT and EGD (Embedded Generation for Distribution). These load flow engines are used both within EA Technology's WinDEBUT software package. These two load flow engines have different strengths and weaknesses.

- DEBUT is a mature software package that provides voltage drops and asset utilisations from customer load models. Developed by EA Technology, it is implemented in Fortran and, unlike most load flow tools, DEBUT uses a unique calculation process to take account of diversity following the ACE 49 design method and is able to solve networks without having to resort to iterative methods which can sometimes have difficulties converging on a solution.

- EGD (Embedded Generation for Distribution) was originally developed by EA Technology to allow the assessment of generation in the DEBUT software. The EGD engine is a traditional load flow engine utilising the common Newton Raphson iterative method.

  The main reason for including it in this proposal is that the code is readily adaptable for alternative uses, such as advanced probabilistic methods, and it allows us to model generation on LV circuits. The Newton Raphson[3] approach has not traditionally suited deployment of the ACE49 approach to modelling of customer diversity.

The Network Model automatically presents the output from EGD or Debut depending on the needs of the report in question. There are however some dilemmas between simultaneous use of DEBUT and EGD.

DEBUT can be used for the assessment of circuits where it is expected that generation connected to the circuit would be negligible and also where the interventions can be adequately modelled using the specific methods defined in ACE49. DEBUT does not calculate load flows at 30-minute resolution but instead reports on the periods of worst-case loading for each day.

EGD calculates power flows in active networks at 30-minute resolution using a Newton Raphson approach. But because it is an iterative approach, it is not well suited to implement the ACE 49 approach to simulation of diversity as such it assumes network conditions are described by the average customer demand per 30 minute period without modelling of the standard deviation values as prescribed by ACE49. This approach is considered justified in a network where there is reverse power flow as modelling the network using the concept of design demand described in ACE 49 would underestimate the amount of power flowing towards the source substation.

Because these two engines give outputs with different time framing with different approaches to diversity assumptions they are used to inform different reports as described in sections 5.7, 6, 6.2 and 6.3.

5.2 How to build a network

Users are able to load ready-made templates into the Network Model via the network build tab. For these templates to be available to the user, .csv files containing the network data and customer allocations will need to have been prepared and loaded into the templates folder.

The Network Model uses a representation of the network in terms of nodes and branches. In all cases, nodes and branches can be declared using the schema summarised in Table 1.

3 Unlike Debut which uses a linear network approximation, the Newton Raphson method is a numerical method which is used to solve network load flow equations by iterative steps.

Table 1: Branch and node data format

Heading	Description
Near Node	The ID number of branch node nearest to a network source. This ID number must be allocated by the user. Each node can accept more than one branch.
Far Node	The ID number of nodes furthest from the source. This ID number must be allocated by the user. Each node can accept more than one branch.
Length	Branch length in metres
No of Phases	Number of Phases
Cable Type	Specifies the cable type to be used on the branch. Draws data from the data library
Number of Customers	Number of customers connected to Far Node
Customer Type	Reference to customer load profile
Annual Consumption (kWh)	Annual consumption of the customer type
Main / Service	Branch purpose i.e. LV main or service

Figure 3: Example of a network template in a .CSV format

SUB=100 500															
1	11	1	TRIPLE	CONSAC 1	0	0	0	0		0			MAIN	ON
2	68	206	TRIPLE	CU 0.1	12	0	0	0	GAPAB	1000	AUTO		MAIN	ON
3	70	31	TRIPLE	CU 0.25	3	0	0	0	GAPAB	1000	AUTO		MAIN	ON
4	125	12	TRIPLE	WAVE 300	0	0	0	0		0			MAIN	ON
11	14	129	TRIPLE	CU 0.1	4	0	0	0	GAPEB	1000	AUTO		MAIN	ON
11	12	56	TRIPLE	CU 0.1	0	0	0	0		0			MAIN	ON
12	13	75	TRIPLE	CU 0.1	2	0	0	0	GAPEB	1000	AUTO		MAIN	ON
14	21	5	TRIPLE	CU 0.1	0	0	0	0		0			MAIN	ON
14	15	1	TRIPLE	WAVE 95	0	0	0	0		0			MAIN	ON
15	16	6	TRIPLE	WAVE 95	1	0	0	0	GAPEB	1000	AUTO		MAIN	ON
16	17	28	TRIPLE	CU 0.06	0	0	0	0		0			MAIN	ON
17	20	89	TRIPLE	CU 0.06	4	0	0	0	GAPAB	1000	AUTO		MAIN	ON
17	18	13	TRIPLE	CU 0.06	0	0	0	0		0			MAIN	ON
18	19	78	TRIPLE	CU 0.06	4	0	0	0	GAPAB	1000	AUTO		MAIN	ON
21	22	84	TRIPLE	CU 0.3	3	0	0	0	GAPAB	1000	AUTO		MAIN	ON
21	38	58	TRIPLE	CU 0.06	0	0	0	0		0			MAIN	ON
22	45	45	TRIPLE	CU 0.1	0	0	0	0		0			MAIN	ON
22	58	9	TRIPLE	CU 0.1	0	0	0	0		0			MAIN	ON
22	23	11	TRIPLE	CU 0.1	0	0	0	0		0			MAIN	ON
23	24	1	TRIPLE	CU 0.1	0	0	0	0		0			MAIN	ON

Figure 3 shows an example of a network template within the .CSV format which can be loaded into the Network Model without the need for the user to manually input each line into the user interface.

These templates can be automatically created by using a scripting process which combines data from their Customer Model and their network data records to express what types of customers are connected at which node in the network template.

Instead of using templates, users can build custom networks within the network environment by using the branches input and load input tab.

Figure 4: Example of template selection tab

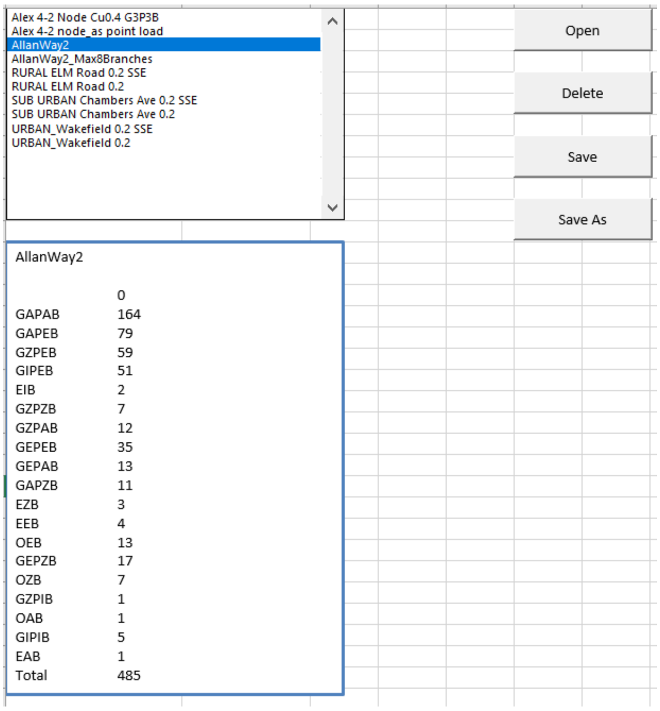


Figure 4 shows an example of how users can load templates into the Network Model. The top box within this figure shows the list of networks that are available for study. The second box lists the demographics of customer types within this model. Each customer type e.g. GAPAB, relates to a customer type from the Customer Model.

Users also have access to the Branches input tab and the Load inputs tab to either view the structure of the network and customers or alternatively build custom models as shown in Figure 5 and Figure 6.

A key feature of the load input tab, as shown in Figure 6, is the ability to allocate loads to phases to simulate a global phase imbalance target. This allows users to replicate customer phase allocation on the basis of observations made at the source substation. The significance of the load input fields is discussed further in 5.3.

Once the network connectivity has been loaded into the Network Model it is presented in a visual format to the user to help verify the model. An example of this is shown in Figure 7.

Figure 5: Example of Branches input tab

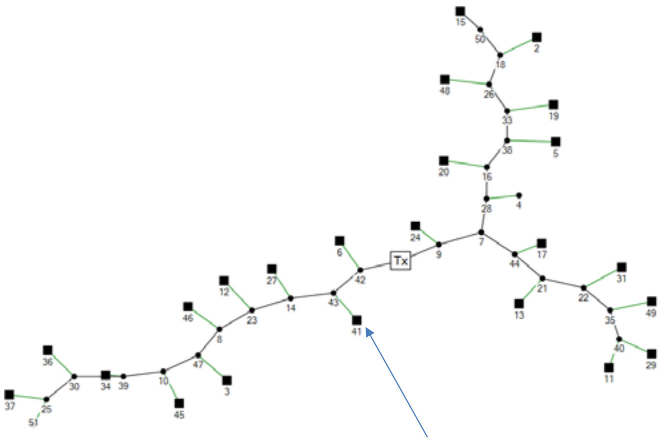
Transformer Rating [kVA]	500
Substation Node	100

Near Node	Far Node	Length (m)	No of Phases	Cable Type	Main / Service	Status
1	11	1	TRIPLE	CONSAC 185	MAIN	ON
2	68	206	TRIPLE	CU 0.1	MAIN	ON
3	70	31	TRIPLE	CU 0.25	MAIN	ON
4	125	12	TRIPLE	WAVE 300	MAIN	ON
11	14	129	TRIPLE	CU 0.1	MAIN	ON
11	12	56	TRIPLE	CU 0.1	MAIN	ON
12	13	75	TRIPLE	CU 0.1	MAIN	ON
14	21	5	TRIPLE	CU 0.1	MAIN	ON
14	15	1	TRIPLE	WAVE 95	MAIN	ON
15	16	6	TRIPLE	WAVE 95	MAIN	ON
16	17	28	TRIPLE	CU 0.06	MAIN	ON

Figure 6: Example of load input tab

							Phase Imbalance				
							Red (%)	Yellow (%)	Blue (%)		
Node	**Type**	**No of Consumers**	**Consumer Type**	**No of Phases**	**Phase Sequence**	**Balanced**	**Red (%)**	**Yellow (%)**	**Blue (%)**	**Annual Consumption (kWh)**	**Status**
68	BRANCH	12	GAPAB	TRIPLE	AUTO					1000	ON
70	BRANCH	3	GAPAB	TRIPLE	AUTO					1000	ON
14	BRANCH	4	GAPEB	TRIPLE	AUTO					1000	ON
13	BRANCH	2	GAPEB	TRIPLE	AUTO					1000	ON

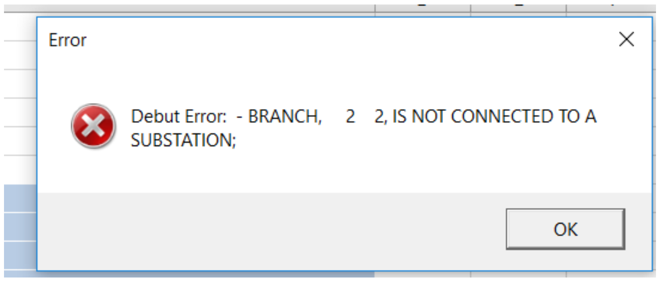
Figure 7: Resultant Network Topography



The location of the source transformer is depicted in the graphical network presentation as shown in Figure 7.

To allow users to debug any connectivity which they have input into the tool, there is functionality which guides the user to any errors which may have been introduced during loading of the model. This functionality is executed when the Network Model is compiled, and it will report the location of any instances of islanded nodes. An example of such a warning is shown in Figure 8.

Figure 8: Islanded Node Warning



5.3 Customer representation

The Network Model needs to be informed of where customers are connected. The Network Model allows the user to represent customers using two different strategies which are either a point load representation or a distribution branch representation.

Customer as a point load representation

In this case, each customer is placed upon a node that has already been declared within the Network Model. Figure 9 shows an example of point loads being declared in the Network Model and the data format is explained in Table 2.

Customers modelled as a point load can either be assigned to meet a global imbalance setting or alternatively can be assigned manually per row.

Figure 9: Example of point load input to the Network Model

							Phase Imbalance				
							Red (%)	Yellow (%)	Blue (%)		
Node	**Type**	**No of Consumers**	**Consumer Type**	**No of Phases**	**Phase Sequence**	**Balanced**	**Red (%)**	**Yellow (%)**	**Blue (%)**	**Annual Consumption (kWh)**	**Status**
1	POINT	16	GEPEB	TRIPLE	AUTO					3550	ON
2	POINT	9	GEPEB	TRIPLE	AUTO					3550	ON
3	POINT	4	GEPEB	TRIPLE	AUTO					3550	ON
4	POINT	3	GEPEB	TRIPLE	AUTO					3550	ON
5	POINT	2	OIB	TRIPLE	AUTO					5000	ON
6	POINT	1	GEPEB	TRIPLE	AUTO					3550	ON

Table 2: Point load data format

Attribute	Description
Near Node	The ID number of the node which the load representation is to be connected to
No of Customers	How many instances of this customer are connected to the "Near Node"
Customer Type	Refers to the load profile to be used. Load Profiles are discussed in section 3.3.2
No of Phases	Describes whether customers are connected across Ph- N, Ph to Ph or three phases.
Phase sequence	Normally set to auto but can allow different phase sequences to be modelled
Phase Imbalance	The global phase imbalance seeks to allocate 100% of the observed three phase demand across the phases. This will only work for customers declared as point loads
Annual Consumption (kWh)	Annual energy consumption of the customer being modelled
Status	Customer on load or off load

It should be noted that each point load entry allows the user to declare multiple, but identical, users to be connected at one node. If the user wishes to declare multiple customers with different energy characteristics, then a new entry per customer would need to be declared.

The point load representation allows each customer to have a different customer profile and annual energy consumption. This is at the cost of having to declare a node and service cable for each customer.

The allocation of customers to each LV feeder is controlled by the builder script which combines network data with census data to allocate customer types to the locations where customers are known to be located.

Within the backing store of the Network Model is a database which describes how many customers and of which customer type are connected to each feeder. This database is intended to be controlled by the administrator and not presented to the user. The database allows feeders to be allocated to primary substations and primary substations to be allocated into bulk supply point scale groups. This information is an output of the customer model as discussed in SDRC 2.3.

Distributed customer representation

In this case, identical customers can be spaced along an existing branch between existing nodes, at equal distances, without the need to first declare new nodes. This can be used to connect large quantities of customers without declaring a node for each service cable or without knowing exactly where customers are connected.

Table 1 describes the data format for the creation of branches and shows that the following three parameters can be populated during branch creation:

- Customer type
- Annual Consumption
- No of customers

Use of this representation allows the user to connect a large number of identical customers across an existing branch.

5.4 Interface with Customer Model

Within the backing store of the Network Model is a database that stores records from the Customer Model. These profiles express how customers use power over the day. The University of Southampton is responsible for the process which presents these load profiles via the Customer Model.

The outputs from the Customer Model will be a set of load profiles for types of customers groups that describe:

- Energy usage patterns under existing baseline conditions.
- Energy usage patterns following customer interventions
- The Network Model also allows the user to express the percentage uptake of Low Carbon Technologies (LCTs)

The model acknowledges that the observations of the difference in power consumption patterns between similar users will vary on a random basis. For this reason, the load profile for each customer group is defined in terms of:

- The mean average power consumption, per half hour period, across a group of similar customers. These groups of similar customers are referred to as customer types.
- The standard deviation per 30-minute period across a customer type.
- To enable 365 days per year analysis, each customer type will be modelled using a 30-minute resolution of the mean average power consumption and the standard deviation consumption for the following profiles: winter weekday, Saturday and Sunday, spring and autumn weekday, Saturday and Sunday and summer weekday and Saturday and Sunday.

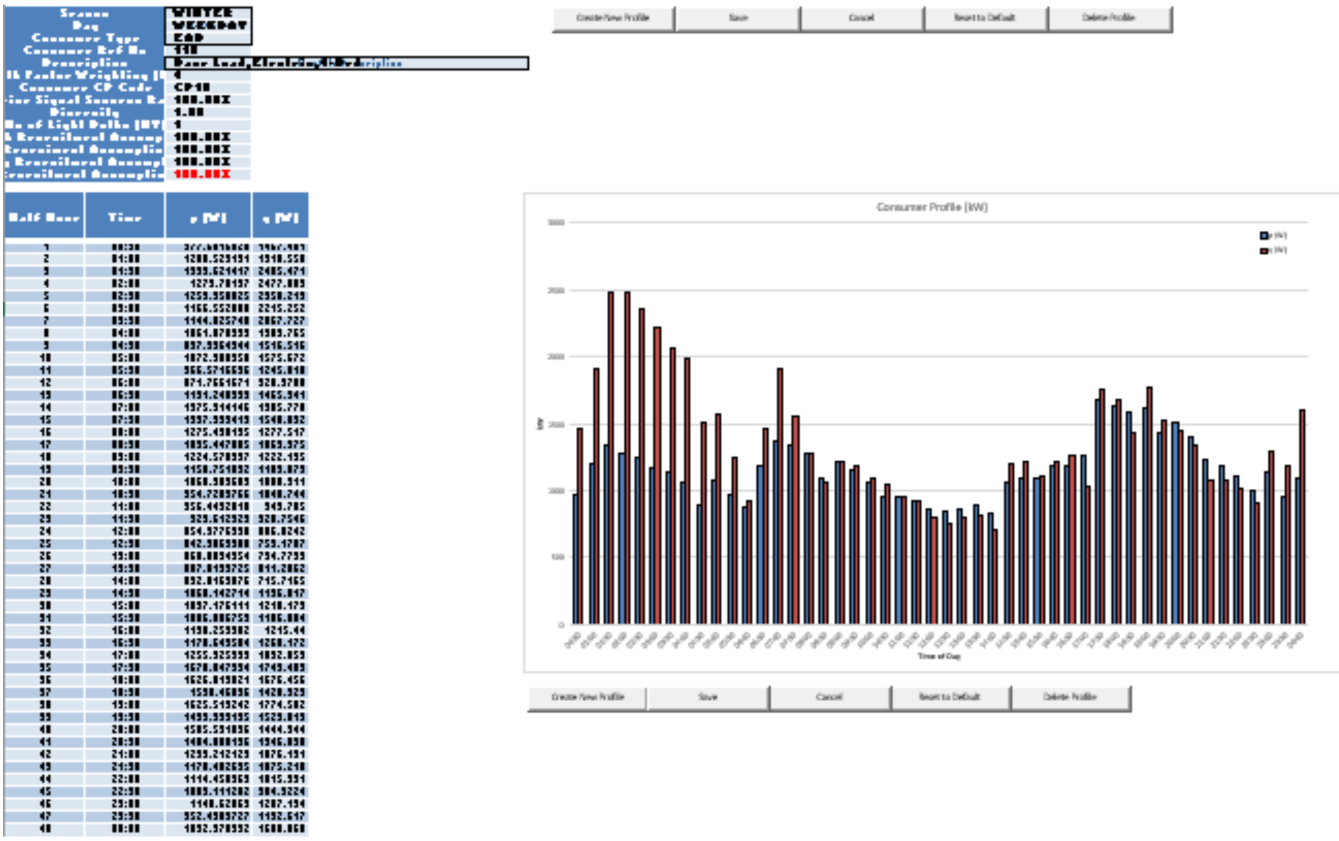
Customer information may be placed into the Network Model either by loading it into the backing store or by manually declaring a new customer and profile within the customer information parts of the environment.

Because the Customer Model also provides data on how the observed readings from similar customers will vary within a distribution, the Network Model can adopt a statistical view of network limits. This feature allows the DEBUT engine to calculate load flows based on the 90th percentile loading criteria which are in accordance with ACE 49 and simulate tapering diversity in the DEBUT engine.

This customer representation also allows the EGD part of the load flow engine to forecast the feeder loading per 30-minute period resolution based on the average demand per customer type and also take account of embedded generation.

Users are able to interact with the customer models kept within the backing store or even create new customer types via the consumer profiles tab of the environment which is shown in Figure 10.

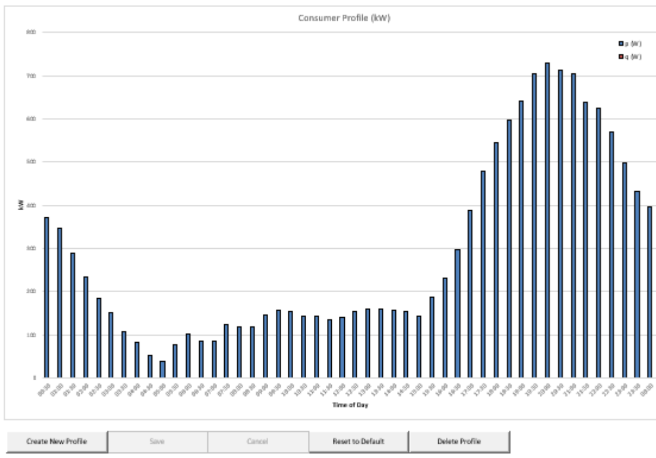
Figure 10: Example of Customer profile page within the Network Model



The Network Model represents the network year-round by using load profiles for each customer that relate to seasonal days (i.e. winter weekday, winter weekend, spring weekday and spring weekend etc). This means that each customer type must have a full set of seasonal load profiles created so it can be represented year-round.

LCT such as electric vehicles and heat pumps are also modelled via this tab and are used in forward looking studies such as the future assessment or the costing assessment tabs. Examples of these curves are shown in Figure 11.

Figure 11: Example of EV load profile



During the analysis of future growth scenarios, the Network Model will allocate LCT to be connected at locations along the feeder. The Network Model will decide the quantity and location of LCT in a manner that is decided by the assumptions that are selected with the load growth assumptions tab as discussed in section 5.7 and 6.

To enable the HV/EHV module to be able to study SAVE interventions as mitigation to HV or EHV constraints, the model needs to be able to aggregate the effect of these interventions to the scale of the constraint. To enable this the model maintains a database of:

- How many customers in total are connected to each HV feeder.
- Demographic information explaining how many of these customers relate to each customer type.
- Connectivity mapping of which HV feeders are connected to which primary substation.
- Connectivity mapping of which primary substations are connected to which bulk supply point.

Within the Consumer Profiles tab, users may amend the parameters summarised within Table 3 associated with each consumer.

Table 3: Point load data format

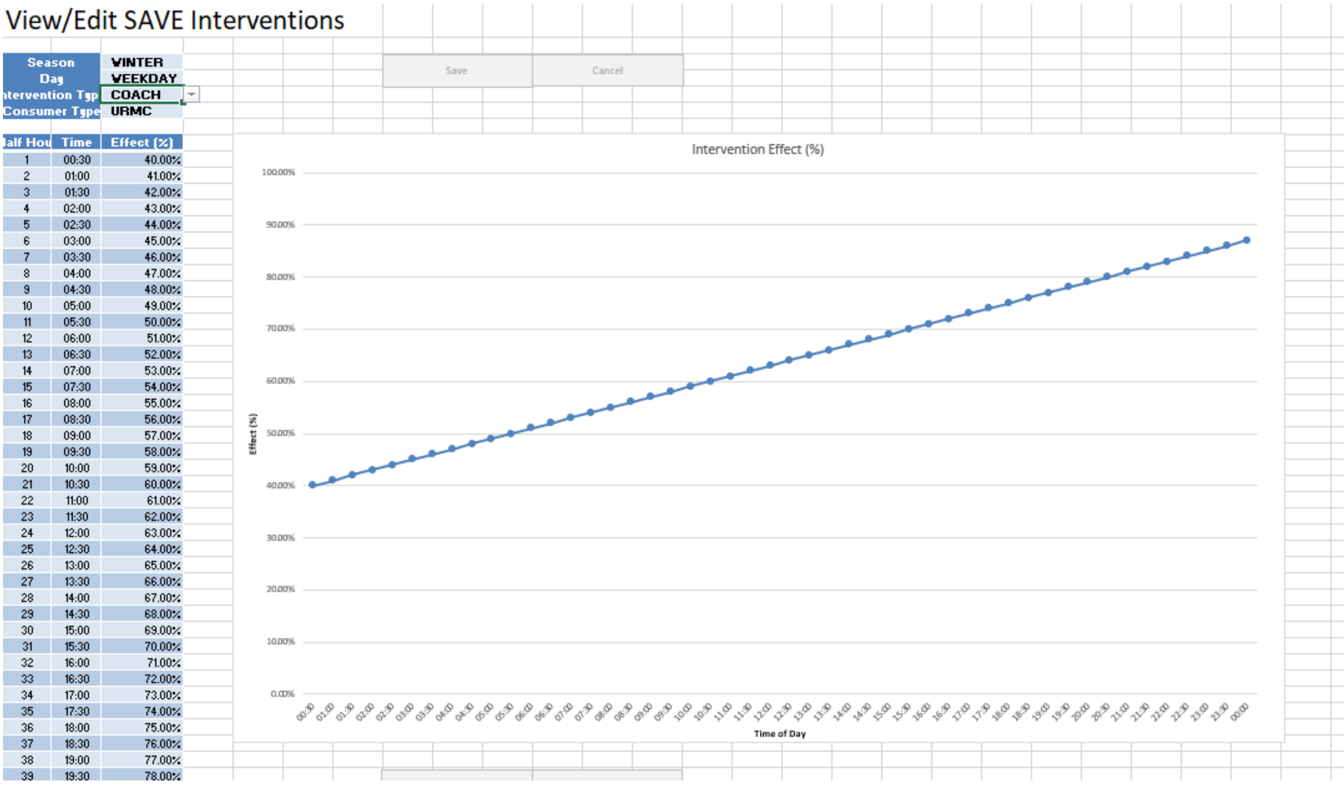
Attribute	Description
Season and Day	The season and day that the profile relates to
Consumer type	Description of the consumer type
Consumer reference number	The individual reference number for the profile
Description	Free text description of the model's purpose
Consumer CP code	Individual reference per consumer type
Price signal success rate	A signal between 0 and 100% used for the HV/EHV model to indicate how many of these customers respond to the price signal
Diversity	For use within the HV/EHV module to allow for any diversity in how individual users respond to the interventions. These figures may range between 0 and 1 where 1 assumes that all consumers respond simultaneously and equally
Lightbulb recruitment assumption	For use with the HV/EHV module to vary take-up assumptions for how many consumers within the maximum available take part in this intervention.
Data recruitment assumption	For use with the HV/EHV module to vary take-up assumptions for how many consumers within the maximum available take part in this intervention.
Coaching recruitment assumption	For use with the HV/EHV module to vary take-up assumptions for how many consumers within the maximum available take part in this intervention.
Price signal recruitment assumption	For use with the HV/EHV module to vary take-up assumptions for how many consumers within the maximum available take part in this intervention.

The backing store is kept locally on each installation and a loading script is provided that will enable updates of locally stored load profiles in line with administrator sanctioned changes to the customer profiles.

The effect of community coaching, data-led engagement and low energy lightbulb interventions are modelled by applying changes to the base caseload profiles within the time domain.

The effect of these three interventions on the consumer load profiles is held in the backing store, but users may interact with the model behind these interventions on the interventions tab as shown in Figure 12. On this tab, the amount of effect on the consumer profile that each intervention will have is modelled using data from the UoS analysis of SAVE project trial findings.

Figure 12: Example of intervention profile



Season	WINTER
Day	WEEKDAY
tervention Typ	COACH
Consumer Type	URMC

alf Hou	Time	Effect (%)
1	00:30	40.00%
2	01:00	41.00%
3	01:30	42.00%
4	02:00	43.00%
5	02:30	44.00%
6	03:00	45.00%
7	03:30	46.00%
8	04:00	47.00%
9	04:30	48.00%
10	05:00	49.00%
11	05:30	50.00%
12	06:00	51.00%
13	06:30	52.00%
14	07:00	53.00%
15	07:30	54.00%
16	08:00	55.00%
17	08:30	56.00%
18	09:00	57.00%
19	09:30	58.00%
20	10:00	59.00%
21	10:30	60.00%
22	11:00	61.00%
23	11:30	62.00%
24	12:00	63.00%
25	12:30	64.00%
26	13:00	65.00%
27	13:30	66.00%
28	14:00	67.00%
29	14:30	68.00%
30	15:00	69.00%
31	15:30	70.00%
32	16:00	71.00%
33	16:30	72.00%
34	17:00	73.00%
35	17:30	74.00%
36	18:00	75.00%
37	18:30	76.00%
38	19:00	77.00%
39	19:30	78.00%

Within this tab, it can be seen that there needs to be one profile per seasonal day and a value for the amount of effect that each intervention has on a half-hourly resolution.

The effect of price signals on load flows is modelled separately from this input tab and discussed in section 6.3.

5.5 Generator profiles

The Generator Profiles tab allows generation to be modelled on a half hour basis and also on a year-round basis. These profiles are held in the backing store, but users can interact with or create these profiles via the Generator Profiles tab.

Examples of the interface to these load curves are shown in Figure 13. These curves are used during analysis of LV networks. These profiles are applied where the generation has been declared in the base case model or when growth scenarios choose to apply new generation in future years. In these cases, new generators are declared within the model, in accordance with the LCT uptake growth assumptions that are specified by the user.

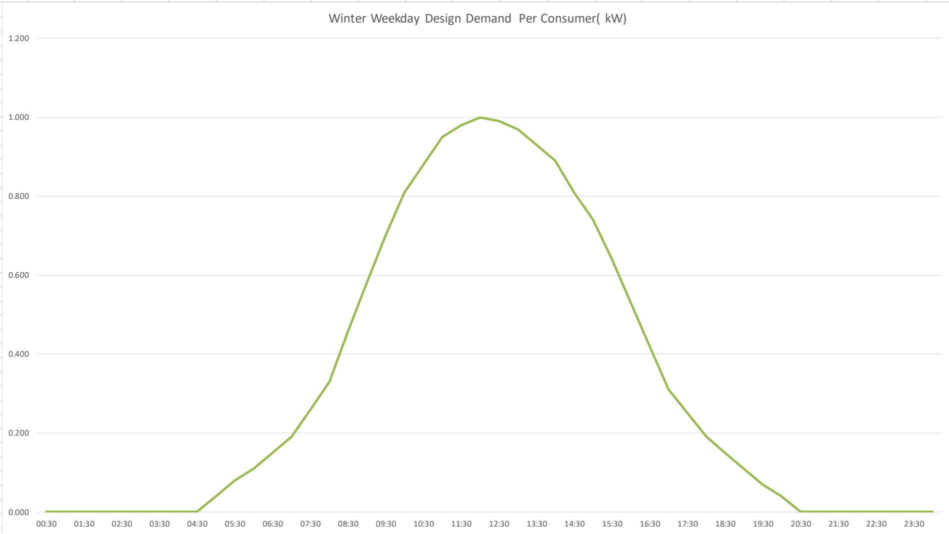
The output profile of these new installations is scaled up or down to meet any LCT size assumptions that have been stipulated by the user also.

Figure 13: Examples of Generator interface tab within the Network Model

Generator Type	PV

Save | Cancel | Reset to Default

Half Hou	Time	Day	p
1	00:30	Winter Weekday	0.000
2	01:00	Winter Weekday	0.000
3	01:30	Winter Weekday	0.000
4	02:00	Winter Weekday	0.000
5	02:30	Winter Weekday	0.000
6	03:00	Winter Weekday	0.000
7	03:30	Winter Weekday	0.000
8	04:00	Winter Weekday	0.000
9	04:30	Winter Weekday	0.000
10	05:00	Winter Weekday	0.040
11	05:30	Winter Weekday	0.080
12	06:00	Winter Weekday	0.110
13	06:30	Winter Weekday	0.150
14	07:00	Winter Weekday	0.190
15	07:30	Winter Weekday	0.260
16	08:00	Winter Weekday	0.330
17	08:30	Winter Weekday	0.460
18	09:00	Winter Weekday	0.580
19	09:30	Winter Weekday	0.700
20	10:00	Winter Weekday	0.810
21	10:30	Winter Weekday	0.880
22	11:00	Winter Weekday	0.950
23	11:30	Winter Weekday	0.980
24	12:00	Winter Weekday	1.000
25	12:30	Winter Weekday	0.990
26	13:00	Winter Weekday	0.970
27	13:30	Winter Weekday	0.930
28	14:00	Winter Weekday	0.890
29	14:30	Winter Weekday	0.810
30	15:00	Winter Weekday	0.740
31	15:30	Winter Weekday	0.640
32	16:00	Winter Weekday	0.530
33	16:30	Winter Weekday	0.420
34	17:00	Winter Weekday	0.310
35	17:30	Winter Weekday	0.250
36	18:00	Winter Weekday	0.190
37	18:30	Winter Weekday	0.150
38	19:00	Winter Weekday	0.110
39	19:30	Winter Weekday	0.070
40	20:00	Winter Weekday	0.040
41	20:30	Winter Weekday	0.000
42	21:00	Winter Weekday	0.000
43	21:30	Winter Weekday	0.000
44	22:00	Winter Weekday	0.000
45	22:30	Winter Weekday	0.000
46	23:00	Winter Weekday	0.000
47	23:30	Winter Weekday	0.000
48	00:00	Winter Weekday	0.000



Save | Cancel | Reset to Default

5.6 Single assessment

The single assessment function of the Network Model allows users to review the duty on a network, based on a specified season and type of day (typically winter weekday as the time of year network capacity is most likely to peak and when resultant SAVE interventions were run). This assessment is suited to studying base case conditions without any network development. An example of the input area for this study is shown in Figure 14.

Users may influence the amount of diversity implied by the standard deviation curves per customer type by altering the diversity weighting. Applying a weighting less than 100% would reduce the diversity assumed to be in the network.

Figure 14: Example of single assessment input

Study Options	DAY
Season	SPRING
Day	WEEKDAY
Diversity Weighting (Default 100%)	100%
Run Assessment	
Results Summary	
Last Run	19/03/2019 10:17
Debut Input Files	C:\Users\paul.morris\Documents\SAVE\SAVE Installation 20190318\assessments\I_SINGLE_ASSESSMEN
Debut Output Files	C:\Users\paul.morris\Documents\SAVE\SAVE Installation 20190318\assessments\O_SINGLE_ASSESSME

The Single Assessment tab provides an overview of the results presented on subsequent pages. An example of this overview is shown in Figure 15. This tab shows the maximum voltage drop along the feeder, the maximum voltage rise above nominal and a summary of any overloads.

Figure 15: Example of single assessment results overview

Max Tx Util (%)	91.18									
Tx Hours Over Rating	0									
	Volt						Current Overload			
Feeder Number	Max Drop (%)	Max Rise (%)	Lower Red	Lower Amber	Upper Amber	Upper Red	Max	Amber (m)	Red (m)	Longest (
1	7.5	0.00	122	0	0	0	8.3	0	0	0
2	1.8	0.00	0	0	0	0	0	0	0	0
3	5.6	0.00	43	53	0	0	0	0	0	0
4	3.7	0.00	0	4	0	0	0	0	0	0

The overview provides:

- The maximum transformer utilisation within the day including the number of hours the transformer is outside its rating (based on DEBUT rather than EGD analysis).
- For each feeder, the maximum feeder voltage drop, (based on DEBUT rather than EGD analysis).
- For each feeder, the distribution of customer criticality who are receiving voltages outside of tolerance.
- For each feeder, the length of each feeder where the circuit loading exceeds criticality limits.

This overview tab allows a high-level review of how congested a feeder is, but at an information resolution which talks generally about the entire feeder without explaining where the congestion is or how long it persists for.

To allow for more detailed analysis, there are more detailed branch and node level reports.

Figure 16: Example of Branch loading report from single analysis

			Phasing										
Feeder Number	Node	Number Of Consumers	Red	Yellow	Blue	Highest Voltage	Day of Highest Voltage	Season of Highest Voltage	Time of Highest Voltage	Lowest Voltage	Day of Lowest Voltage	Season of Lowest Voltage	Time of Lowest Voltage
1	11	0	0	0	0	232	WEEKDAY	WINTER	03:00:00	231.99	WEEKDAY	WINTER	18:00:00
1	14	4	2	1	1	231.44	WEEKDAY	WINTER	03:00:00	229.13	WEEKDAY	WINTER	18:00:00
1	12	0	0	0	0	232.14	WEEKDAY	WINTER	19:00:00	231.72	WEEKDAY	WINTER	19:00:00
1	13	2	0	1	1	232.14	WEEKDAY	WINTER	19:00:00	231.55	WEEKDAY	WINTER	19:00:00
1	21	0	0	0	0	231.44	WEEKDAY	WINTER	03:00:00	229.11	WEEKDAY	WINTER	18:00:00
1	15	0	0	0	0	231.44	WEEKDAY	WINTER	03:00:00	229.12	WEEKDAY	WINTER	18:00:00
1	16	1	1	0	0	231.41	WEEKDAY	WINTER	03:00:00	229.03	WEEKDAY	WINTER	18:00:00
1	17	0	0	0	0	231.26	WEEKDAY	WINTER	03:00:00	228.87	WEEKDAY	WINTER	18:00:00
1	20	4	1	2	1	231.23	WEEKDAY	WINTER	03:00:00	228.42	WEEKDAY	WINTER	18:00:00
1	18	0	0	0	0	231.23	WEEKDAY	WINTER	03:00:00	228.84	WEEKDAY	WINTER	18:00:00
1	19	4	1	1	2	231.19	WEEKDAY	WINTER	03:00:00	228.3	WEEKDAY	WINTER	18:00:00
1	22	3	1	1	1	231.42	WEEKDAY	WINTER	03:00:00	229.06	WEEKDAY	WINTER	18:00:00

Feeder Number	Node	Above Overvoltage Red Limit (Red Phase Hours)	Above Overvoltage Red Limit (Yellow Phase Hours)	Above Overvoltage Red Limit (Blue Phase Hours)	Within Overvoltage Amber Limit (Red Phase Hours)	Within Overvoltage Amber Limit (Yellow Phase Hours)	Within Overvoltage Amber Limit (Blue Phase Hours)	Within Nominal Green Band (Red Phase Hours)	Within Nominal Green Band (Yellow Phase Hours)	Within Nominal Green Band (Blue Phase Hours)	Within Undervoltage Amber Limit (Red Phase Hours)	Within Undervolta Amber Lim (Yellow Phase Hour
1	11	0	0	0	0	0	0	1564.29	1564.29	1564.29	0	0
1	14	0	0	0	0	0	0	1564.29	1564.29	1564.29	0	0
1	12	1564.29	0	0	0	0	0	0	1564.29	1564.29	0	0
1	13	1564.29	0	0	0	0	0	0	1564.29	1564.29	0	0
1	21	0	0	0	0	0	0	1564.29	1564.29	1564.29	0	0
1	15	0	0	0	0	0	0	1564.29	1564.29	1564.29	0	0
1	16	0	0	0	0	0	0	1564.29	1564.29	1564.29	0	0
1	17	0	0	0	0	0	0	1564.29	1564.29	1564.29	0	0
1	20	0	0	0	0	0	0	1564.29	1564.29	1564.29	0	0
1	18	0	0	0	0	0	0	1564.29	1564.29	1564.29	0	0
1	19	0	0	0	0	0	0	1564.29	1564.29	1564.29	0	0
1	22	0	0	0	0	0	0	1564.29	1564.29	1564.29	0	0

The branch loading report is shown in Figure 16. This report makes a one-row report for each branch in the model. The first 12 columns of the branch loading report confirm the construction details for each branch. The remaining columns of the report confirm the load flow results for each branch as follows:

- Value of maximum current load and the time and day upon which it occurred (as per DEBUT methodology)
- The amount of time that the loading of each branch resides within a criticality band. The criticality limits relate to the number of hours within the study that a branch resides within user-defined loading limits. These results are intended to allow users to decide which branches are most in need of attention.

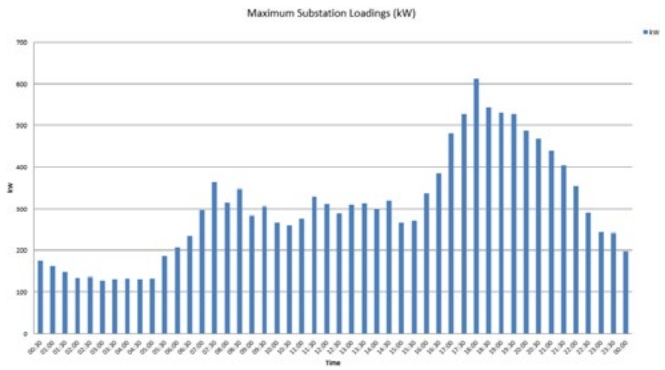
Figure 17: Example of voltage report from single analysis

			Phasing																					
Feeder Number	Node	Number Of Consumers	Red	Yellow	Blue	Highest Voltage	Day of Highest Voltage	Season of Highest Voltage	Time of Highest Voltage	Lowest Voltage	Day of Lowest Voltage	Season of Lowest Voltage	Time of Lowest Voltage	Above Overvoltage Red Limit (Red Phase Hours)	Above Overvoltage Red Limit (Yellow Phase Hours)	Above Overvoltage Red Limit (Blue Phase Hours)	Within Overvoltage Amber Limit (Red Phase Hours)	Within Overvoltage Amber Limit (Yellow Phase Hours)	Within Overvoltage Amber Limit (Blue Phase Hours)	Within Nominal Green Band (Red Phase Hours)	Within Nominal Green Band (Yellow Phase Hours)	Within Nominal Green Band (Blue Phase Hours)	Within Undervoltage Amber Limit (Red Phase Hours)	Within Undervolta Amber Lim (Yellow Phase Hour
1	11	0	0	0	0	232	WEEKDAY	WINTER	03:00:00	231.99	WEEKDAY	WINTER	18:00:00	0	0	0	0	0	0	1564.29	1564.29	1564.29	0	0
1	14	4	2	1	1	231.44	WEEKDAY	WINTER	03:00:00	229.13	WEEKDAY	WINTER	18:00:00	0	0	0	0	0	0	1564.29	1564.29	1564.29	0	0
1	12	0	0	0	0	232.14	WEEKDAY	WINTER	19:00:00	231.72	WEEKDAY	WINTER	19:00:00	1564.29	0	0	0	0	0	0	1564.29	1564.29	0	0
1	13	2	0	1	1	232.14	WEEKDAY	WINTER	19:00:00	231.55	WEEKDAY	WINTER	19:00:00	1564.29	0	0	0	0	0	0	1564.29	1564.29	0	0
1	21	0	0	0	0	231.44	WEEKDAY	WINTER	03:00:00	229.11	WEEKDAY	WINTER	18:00:00	0	0	0	0	0	0	1564.29	1564.29	1564.29	0	0
1	15	0	0	0	0	231.44	WEEKDAY	WINTER	03:00:00	229.12	WEEKDAY	WINTER	18:00:00	0	0	0	0	0	0	1564.29	1564.29	1564.29	0	0
1	16	1	1	0	0	231.41	WEEKDAY	WINTER	03:00:00	229.03	WEEKDAY	WINTER	18:00:00	0	0	0	0	0	0	1564.29	1564.29	1564.29	0	0
1	17	0	0	0	0	231.26	WEEKDAY	WINTER	03:00:00	228.87	WEEKDAY	WINTER	18:00:00	0	0	0	0	0	0	1564.29	1564.29	1564.29	0	0
1	20	4	1	2	1	231.23	WEEKDAY	WINTER	03:00:00	228.42	WEEKDAY	WINTER	18:00:00	0	0	0	0	0	0	1564.29	1564.29	1564.29	0	0
1	18	0	0	0	0	231.23	WEEKDAY	WINTER	03:00:00	228.84	WEEKDAY	WINTER	18:00:00	0	0	0	0	0	0	1564.29	1564.29	1564.29	0	0
1	19	4	1	1	2	231.19	WEEKDAY	WINTER	03:00:00	228.3	WEEKDAY	WINTER	18:00:00	0	0	0	0	0	0	1564.29	1564.29	1564.29	0	0
1	22	3	1	1	1	231.42	WEEKDAY	WINTER	03:00:00	229.06	WEEKDAY	WINTER	18:00:00	0	0	0	0	0	0	1564.29	1564.29	1564.29	0	0

The voltage results report is shown in Figure 17. This report makes a one-row report for each node in the model. The first 6 columns of the branch loading report confirm the construction details for each node. The remaining columns of the report confirm the load flow results for each branch as follows:

- Value of the highest voltage received at that node and the time day and season it was received. This value is received from the EGD load flow engine.
- Value of the lowest voltage received at that node and the time day and season it was received. This value is received from the DEBUT load flow engine.
- The remaining reporting cells explain for how many hours the node resided in user-defined criticality bandings.

Figure 18: Example of substation loading report for single analysis



The substation loading report provides a load versus time graph of the load upon the substation. The report also provides the results in tabular form. This analysis is driven by the DEBUT load flow engine. Because the report is published in Excel, users may apply conditional formatting to the results table to highlight results.

5.7 Future Assessment

The Future Assessment tab of the module allows users to study the technical effect of one single growth scenario. These growth scenarios can be either those specified by BEIS or custom growth assumptions set by the user. The control panel for this assessment is shown in Figure 19.

Figure 19: Future assessment modelling choices

Load Growth Rate (%)	2.00%
LCT Load Growth Probabilities	BEIS
PV Take Up Rate	High
HP Take Up Rate	Medium
EV Take Up Rate	Low
LCT Distribution Weighting	Near to Sub
Start Year	2058
End Year	2058
Winter Peak Only?	Yes
EV Charger size (VA)	6000
HP Size (Annual Consumption kWh)	4000
PV Size (kW)	5.5
Run Type	Without Intervention
Intervention	SAVE Interventions
Select SAVE Consumer Profile	LIGHTS
Year Applied	2039

The alterations that can be made to customer behaviour include:

- Background load growth rate (i.e. growth in consumption from non-low carbon technology devices)
- Parameters relating to the set of growth assumptions around take-up of LCT including which forecast to use, technology-specific take-up rates and general rules as to where the LCT should be assumed to be connecting in the future.
- The horizon of time that the study should cover

In addition to analysis of the base case network, the performance of the network following any one of the following interventions can also be studied:

- SAVE interventions (community coaching, data led engagement and low energy lightbulbs)
- Transformer uprating
- Overlaying the overloaded sections of the circuit with a higher rated construction
- Splitting of the feeder to create two new feeders from the original single feeder

This report allows a technical analysis of the different interventions. An example of how the Network Model provides a summary of this comparison is shown in Figure 20.

The summary tables describe for each feeder:

- The first year that a non-compliant voltage or loading condition is observed
- The maximum and minimum voltage on a feeder within the period
- The number of circuit nodes that have unacceptable voltages, classified into user-defined criticality bands
- The number of metres of a circuit that are overloaded, classified into criticality bands

In this particular case, it can be seen how a feeder overlay resolves a voltage problem on Feeder 1.

Figure 20: Comparison of intervention in future assessment

Without Intervention	Volt							Current Overload			
Feeder Number	Non Compliant Voltage First Year	Max Drop (%) Over Period	Max Rise(%) Over Period	Lower Red Over Period	Lower Amber Over Period	Upper Amber Over Period	Upper Red Over Period	Non Compliance Current First Year	Amber (m) Over Period	Red (m) Over Period	Longest (m) Over Period
1	2022	6.8	0.0000	451	29	0	0		0	0	0
2		1.6	0.0000	0	0	0	0		0	0	0
3	2022	4.3	0.0007	64	141	0	0		0	0	0
4	2022	7.1	0.0022	192	0	0	0		0	0	0
5		2.5	0.0004	0	0	0	0		0	0	0
6	2022	1.7	0.0149	0	0	16	16		0	0	0

With Intervention	Volt							Current Overload			
Feeder Number	Non Compliant Voltage First Year	Max Drop (%) Over Period	Max Rise(%) Over Period	Lower Red Over Period	Lower Amber Over Period	Upper Amber Over Period	Upper Red Over Period	Non Compliance Current First Year	Amber (m) Over Period	Red (m) Over Period	Longest (m) Over Period
1		2.2	0.0000	0	0	0	0		0	0	0
2		1.6	0.0000	0	0	0	0		0	0	0
3	2022	4.3	0.0007	64	141	0	0		0	0	0
4	2022	7.1	0.0022	192	0	0	0		0	0	0
5		2.5	0.0004	0	0	0	0		0	0	0
6	2022	1.7	0.0149	0	0	16	16		0	0	0

The full reports can be found under the tabs labelled as Future Assessment Results and Future Intervention Results, as shown in Figure 21 and Figure 22.

Figure 21: Future Assessment full results

Assessment Results (No Intervention)

Voltage										Thermal									
Max Volt Drop					Max Volt Rise					Max Cable Utilisation						Max Transformer Utilisation			
Volt Drop (%)	Volt Drop Node	Volt Drop Time	Volt Drop Day	Volt Drop Season	Volt Rise (%)	Volt Rise Node	Volt Rise Time	Volt Rise Day	Volt Rise Season	Max Utilisation (%)	Near Node	Far Node	Cable Utilisation Time	Cable Utilisation Day	Cable Utilisation Season	Max Tx Utilisation (%)	Tx Utilisation Time	Tx Utilisation Day	Tx Utilisation Season
1.6	19	18:00:00	WEEKDAY	WINTER	0.06	12	19:00:00	WEEKDAY	WINTER	19.3	11	14	18:00:00	WEEKDAY	WINTER	5.7	18:00:00	WEEKDAY	WINTER
1.6	19	18:00:00	WEEKDAY	WINTER	0.06	12	19:00:00	WEEKDAY	WINTER	19.3	11	14	18:00:00	WEEKDAY	WINTER	5.7	18:00:00	WEEKDAY	WINTER
1.6	19	18:00:00	WEEKDAY	WINTER	0.06	12	19:00:00	WEEKDAY	WINTER	19.4	11	14	18:00:00	WEEKDAY	WINTER	5.72	18:00:00	WEEKDAY	WINTER
1.6	19	18:00:00	WEEKDAY	WINTER	0.06	12	19:00:00	WEEKDAY	WINTER	19.4	11	14	18:00:00	WEEKDAY	WINTER	5.72	18:00:00	WEEKDAY	WINTER
1.6	19	18:00:00	WEEKDAY	WINTER	0.06	12	19:00:00	WEEKDAY	WINTER	19.4	11	14	18:00:00	WEEKDAY	WINTER	5.74	18:00:00	WEEKDAY	WINTER
1.6	19	18:00:00	WEEKDAY	WINTER	0.06	12	19:00:00	WEEKDAY	WINTER	19.5	11	14	18:00:00	WEEKDAY	WINTER	5.74	18:00:00	WEEKDAY	WINTER
1.6	19	18:00:00	WEEKDAY	WINTER	0.06	12	19:00:00	WEEKDAY	WINTER	19.5	11	14	18:00:00	WEEKDAY	WINTER	5.76	18:00:00	WEEKDAY	WINTER
1.6	19	18:00:00	WEEKDAY	WINTER	0.06	12	19:00:00	WEEKDAY	WINTER	19.5	11	14	18:00:00	WEEKDAY	WINTER	5.76	18:00:00	WEEKDAY	WINTER
1.6	19	18:00:00	WEEKDAY	WINTER	0.06	12	19:00:00	WEEKDAY	WINTER	19.6	11	14	18:00:00	WEEKDAY	WINTER	5.78	18:00:00	WEEKDAY	WINTER
1.6	19	18:00:00	WEEKDAY	WINTER	0.06	12	19:00:00	WEEKDAY	WINTER	19.6	11	14	18:00:00	WEEKDAY	WINTER	5.78	18:00:00	WEEKDAY	WINTER
1.6	19	18:00:00	WEEKDAY	WINTER	0.06	12	19:00:00	WEEKDAY	WINTER	19.6	11	14	18:00:00	WEEKDAY	WINTER	5.8	18:00:00	WEEKDAY	WINTER
1.6	19	18:00:00	WEEKDAY	WINTER	0.06	12	19:00:00	WEEKDAY	WINTER	19.7	11	14	18:00:00	WEEKDAY	WINTER	5.82	18:00:00	WEEKDAY	WINTER
1.6	19	18:00:00	WEEKDAY	WINTER	0.06	12	19:00:00	WEEKDAY	WINTER	19.7	11	14	18:00:00	WEEKDAY	WINTER	5.82	18:00:00	WEEKDAY	WINTER
1.6	19	18:00:00	WEEKDAY	WINTER	0.06	12	19:00:00	WEEKDAY	WINTER	19.7	11	14	18:00:00	WEEKDAY	WINTER	5.84	18:00:00	WEEKDAY	WINTER
1.6	19	18:00:00	WEEKDAY	WINTER	0.06	12	19:00:00	WEEKDAY	WINTER	19.8	11	14	18:00:00	WEEKDAY	WINTER	5.84	18:00:00	WEEKDAY	WINTER
1.6	20	18:00:00	WEEKDAY	WINTER	0.06	12	19:00:00	WEEKDAY	WINTER	19.8	11	14	18:00:00	WEEKDAY	WINTER	5.86	18:00:00	WEEKDAY	WINTER
1.6	20	18:00:00	WEEKDAY	WINTER	0.06	12	19:00:00	WEEKDAY	WINTER	19.8	11	14	18:00:00	WEEKDAY	WINTER	5.86	18:00:00	WEEKDAY	WINTER
1.6	20	18:00:00	WEEKDAY	WINTER	0.06	12	19:00:00	WEEKDAY	WINTER	19.9	11	14	18:00:00	WEEKDAY	WINTER	5.88	18:00:00	WEEKDAY	WINTER
1.6	20	18:00:00	WEEKDAY	WINTER	0.06	12	19:00:00	WEEKDAY	WINTER	19.9	11	14	18:00:00	WEEKDAY	WINTER	5.88	18:00:00	WEEKDAY	WINTER
1.7	19	18:00:00	WEEKDAY	WINTER	0.06	12	19:00:00	WEEKDAY	WINTER	19.9	11	14	18:00:00	WEEKDAY	WINTER	5.9	18:00:00	WEEKDAY	WINTER
1.7	19	18:00:00	WEEKDAY	WINTER	0.06	12	19:00:00	WEEKDAY	WINTER	20	11	14	18:00:00	WEEKDAY	WINTER	5.9	18:00:00	WEEKDAY	WINTER
1.7	19	18:00:00	WEEKDAY	WINTER	0.06	12	19:00:00	WEEKDAY	WINTER	20	11	14	18:00:00	WEEKDAY	WINTER	5.92	18:00:00	WEEKDAY	WINTER
1.7	19	18:00:00	WEEKDAY	WINTER	0.06	12	19:00:00	WEEKDAY	WINTER	20.1	11	14	18:00:00	WEEKDAY	WINTER	5.94	18:00:00	WEEKDAY	WINTER

Figure 21 describes the effect of network growth on compliance and repeats the observations already defined in the summary table, but on an annual basis. This table does not consider the effect of any interventions.

Figure 22: Future Intervention full results

Future Assessment Results (Feeder Replacement)																				
	Voltage										Thermal									
	Max Volt Drop					Max Volt Rise					Max Cable Utilisation						Max Transformer Utilisation			
Year	Volt Drop (%)	Volt Drop Node	Volt Drop Time	Volt Drop Day	Volt Drop Season	Volt Rise (%)	Volt Rise Node	Volt Rise Time	Volt Rise Day	Volt Rise Season	Max Utilisation (%)	Near Node	Far Node	Cable Utilisation Time	Cable Utilisation Day	Cable Utilisation Season	Max Tx Utilisation (%)	Tx Utilisation Time	Tx Utilisation Day	Tx Utilisation Season
2026	0.6	20	18:00:00	WEEKDAY	WINTER	0.04	12	19:00:00	WEEKDAY	WINTER	8.6	100	11	18:00:00	WEEKDAY	WINTER	5.7	18:00:00	WEEKDAY	WINTER
2027	0.6	20	18:00:00	WEEKDAY	WINTER	0.04	12	19:00:00	WEEKDAY	WINTER	8.6	100	11	18:00:00	WEEKDAY	WINTER	5.7	18:00:00	WEEKDAY	WINTER
2028	0.6	20	18:00:00	WEEKDAY	WINTER	0.04	12	19:00:00	WEEKDAY	WINTER	8.6	100	11	18:00:00	WEEKDAY	WINTER	5.72	18:00:00	WEEKDAY	WINTER
2029	0.6	20	18:00:00	WEEKDAY	WINTER	0.04	12	19:00:00	WEEKDAY	WINTER	8.7	100	11	18:00:00	WEEKDAY	WINTER	5.72	18:00:00	WEEKDAY	WINTER
2030	0.6	20	18:00:00	WEEKDAY	WINTER	0.04	12	19:00:00	WEEKDAY	WINTER	8.7	100	11	18:00:00	WEEKDAY	WINTER	5.74	18:00:00	WEEKDAY	WINTER
2031	0.6	20	18:00:00	WEEKDAY	WINTER	0.04	12	19:00:00	WEEKDAY	WINTER	8.7	100	11	18:00:00	WEEKDAY	WINTER	5.74	18:00:00	WEEKDAY	WINTER
2032	0.6	20	18:00:00	WEEKDAY	WINTER	0.04	12	19:00:00	WEEKDAY	WINTER	8.7	100	11	18:00:00	WEEKDAY	WINTER	5.76	18:00:00	WEEKDAY	WINTER
2033	0.6	20	18:00:00	WEEKDAY	WINTER	0.04	12	19:00:00	WEEKDAY	WINTER	8.7	100	11	18:00:00	WEEKDAY	WINTER	5.76	18:00:00	WEEKDAY	WINTER
2034	0.6	20	18:00:00	WEEKDAY	WINTER	0.04	12	19:00:00	WEEKDAY	WINTER	8.7	100	11	18:00:00	WEEKDAY	WINTER	5.78	18:00:00	WEEKDAY	WINTER
2035	0.6	20	18:00:00	WEEKDAY	WINTER	0.04	12	19:00:00	WEEKDAY	WINTER	8.8	100	11	18:00:00	WEEKDAY	WINTER	5.78	18:00:00	WEEKDAY	WINTER
2036	0.6	20	18:00:00	WEEKDAY	WINTER	0.04	12	19:00:00	WEEKDAY	WINTER	8.8	100	11	18:00:00	WEEKDAY	WINTER	5.8	18:00:00	WEEKDAY	WINTER
2037	0.6	20	18:00:00	WEEKDAY	WINTER	0.04	12	19:00:00	WEEKDAY	WINTER	8.8	100	11	18:00:00	WEEKDAY	WINTER	5.82	18:00:00	WEEKDAY	WINTER
2038	0.6	20	18:00:00	WEEKDAY	WINTER	0.04	12	19:00:00	WEEKDAY	WINTER	8.8	100	11	18:00:00	WEEKDAY	WINTER	5.82	18:00:00	WEEKDAY	WINTER
2039	0.6	20	18:00:00	WEEKDAY	WINTER	0.04	12	19:00:00	WEEKDAY	WINTER	8.8	100	11	18:00:00	WEEKDAY	WINTER	5.84	18:00:00	WEEKDAY	WINTER
2040	0.6	20	18:00:00	WEEKDAY	WINTER	0.04	12	19:00:00	WEEKDAY	WINTER	8.8	100	11	18:00:00	WEEKDAY	WINTER	5.84	18:00:00	WEEKDAY	WINTER
2041	0.6	20	18:00:00	WEEKDAY	WINTER	0.04	12	19:00:00	WEEKDAY	WINTER	8.9	100	11	18:00:00	WEEKDAY	WINTER	5.86	18:00:00	WEEKDAY	WINTER
2042	0.6	20	18:00:00	WEEKDAY	WINTER	0.04	12	19:00:00	WEEKDAY	WINTER	8.9	100	11	18:00:00	WEEKDAY	WINTER	5.86	18:00:00	WEEKDAY	WINTER
2043	0.6	20	18:00:00	WEEKDAY	WINTER	0.04	12	19:00:00	WEEKDAY	WINTER	8.9	100	11	18:00:00	WEEKDAY	WINTER	5.88	18:00:00	WEEKDAY	WINTER
2044	0.6	20	18:00:00	WEEKDAY	WINTER	0.04	12	19:00:00	WEEKDAY	WINTER	8.9	100	11	18:00:00	WEEKDAY	WINTER	5.88	18:00:00	WEEKDAY	WINTER
2045	0.6	20	18:00:00	WEEKDAY	WINTER	0.04	12	19:00:00	WEEKDAY	WINTER	8.9	100	11	18:00:00	WEEKDAY	WINTER	5.9	18:00:00	WEEKDAY	WINTER
2046	0.6	20	18:00:00	WEEKDAY	WINTER	0.04	12	19:00:00	WEEKDAY	WINTER	8.9	100	11	18:00:00	WEEKDAY	WINTER	5.9	18:00:00	WEEKDAY	WINTER
2047	0.6	20	18:00:00	WEEKDAY	WINTER	0.04	12	19:00:00	WEEKDAY	WINTER	9	100	11	18:00:00	WEEKDAY	WINTER	5.92	18:00:00	WEEKDAY	WINTER
2048	0.6	20	18:00:00	WEEKDAY	WINTER	0.04	12	19:00:00	WEEKDAY	WINTER	9	100	11	18:00:00	WEEKDAY	WINTER	5.94	18:00:00	WEEKDAY	WINTER

Figure 22 describes the effect of network growth on compliance and repeats the format of the observation already declared in the summary table, but on an annual basis, but with the assumption that the nominated network intervention has been deployed.

6

PRICING MODEL

This section describes the output tabs for functionality that is considered to be related to capital intervention pricing and pricing signals.

As already shown in section 3, the Pricing Model is able to receive inputs from the Network Model and the Customer Model.

When undertaking studies related to the LV network, the Pricing Model can test the performance of LV capacity investments by testing changes to the structure of the Network Model and seeing how long the capacity intervention in question has mitigated network issues for. These tests can be applied year-round.

When undertaking studies related to the HV network, the Pricing Model can compare the impact of SAVE related customer interventions upon the amount of potential overload observed at a constrained point in the network. This test can be conducted under winter peak conditions only.

The pricing and incentive tabs relate to the areas referred to as the Multi-Scenario, Economic Assessment and the HV/EHV Module in Figure 2

6.1 Multi-Scenario

The purpose of this report is to understand the best way to manage an LV secondary network across different growth scenarios, by investigating which capacity interventions are best selected when, and what is the cheapest or least risk approach to take.

The LV multi-scenario analysis is supported by 6 tabs within the overall module.

6.1.1 Cost Assumptions

The Costing Assumptions tab allows users to record cost assumptions to be used in the economic analysis is shown in Figure 23. This data is stored in the backing store and does not need to be updated for every study.

Figure 23: Cost assumptions for LV Multi-scenario

Transformer Uprate

Size (KVA)	Fixed Capex	Fixed Opex
200	3921.00	5000.00
300	4811.00	5250.00
315	4811.00	5500.00
500	6181.00	6000.00
750	8084.00	6000.00
800	8084.00	6000.00
1000	18933.00	5000.00

Save Cancel

SAVE Interventions

Code	Intervention	Fixed Capex	Fixed Opex	Variable Capex (Per 1000 Customers)	Variable Opex (Per Customer)
COACH	Community Coaching	250.00	150.00	20.00	0.06

Code	Intervention	Fixed Capex	Fixed Opex	Variable Capex (Per Customer)	Variable Opex (Per Customer)
ENGAGE	Data Led Engagement	250.00	150.00	0.02	0.06

Code	Intervention	Fixed Capex	Fixed Opex	Variable Capex	Variable Opex	Variable Lightbulb Opex
LIGHTS	Low Energy Lightbulbs	2000.00	150.00	0.02	0.07	0.50

Transformers can be modelled as having a different basic cost for installation and also a mobilisation fixed cost for installation. SAVE interventions can be modelled in terms of a number of fixed or variable CAPEX and OPEX headings.

6.1.2 Use of Scenarios

Recognising that it can be problematic to commit to a single growth forecast, the LV multi-scenario environment allows up to four growth scenarios to be studied. A design choice was made to limit the number of scenarios that could be studied simultaneously to four to avoid excessive computation time.

Figure 24: Declaration of growth scenarios in LV network multi-scenario analysis.

Start Year	2019
End Year	2042
Interest Rate	8.00%
Number of Scenarios	4
PV Size (kW - Default)	3.5
HP Size (kWh - Default)	4000
EV Charger Size (VA - Default)	6000
Network Design Year	2021
Winter Peak Only?	Yes

Scenario		Load Growth					LCT Distribution			
Number	Name	Rate (%)	LCT Probabilities	PV Take Up	HP Take Up	EV Take Up	Weighting	PV Size	HP Size	EV Size
1	High	5.00%	BEIS	Low	High	High	Far from Sub	5.5	4000	6000
2	Even Spread	1.00%	Custom	Medium	High	Medium	Even Distribution			
3	Distant	1.30%	Custom	High	Medium	Low	Far from Sub	4	3200	4500
4	Low Growth	1.35%	BEIS	Low	Low	Low	Even Distribution			

The scenarios can be set up in the manner shown in Figure 24. Each scenario may be defined with its own characteristics or alternatively take on the global settings defined at the top of the page.

The global parameters which apply to this study are:

- The start and end years which define the beginning and end of the study.
- The investment interest rate.
- The number of scenarios to be studied, which must be an integer between 1 and 4.
- Default options for the size of PV, HP and EV. These default options will be overwritten by any assumptions made per scenario.
- The network design year. The design year represents a point in the future which expresses the point in the future time horizon where each capital invention is expected to mitigate all predicted overloads up to[4].
- Whether the future of the network is to be studied under winter seasons only or all seasons.

Each growth scenario can then be defined by these parameters.

- Name, which is a user-configurable field allowing the scenario to be named.
- Load Growth, which represents the growth in electrical consumption of non-LCT devices.
- LCT probabilities, which defines whether to use the BEIS defined LCT take-up rates or those specified on the custom page.
- LCT Take up rate which prescribes which range of take-up probabilities from the LCT probabilities page is to be used i.e. low, medium or high for EV, PV and Heat Pumps.
- LCT distribution weighting which allows users to weight where LCT technologies are connected to the LV feeder. The possible fields are: Near to the source substation, even weighting along the feeder or, far from the source substation. This allows the user to manage the uncertainty of where the LCT will be connected.
- EV Size (Annual consumption in kVA). Which allows the user to state one assumption for the size of the Electric Vehicle chargers. The volume of EV chargers installed within the network is decided by the choice of LCT growth assumption and by whether the High, Medium or Low range growth assumption was selected.
- HP Size (Annual consumption in kWh) which allows the user to state one assumption regarding the annual energy consumption of heat pumps that are connected into customer premises. The volume of heat pumps installed within the network is decided by the choice of LCT growth assumption and by whether the High, Medium or Low range growth assumption was selected.
- PV Size (kW)which allows the user to state one assumption regarding the size of PV installations. The volume of PV installed within the network is decided by the choice of LCT growth assumption and by whether the High, Medium or Low range growth assumption was selected.

4 The network design year helps users control the number of visits to a feeder for mitigation that is required. A network design year in the near future reduces the risk of stranded assets but may require repeated mobilisation of projects that conduct reinforcement on different parts of a feeder.

6.1.3 Use of the Multi-Scenario report

When the pricing model detects that a branch has run out of capacity it will investigate what intervention is best deployed to manage said constraint. The rules guiding the sequence of management techniques are known as an investment strategy.

To reflect the fact that there are different approaches to timing capacity interventions, the multi-scenario tool enables an analysis of different sets of investment rules which are referred to as investment strategies

Regardless of the investment strategy, the tool will always react to an overloaded branch by recommending management in the year of a new overload occurring. To enable an economic analysis to take place, each reinforcement uses costing rules and the cost of each reinforcement is logged in the year of occurrence. Each investment strategy is therefore described as not only a sequence of interventions but also the years which they are called for and the net present value (NPV) of each sequence of interventions to enable comparison.

Because the optimum investment strategy changes depending on the user's attitude to the risk, the ability to mobilise non-network solutions and capacity for delivery of reinforcement schemes; the pricing model allows users to consider the effect of applying three different investment strategies, which are defined as follows:

All-knowing Strategy

The "all-knowing" strategy represents a strategy which considers the use of the following interventions:

- Overlay of an LV feeder
- Feeder splitting
- Transformer uprating
- Low energy lightbulbs
- Data led engagement
- Community coaching
- Price signals

The all-knowing strategy recommends the intervention sequence that gives the minimum cost works to deliver sufficient capacity at year 40 and instigates that scheme in the year of the first observed overload on a feeder or transformer.

The cheapest solution or sequence is identified by firstly understanding whether the network becomes overloaded in the study and then by identifying the first year in which branches become overloaded.

Each possible intervention is then tested to see if creates sufficient new capacity to last until the end of the planning horizon. Where a single physical intervention is not sufficient, it may be paired with additional interventions to provide a compliant solution. The cheapest solutions set is then isolated as the minimum cost scheme.

Once the capital intervention step has been undertaken, each of the SAVE intervention models is tested to see if they are able to resolve overloads, and for how many years they can defer LV reinforcements for. This is achieved by modelling each SAVE intervention in the Network Model. The effect of the SAVE interventions is modelled by using the customer profiles and intervention profiles to change each customer profile and then re-running the Network Model.

If a SAVE intervention is proven to be technically viable, it is then subject to an economic test to decide whether investing in the SAVE intervention followed by the cheapest capital intervention promotes a cheaper strategy on the basis of net present value.

The economic test of whether a SAVE intervention creates value is to assess whether the annual cost of a SAVE intervention is less than the interest earnt on the net present value of the capital intervention strategy. The interest rate used for this calculation is as per the value specified in Figure 24.

Where SAVE interventions are shown to be economic then they are instigated across the secondary substation in the year of the first observed overload, as a means to defer the planning capital interventions. Subsequent capital interventions are then triggered in the year that load growth overtakes the effect of the SAVE interventions.

The approach to the costing of each individual intervention is recorded in Appendix I.

It should be noted that SAVE interventions are not expected to resolve spring, summer or autumn import overloads or any overloads driven by export. For this reason, SAVE interventions are automatically discounted from resolving these issues. This approach also considers that the minimum deployment resolution of SAVE interventions is one secondary substation and that one SAVE intervention may be used to defer a reinforcement rather than stacked SAVE interventions.

Flexibility Minimum

The flexibility minimum strategy represents a strategy which considers the use of the following interventions:

- Incremental overlay of an LV feeder
- Feeder splitting
- Transformer uprating

This strategy is analogous to the traditional approach to network management where only network led solutions are available.

This strategy calculates an abutting sequence of capacity interventions to span up to 40 years, but it makes use of a concept known as the network design date.

The network design date concept replicates good investment practice by seeking to resolve as many network problems into one intervention to avoid repeated visits to uprate different parts of a feeder over time.

By specifying a network design date which is in the near future, the model resolves all overloads observed up to the design date in the year of the first overload and then take an incremental approach to resolve overloads after the design date.

Use of the network design date allows the user to strike a balance between the risk of stranding assets against the wasted cost of sequential mobilisations, for reinforcement projects on the same feeder.

The cheapest intervention sequence is resolved by firstly understanding whether the network becomes overloaded without any interventions and when.

Each possible intervention is then tested to see if it creates sufficient new capacity to last until the network design date which has been specified by the user.

The minimum intervention to meet the network design date is then added to the Network Model and the years between the network design date and the end of the planning horizon are studied to detect in which years new and additional overloads occur. Each new overload is then mitigated with the minimum cost capital scheme and the year in which it was required is recorded.

Once the capital intervention step has been undertaken, each of the SAVE interventions models introduced in 5.7 is tested to see if they are able to resolve overloads and for how many years they can defer LV reinforcements.

This is done by modelling each SAVE intervention within the Network Model. The effect of the SAVE interventions is modelled by using the customer profiles and intervention profiles to change each customer profile and then re-running the Network Model. The number of years that a SAVE intervention can mitigate overloads across the entire substation for is then noted. The annual cost of SAVE interventions is then assessed to be the cost of the SAVE intervention divided by the number of years of deferred reinforcements that it delivers.

The economic test of whether a SAVE intervention creates value is to assess whether the annual cost of a SAVE intervention is less than the interest earnt on the net present value of the capital intervention strategy. The interest rate used for this calculation is as per the value specified in Figure 24.

Where SAVE interventions are shown to be economic then they are instigated across the secondary substation in the year of the first observed overload as a means to defer the planned capital interventions. Subsequent capital interventions are then triggered in the year that load growth overtakes the effect of the SAVE interventions

The approach to the costing of each individual intervention is recorded in Appendix I.

Flexibility Maximum Strategy.

The flexibility maximum strategy represents a strategy which considers the use of the following interventions:

- Incremental overlay of an LV feeder
- Feeder splitting
- Transformer uprating
- Data led engagement
- Community Coaching
- Price Signals

This strategy follows the traditional approach to network management insofar as capacity intervention schemes are only required to create capacity within a credible investment horizon (known as the network design date), but also assesses the cost of capacity interventions to the end of the planning study.

Unlike Flexibility minimum, this strategy allows non-network solutions to be used which allows further optionality value to be explored. This strategy using the same approach to the calculation of an abutting sequence of interventions as Flexibility minimum but with the assumption that SAVE interventions are only deployed ahead of capital interventions and also with the same assumptions regarding the application of SAVE interventions as the all-knowing strategy. Once the capital intervention step has been undertaken, each of the SAVE interventions models introduced in 5.7 is tested to see if they are able to resolve overloads and for how many years they can defer LV reinforcements.

This is done by modelling each SAVE intervention within the Network Model. The effect of the SAVE interventions is modelled by using the customer profiles and intervention profiles to change each customer profile and then re-running the Network Model.

When a SAVE intervention is judged to be technically effective, it is then tested economically to understand whether using it to defer subsequent physical intervention is cheaper on a net present value basis.

Where SAVE interventions are shown to be economic then they are instigated across the secondary substation in the year of the first observed overload as a means to defer the planned capital interventions. Subsequent capital interventions are then triggered in the year that load growth overtakes the effect of the SAVE interventions

Each of these three investment strategies will result in a different total net present cost of managing a given network constraint. This cost will vary depending on the growth scenario under consideration.

It is the purpose of the Multi-scenario report, to calculate the net present value of each of these investment strategies against different LCT growth scenarios. This calculation allows users to understand the cheapest means of managing the network for each growth scenario.

Each of these strategies is tested automatically and the user can compare the results instead of having to choose a strategy. By using the regret table as depicted in Figure 26, users can understand what the most advantageous investment strategy to follow is and then look up the sequence of interventions associated with that strategy.

In this context, investment regret simulates the difference in cost of following one investment strategy in comparison to another. These costs will change depending on the growth scenario being considered. Because users are rarely in a position to be certain how the network will change over time, the investigation into the resultant investment regret, per investment strategy across the range of growth scenarios enables users to decide which investment strategy is best at limiting investment regret.

Once a user understands the optimum investment strategy, users can work out what capacity interventions need to be commissioned by when, through reviewing what is the first intervention recommended by the investment strategy for each scenario. This list of first interventions in effect becomes a watch list for the substation and by tracking the growth in LCT that is actually installed on the substation, the user can become confident in what capacity interventions they need to commission by when.

An example of the output from the multi-scenario analysis is shown in Figure 25. For each of the four growth scenarios and three investment strategies. The sequence of interventions required to avoid unacceptable loading on circuits or transformers across the substation are then listed in terms of the year they are required, the actual cost of the intervention, and the net present value of all capacity interventions across the substation and feeders.

This report shows for each growth scenario, what is the most favourable starting intervention and when it is required. When there is agreement across all scenarios as to what the most favourable starting intervention is, then that is a clear signal to the user as to what the least risky investment is.

Users can shorten or lengthen the number of results presented by changing the evaluation year of the report. All results beyond the evaluation year are then filtered out of the report.

Users can infer what are favourable investment decisions from this report by comparing what the preferred investments are per scenario or year. For example, if all growth scenarios and strategies agreed upon what the first intervention per feeder should be, then this is a strong signal of what the starting investment should be.

Figure 25: Example output from costing assessment

LV Multi Scenario Analysis

Evaluation year	2050

Growth Scenario 1 High Growth

Strategy	Year	Intervention	Location	Actual Cost	£NPV
All Knowing Strategy	2019	Overlay Feeder 1	1) Node 100 to node 3 distance 140m with CU 0.06	78250	78250.00
	Year	Intervention	Location	Actual Cost	£NPV
Flexibility Minimum	2019	Overlay Feeder 1	1) Node 100 to node 3 distance 140m with ABC 50	78040	78040.00
	Year	Intervention	Location	Actual Cost	£NPV
Flexibility Maximum	2019	Overlay Feeder 1	1) Node 100 to node 3 distance 140m with ABC 50	78040	78040.00

Growth Scenario 2 Even Spread

Strategy	Year	Intervention	Location	Actual Cost	£NPV
All Knowing Strategy	2046	SAVE	Community Coaching	4000	829.47
	2053	Overlay Feeder 1	1) Node 100 to node 3 distance 140m with AL 0.1	78390	
	2053	Overlay Feeder 3	1) Node 100 to node 30 distance 40m with ALPEX 300 2) Node 33 to node 36 distance 30m with ALPEX 300	41400	
	Year	Intervention	Location	Actual Cost	£NPV
Flexibility Minimum	2046	Overlay Feeder 1	1) Node 100 to node 3 distance 140m with CU 0.06	78250	16226.54
	2052	Overlay Feeder 3	1) Node 100 to node 30 distance 40m with ALPEX 300	23360	
	2055	Overlay Feeder 1	1) Node 100 to node 3 distance 140m with AL 0.1	78390	
	2057	Overlay Feeder 3	1) Node 33 to node 36 distance 30m with ALPEX 300	18040	
	2059	Overlay Feeder 1	1) Node 100 to node 3 distance 140m with AL 0.1	78390	
	Year	Intervention	Location	Actual Cost	£NPV
Flexibility Maximum	2046	SAVE	Community Coaching	4000	829.47
	2053	Overlay Feeder 3	1) Node 100 to node 30 distance 40m with ALPEX 300	23360	
	2053	Overlay Feeder 1	1) Node 100 to node 3 distance 140m with CU 0.06	78250	

Growth Scenario 3 Distant

Strategy	Year	Intervention	Location	Actual Cost	£NPV
All Knowing Strategy	2041	Overlay Feeder 1	1) Node 100 to node 3 distance 140m with ABC 70 2) Node 16 to node 17 distance 10m with ABC 35	84795	32631.18
	2045	Overlay Feeder 3	1) Node 100 to node 30 distance 40m with ALPEX 300 2) Node 33 to node 36 distance 30m with ALPEX 300	41400	
	Year	Intervention	Location	Actual Cost	£NPV
Flexibility Minimum	2041	Overlay Feeder 1	1) Node 100 to node 3 distance 140m with AL 0.1	78390	30029.33
	2045	Overlay Feeder 3	1) Node 100 to node 30 distance 40m with ALPEX 300	23360	
	2049	Overlay Feeder 3	1) Node 33 to node 36 distance 30m with ALPEX 300	18040	
	2052	Overlay Feeder 1	1) Node 100 to node 3 distance 140m with OAL 0.05	78502	
	2055	Overlay Feeder 1	1) Node 100 to node 3 distance 140m with WAVE 70	78530	
	2056	Overlay Feeder 1	1) Node 100 to node 3 distance 140m with ABC 70	78670	
	2057	Overlay Feeder 1	1) Node 16 to node 17 distance 10m with ABC 35	6125	
	Year	Intervention	Location	Actual Cost	£NPV
Flexibility Maximum	2041	Overlay Feeder 1	1) Node 100 to node 3 distance 140m with AL 0.1	78390	30029.33
	2045	Overlay Feeder 3	1) Node 100 to node 30 distance 40m with ALPEX 300	23360	
	2049	Overlay Feeder 3	1) Node 33 to node 36 distance 30m with ALPEX 300	18040	
	2052	Overlay Feeder 1	1) Node 100 to node 3 distance 140m with OAL 0.05	78502	
	2055	Overlay Feeder 1	1) Node 100 to node 3 distance 140m with WAVE 70	78530	
	2056	Overlay Feeder 1	1) Node 100 to node 3 distance 140m with ABC 70	78670	
	2057	Overlay Feeder 1	1) Node 16 to node 17 distance 10m with ABC 35	6125	

Growth Scenario 4 Low Growth

Strategy	Year	Intervention	Location	Actual Cost	£NPV
All Knowing Strategy	2044	Overlay	1) Node 100 to node 30 distance 40m with PDS 510	23196	5404.64
	2054	Overlay	1) Node 100 to node 30 distance 40m with ALPEX 300	23360	
	Year	Intervention	Location	Actual Cost	£NPV
Flexibility Minimum	2044	Overlay	1) Node 100 to node 30 distance 40m with PDS 510	23196	5404.64
	2054	Overlay	1) Node 100 to node 30 distance 40m with ALPEX 300	23360	
	Year	Intervention	Location	Actual Cost	£NPV
Flexibility Maximum	2044	Overlay	1) Node 100 to node 30 distance 40m with PDS 510	23196	5404.64
	2054	Overlay	1) Node 100 to node 30 distance 40m with ALPEX 300	23360	

To allow the user to understand the least risk investment option and value of optionality, a form of regret table is presented on the Regret Table tab, an example of which is shown in Figure 26. This table allows users to understand the value of optionality.

For each investment strategy, the regret table lists the total NPV per each growth scenario and then shows how much investment regret would be experienced if the user committed to one of the three strategies. Investment regret is an expression of what is being risked by committing to one investment strategy and the event of an alternative growth outcome occurring.

The regret is expressed as the difference between the cheapest investment strategy, per growth scenario, and the strategy being considered. The Regret table then lists the:

- Regret per strategy per growth scenario.
- The worst least regret, per strategy, across all growth scenarios. This represents the largest investment regret associated with each strategy.

In the case of Figure 26, the table shows that the least regret approach, in this case, would be to follow the flexibility maximum strategy. Reference by the user back to the costing assessment tab would explain the sequence of interventions that were favoured.

Figure 26: Example output from Regret Table (multiple scenarios)

	No Growth	Low Growth	Medium Growth	High Growth		
Strategy	Outcome	Outcome	Outcome	Outcome		
	Scenario1	Scenario2	Scenario3	Scenario4		
All Knowing	£11,505.66	£173,869.72	£278,867.23	£248,924.63		
Flexibility Max	£12,198.31	£53,295.04	£97,414.51	£101,075.66		
Flexibility Min	£12,698.31	£55,295.04	£100,414.51	£105,075.66		
Minimum	£11,505.66	£53,295.04	£97,414.51	£101,075.66		
Maximum	£12,698.31	£173,869.72	£278,867.23	£248,924.63		
Strategy	Least Regret	Least Regret	Least Regret	Least Regret	Worst Least Regret	Sum of Least Regret
All Knowing	£11,505.66	£173,869.72	£278,867.23	£248,924.63	£278,867.23	£713,167.24
Flexibility Max	£12,198.31	£53,295.04	£97,414.51	£101,075.66	£101,075.66	£263,983.51
Flexibility Min	£12,698.31	£55,295.04	£100,414.51	£105,075.66	£105,075.66	£273,483.51

It is important to understand though that this regret table compares the performance of the different investment strategies or using SAVE or physical interventions and not necessarily individual interventions. To understand what actions should be commissioned by which date, an assimilation table can be developed based on the results format shown in Figure 25, which monitors what is the next decision to be made for a substation to remain within limits following a particular strategy.

For example, if it were decided by the user to follow the all-knowing investment strategy, then the results in Figure 25, would imply that the user needs to consider the works described in Table 4. By following a rolling process which monitors LCT growth on the substation and employs the Multi-Scenario report, users will have a watch list of which investments need to be made by when. If employed at scale, this tool would ultimately allow budgeting of LV capacity interventions across a geographic area.

Table 4: Investment Assimilation Table

Growth Scenario	First Intervention	Investment Trigger Date
1	Feeder 1 – Overlay 140 Metres of cable	2019
2	Feeder 1 – Community Coaching	2046
3	Feeder 1 – Overlay 150 Metres of cable	2041
4	Feeder 1 – Overlay 40 Metres of cable	2044

6.2 Smart feasibility

Users may assess whether one user-supplied electricity storage installation can be used as an alternative to any of the solutions presented within the costing output.

Figure 27: Example input for Smart Interventions report

Storage Power (kW)	100
Storage Energy (kWh)	150
Duration of Peak	10
Costing Assessment Scenario	1
Strategy	All Knowing Strategy
Evaluation Year	2028
Run Assessment	

Before the commencement of this study, the user must state the assumptions for:

- The power output of one the storage unit in kW.
- The energy storage capacity of the storage unit in kWh.
- The assumed duration, in hours of the peak demand on the feeder.
- Which of the costing assessment scenarios that are the basis for financial comparison (this refers to scenario 1,2,3 or 4).
- Which strategy is to be the basis for comparison (i.e. all-knowing, flexibility maximum, flexibility minimum).
- The year at which the net present value of the costing evaluation results is to be assessed.

The storage feasibility can then review the load flow results from the LV load flow engine to decide whether the storage assumptions can be used as an alternative reinforcement. An example of this output is shown in Figure 28.

Figure 28: Example output from storage feasibility report

Description	Price Ceiling	Feeder	First Node	Year 0	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
Size of Winter Peak Overload (kW)	£76,230.00	1	3	8.9	0	0	0	0	0	0	0	0	0	0
Is storage technically feasible?				Yes										
Size of Winter Peak Overload (kW)	£41,800.00	2	25	90.1	0	0	0	0	0	0	0	0	0	0
Is storage technically feasible?				No										
Size of Winter Peak Overload (kW)	£53,537.50	3	30	103.6	0	0	0	0	0	0	0	0	0	0
Is storage technically feasible?				No										
Size of Winter Peak Overload (kW)	£66,071.00	4	48	26.3	0	0	0	0	0	0	0	0	0	0
Is storage technically feasible?				No										
Size of Winter Peak Overload (kW)	£0.00	5	56	0	0	0	0	0	0	0	0	0	0	0
Is storage technically feasible?														
Size of Winter Peak Overload (kW)	£0.00	6	62	0	0	0	0	0	0	0	0	0	0	0
Is storage technically feasible?														

Each feeder connected to the substation is assessed for suitability against the storage solution through:

- Use of the price ceiling, which is the interest earnt on the counterfactual investment for that feeder. For storage to be an economic proposition, then the annual cost of the utility to obtain those services must be less than the price ceiling.
- The technical feasibility assessment which checks whether the size of the largest winter peak overload on the LV feeder is smaller in terms of energy and power than the assumed storage unit.

6.3 Standalone pricing report

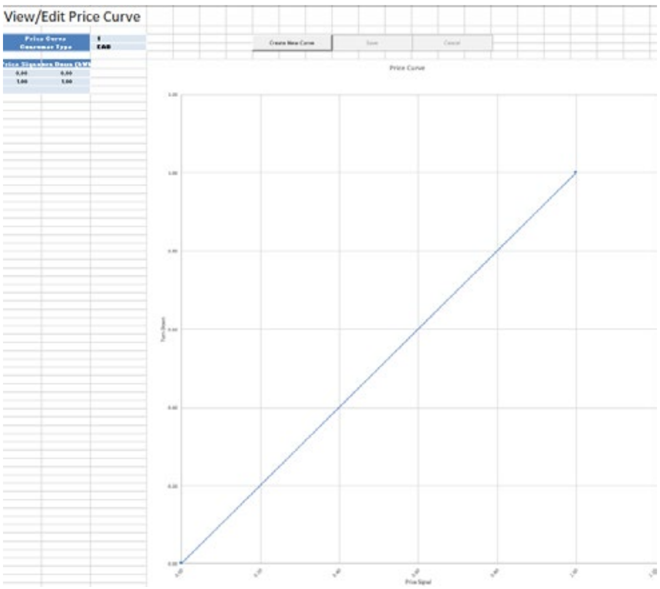
The standalone pricing report allows users to calculate the requirements of cost signals as a standalone report outside of the multi-scenario assessment process.

The functionality of this report is also replicated within the multi-scenario analysis, but this report allows standalone analysis.

Each customer type will be represented by an elasticity relationship which determines the amount of "turn down" in electrical power consumption that each customer type would be expected to give under winter peak consumption conditions for a given price signal. These assumptions reside within the backing store and should nominally be controlled by the administrator. Users can also update price curves and assign them to customer types through the interface shown in Figure 29.

For the price curve functionality to work, the administrator will also need to have assigned a price curve assumption to each consumer type.

Figure 29: Example of customer price elasticity curves



Before the assessment, users will also have to assign a global banding price signals the price signals assessment page, as shown in Figure 30. These bandings set the targets beneath which customers do not respond to price signals.

Figure 30: Example of customer price banding

Price Signal	Insensitive Below Target
0	0
0.15	0.15
0.25	0.35
0.35	0.5
0.45	0.75

To complete a stand-alone price signal assessment, users must specify the growth parameters using the same convention as 6.1.2.

When the study is complete, users will be presented with a report as shown in Figure 31. This figure focuses on the transformer report, but the available output fields are the same for each feeder.

Figure 31: Example of customer price elasticity curves

Transformer											
Description	Year 0	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
Size of Winter Peak Overload (kW)	20	20	20	20	20	20	20	20	20	20	20
Other Feeder Overload	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Required Tariff	£0.43	£0.43	£0.43	£0.43	£0.43	£0.43	£0.43	£0.43	£0.43	£0.43	£0.43
Cost of Tariff	£18,550.00	£18,550.00	£18,550.00	£18,550.00	£18,550.00	£18,550.00	£18,550.00	£18,550.00	£18,550.00	£18,550.00	£18,550.00

The first field reports the size of the winter peak overload for the asset in question. If it is a feeder, then the overload reported relates to the first branch of the feeder.

This application assumes that price signals are targeted at solving winter peak overloads. If any other overloads are observed on any other part of the feeder or on the transformer of either an import or an export variety, the "other feeder overload" field will turn positive. This flag is intended to warn users that price signals may not be a suitable solution and that use of the multi-scenario analysis should be considered to review the cheapest way to solve all the observed problems.

The required tariff relates to the required incentive per customer that is required to motivate sufficient turndown. The overall cost of tariff confirms the total sum that would have to be spent through price signals to resolve the constraint.

6.4 HV/EHV module

Since the issue of the SDRC 7.2 report, work has been undertaken to design and develop the HV and EHV pricing module.

The purpose of the HV/EHV module is to understand whether SAVE based interventions can provide a technical and economically feasible alternative to capital reinforcement of the HV or EHV system.

For the purpose of the SAVE project, the functionality of this module has been limited to dealing with network problems that are thermal loading problems under winter peak import conditions that can be resolved to a radial simplification. This decision was made to avoid including an HV/EHV load flow engine into the HV/EHV module.

This module assumes that the HV or EHV planning engineer has already determined the cheapest capital intervention and wishes to understand whether SAVE interventions can be used to defer this capital scheme.

Before conducting this assessment, it is a pre-requisite that the census interface has been populated in the backing store as described in 5.4.

6.4.1 Definition of a network constraint

Users can apply the information from within the census interface by either specifying that the calculation should assess one single HV feeder or alternatively that a named constraint should be analysed.

The nomination of the single HV feeder or a named constraint takes place on the assessment runner tab as shown in Figure 32.

The build type allows either a "single HV feeder" or a "constraint" to be selected.

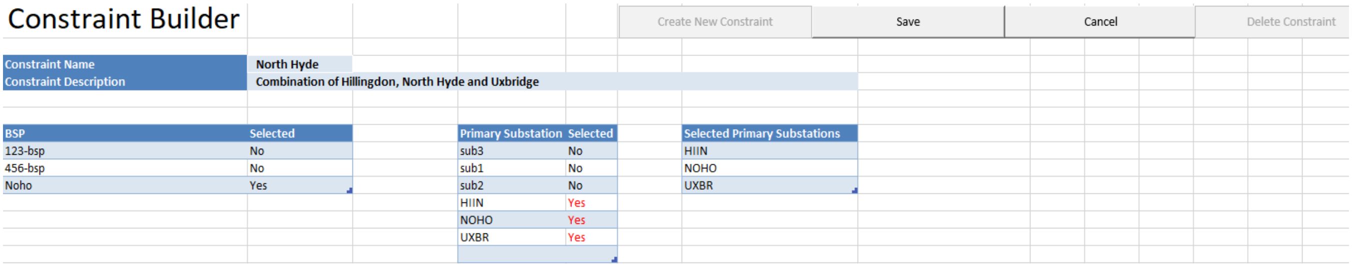
If "single HV feeder" is selected, then the user must specify a primary substation associated with the feeder before running the study. This will result in the module using the census data for the single HV feeder within the analysis.

Figure 32: Selection of constraint for study

Build Type	Single HV Feeder
Primary Substation	HIIN
Feeder	HIIN_E0L5
	Run

If build type "constraint" is selected, then the user will need to nominate a constraint group that has already been declared via the constraint builder page as depicted in Figure 33.

Figure 33: Constraint builder page



The constraint builder allows users to define a new constraint, by either selecting each primary substation or BSP substation. The action of setting the selection field next to a Primary substation or BSP from No to Yes adds the substation in question to the list of selected primary substations. In the case of the BSP selection, it will add all primary substations mapped to the BSP to that list.

Once the user is satisfied with the list of selected primary substations, it may be saved for use. Prior to saving the constraint, the user must name the constraint and give a brief description of what it represents.

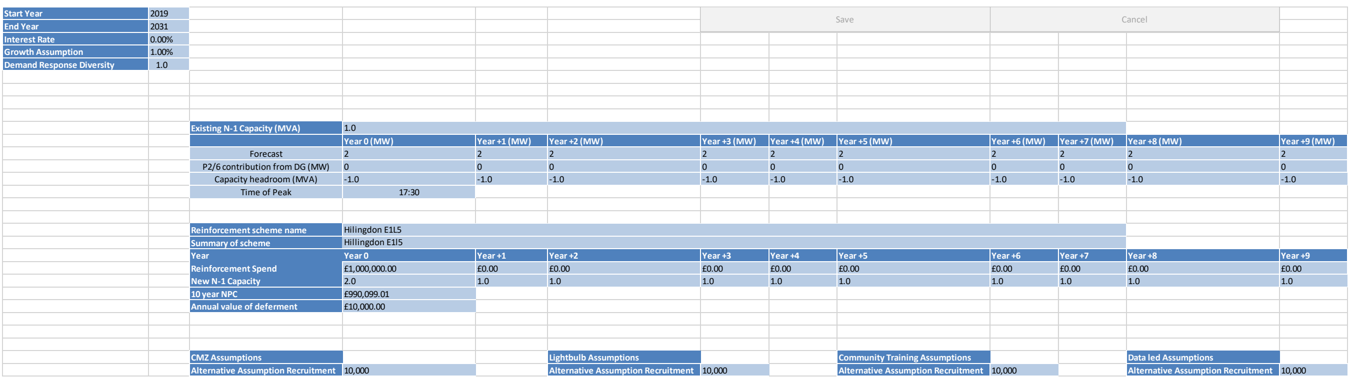
6.4.2 Network headroom and growth

To enable the headroom and possible mitigations, the network "problem" needs to be loaded into the module. An example of the user interface for this part of the process is shown in Figure 34.

This description is made in terms of:

- The start year and end year, which defines the span of the study.
- A linear growth rate expressing the background load growth applicable for the years beyond the 10-year manual forecast. The growth in years 0 to 10 should be included within the load forecast.
- The expected contribution to security from embedded generation.
- A diversity factor which reflects the aggregate difference in how different customers deliver any SAVE interventions.
- The expected annual peak electrical demand for the next 10 years for the existing network. This is entered manually by the user on the basis of known new connections and general expectation in the background load growth.
- The increase in capacity headroom created by the cheapest reinforcement scheme. This is entered manually by the user.
- The cost of creating the new capacity headroom. This is entered manually as a time series of investments by the user.

Figure 34: HV/EHV study input screen.



6.4.3 Technical and Financial comparison of interventions

The tab assessment runner launches the analysis of the interventions and reports the technical feasibility as well as the expected cost for each intervention, an example of which can be seen in Figure 35.

Figure 35: HV/EHV comparison of intervention table

Run

		Year 0	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20
	Annual value of defered reinforcement	£10,000.00																				
	Headroom deficit (kW) (calculation)	-900	-1200	-600	-700	-900	-900	-900	-900	-900	-900	-920	-940	-960	-980	-1000	-1020	-1040	-1060	-1080	-1100	-1120
	Total customers within constraint (Aggregation)	30000	30000	30000	30000	30000	30000	30000	30000	30000	30000	30000	30000	30000	30000	30000	30000	30000	30000	30000	30000	30000
CMZ/price signal	Maximum turn down (kW) available (maximum delivery and particpation)	-500	-500	-500	-500	-500	-500	-500	-500	-500	-500	-500	-500	-500	-500	-500	-500	-500	-500	-500	-500	-500
	Cost to deliver at maximum participation and maximum delivery	£20,000	£20,000	£20,000	£20,000	£20,000	£20,000	£20,000	£20,000	£20,000	£20,000	£20,000	£20,000	£20,000	£20,000	£20,000	£20,000	£20,000	£20,000	£20,000	£20,000	£20,000
	Cost to deliver at Maximum participation and minimum delivery	Insufficient F	Insufficient	Insufficient	Insufficient	Insufficient	Insufficient	Insufficient	Insufficient	Insufficient	Insufficient	Insufficient	Insufficient	Insufficient	Insufficient	Insufficient	Insufficient	Insufficient	Insufficient	Insufficient	Insufficient	Insufficient F
Low energy light bulbs	Total feasible Turn down (kW)	-100	-100	-100	-100	-100	-100	-100	-100	-100	-100	-100	-100	-100	-100	-100	-100	-100	-100	-100	-100	-100
	Minimum recruitment target (number of customers)	Insufficient c	Insufficient	Insufficient	Insufficient	Insufficient	Insufficient	Insufficient	Insufficient	Insufficient	Insufficient	Insufficient	Insufficient	Insufficient	Insufficient	Insufficient	Insufficient	Insufficient	Insufficient	Insufficient	Insufficient	Insufficient c
	Cost to procure total coverage	£0	£0	£0	£0	£0	£0	£0	£0	£0	£0	£0	£0	£0	£0	£0	£0	£0	£0	£0	£0	£0
Community Coaching	Total feasible Turn down (kw) using all SAVE customers	-200	-200	-200	-200	-200	-200	-200	-200	-200	-200	-200	-200	-200	-200	-200	-200	-200	-200	-200	-200	-200
	Minimum recruitment target to resolve constraint (Customers)	Insufficient c	Insufficient	Insufficient	Insufficient	Insufficient	Insufficient	Insufficient	Insufficient	Insufficient	Insufficient	Insufficient	Insufficient	Insufficient	Insufficient	Insufficient	Insufficient	Insufficient	Insufficient	Insufficient	Insufficient	Insufficient c
	Cost to procure minimum recruitment target	Insufficient c	Insufficient	Insufficient	Insufficient	Insufficient	Insufficient	Insufficient	Insufficient	Insufficient	Insufficient	Insufficient	Insufficient	Insufficient	Insufficient	Insufficient	Insufficient	Insufficient	Insufficient	Insufficient	Insufficient	Insufficient c
Data led engagement	Total feasible Turn down (kw)	-200	-200	-200	-200	-200	-200	-200	-200	-200	-200	-200	-200	-200	-200	-200	-200	-200	-200	-200	-200	-200
	Minimum recruitment target (Customers)	Insufficient c	Insufficient	Insufficient	Insufficient	Insufficient	Insufficient	Insufficient	Insufficient	Insufficient	Insufficient	Insufficient	Insufficient	Insufficient	Insufficient	Insufficient	Insufficient	Insufficient	Insufficient	Insufficient	Insufficient	Insufficient c
	Cost to procure minimum recruitment target	Insufficient c	Insufficient	Insufficient	Insufficient	Insufficient	Insufficient	Insufficient	Insufficient	Insufficient	Insufficient	Insufficient	Insufficient	Insufficient	Insufficient	Insufficient	Insufficient	Insufficient	Insufficient	Insufficient	Insufficient	Insufficient c

Figure 36: Financial overview of HV/EHV solutions

	Investment Requirements																					
		Year 0	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20
Value of defering of "reinforcement"	£35,040.00	£1.00	£300,000.00	£700,000.00	£0.00	£0.00	£0.00	£0.00	£0.00	£0.00	£0.00	£0.00	£0.00	£0.00	£0.00	£0.00	£0.00	£0.00	£0.00	£0.00	£0.00	£0.00
Cost to procure "CMZ/price signal approach"		£20,000.00	£20,000.00	£20,000.00	£20,000.00	£20,000.00	£20,000.00	£20,000.00	£20,000.00	£20,000.00	£20,000.00	£20,000.00	£20,000.00	£20,000.00	£20,000.00	£20,000.00	£20,000.00	£20,000.00	£20,000.00	£20,000.00	£20,000.00	£20,000.00
Cost to procure Low Energy Light Bulbs	£0.00	£0.00	£0.00	£0.00	£0.00	£0.00	£0.00	£0.00	£0.00	£0.00	£0.00	£0.00	£0.00	£0.00	£0.00	£0.00	£0.00	£0.00	£0.00	£0.00	£0.00	£0.00
Cost to procure Data informed engagement	£0.00	£0.00	£0.00	£0.00	£0.00	£0.00	£0.00	£0.00	£0.00	£0.00	£0.00	£0.00	£0.00	£0.00	£0.00	£0.00	£0.00	£0.00	£0.00	£0.00	£0.00	£0.00
Cost to procure Community Coaching	£0.00	£0.00	£0.00	£0.00	£0.00	£0.00	£0.00	£0.00	£0.00	£0.00	£0.00	£0.00	£0.00	£0.00	£0.00	£0.00	£0.00	£0.00	£0.00	£0.00	£0.00	£0.00

This report repeats the annual value of the deferred reinforcement and the headroom deficit, as per the feeder study input page.

The total number of customers within the feeder or the constraint are also reported.

The price signal field reports the customer payment level and the total cost of intervention per year required to defer the constraint. If the size of the overload is greater than the flexibility that can be provided by customers, then the report will announce that there is 'insufficient resource'. This report assumes that customer recruitment to deliver turn down due to price signals is 100% unless defined in the consumer profiles page.

The price signal section reports:

- The total amount of turn down available within the constraint under winter peak conditions.
- The tariff signal that would have to be offered across all customers to be able to resolve the constraint.
- The cost of offering that price signal to all customers.

The low energy lightbulbs section reports:

- The total amount of turn down available if each customer within the constraint proceeded with low energy lightbulbs.
- The minimum number of customers that should be recruited to be able to resolve the HV or EHV overload with low energy lightbulbs. This assumes that the demographics of customers that are recruited represented the overall demographic. If the number of customers or turn down per customer means that it is not technically feasible to remove the overload by this method, then the calculation will report "insufficient resource".
- The cost to deliver a low energy lightbulb strategy if every SAVE customer within the constraint is recruited.
- How much turn down is delivered if more than the minimum number of customers are recruited, again assuming that the recruitment demographic is representative of the overall feeder. If there are not enough customers to deliver this target, then this will be reported, and the calculation will not finish.
- How much does it cost, per year to recruit the increased number of customers.

The community coaching section reports:

- The total amount of turn down available if each customer within the constraint responded to community coaching.

- The minimum number of customers that should be recruited to be able to resolve the HV or EHV overload using community coaching techniques. This assumes that the demographics of customers that are recruited represented the overall demographics of the constraint. If the number of customers or turn down per customer means that it is not technically feasible to remove the overload by this method, then the calculation will report "insufficient resource".

- The cost to deliver a community coaching strategy if the minimum number of SAVE customers within the constraint is recruited.

- How much turn down is delivered if more than the minimum number of customers are recruited, again assuming that the recruitment demographic is representative of the overall feeder. If there are not enough customers to deliver this target, then this will be reported, and the calculation will not finish.

- How much does it cost, per year to recruit the increased number of customers.

The data led engagement report shows

- The total amount of turn down available if each customer within the constraint responded to data led engagement.

- The minimum number of customers that should be recruited to be able to resolve the HV or EHV overload using data led engagement techniques. This assumes that the demographics of customers that are recruited represented the overall demographics of the constraint. If the number of customers or turn down per customer means that it is not technically feasible to remove the overload by this method, then the calculation will report "insufficient resource".

- The cost to deliver a data-led engagement strategy if the minimum number of SAVE customers within the constraint is recruited.

- How much turn down is delivered if more than the minimum number of customers are recruited, again assuming that the recruitment demographic is representative of the overall feeder. If there are not enough customers to deliver this target, then this will be reported, and the calculation will not finish.

- How much does it cost, per year to recruit the increased number of customers.

The overall financial review, as depicted in Figure 36, allows a comparison of the annual cost to implement each approach. The most advantageous approach can be assessed by comparing the annual cost of implementing a SAVE intervention against the value of differing capital reinforcements.

6.4.4 Application of the HV/EHV module

The features of the HV/EHV module allow users to review a known capacity limitation on the network and investigate the technical and economic feasibility of alternative solutions.

For example, the feasibility of price signals can be investigated by comparing the price signal report to the calculation of the annual interest earnt on a capital intervention scheme that would be required to resolve the constraint.

Alternatively, this tool could be used to conduct due diligence of responses to constraint managed zone tenders to investigate whether the assumptions used are realistic in their approach to managing the constraint.

The application of this tool is currently limited to network issues that can be simplified down to a radial network model and also those which are reflective of a winter peak import restriction.

7

NETWORK MODEL SPECIFICATION

Previous works in SDRC 7.1[5] provided a functional specification for the SAVE Network Model. An updated document was provided in SDRC 7.2 in December 2017 which explained progress against the specification.

The following tables provide a summary of the requirements within the functional specification and provide a summary and evidence of the functional specification being met or provides an update on development. In all tables, a colour scheme has been used to indicate the present state of development of the functional specification. The convention used to allocate the colour code is summarised in Table 5.

Table 5: Colour code convention

Colour	Description
Grey	Some initial scoping but capability development pending completion of dependent tasks
Orange	Significant demonstration of core capability achieved, but full capability not yet complete
Green	Item Complete

7.1 User interface requirements

Section 3.2.1 of the functional specification set out the requirements summarised in Table 6. This table provides a summary of the status and refers to sections earlier in this report where further demonstration can be found. This table is reflective of the updated progress since SDRC 7.2.

Table 6: User interface requirements

Requirement		Status
Run Single period (e.g. year) or multi-period assessments)	Green	Complete as shown in sections 5.3 and 5.7
Select the networks to run the assessment, from a single network, selection of network templates or a custom-built network	Green	Complete as shown in section 5.1
Compare different energy efficiency intervention scenarios	Green	As shown in 5.7 and this capability is also used by the multi-scenario analysis introduced in 6. The HV/EHV module also compares energy efficiency interventions as per 6.4

7.2 Network Template Requirements

Section 3.2.2 of the functional specification set out the requirements summarised in Table 7. This table provides a summary of the status regarding the delivery of the requirements and refers to sections later in this report where further demonstration can be found. This table is reflective of the updated progress since SDRC 7.2.

Table 7: Network Template Requirements

Requirement		Status
Include default templates	Green	Complete as shown in section 5.1
Templates will show a detailed nodal representation of distribution transformers and all downstream feeders	Green	
Network templates will be customisable	Green	

5 SDRC 7.1: Initial Network Model, Castro, Potter & Mukherjee Et Al, EA Technology Ltd, 05/12/14

7.3 Network Builder

Section 3.2.3 of the functional specification states a requirement to incorporate a network builder module. The network builder module is intended to allow network planners to rapidly model a specific low voltage area by defining the main assets, technical parameters and nodes of a network. This table is reflective of the updated progress since SDRC 7.2.

Table 8: Network Builder Requirements

Requirement	Status
Network Builder Module	Complete as discussed in section 5.1

7.4 Intervention Modelling

The functional specification set out the requirements that are summarised in Table 9. This table provides a summary of the status and refers to sections earlier in this report where further demonstration can be found. This table is reflective of the updated progress since SDRC 7.2.

Table 9: Intervention Modelling Requirements

Requirement	Status
Simulate conventional solutions considering: - Cable overlays - Feeder splits - Asset replacement - Load transfer to a different feeder.	The future assessment capability (section 5.7) and the multi-scenario capability (Section 6) allow these simulations
Simulate energy efficiency solutions using: - LED Lighting, - Engagement Campaigns, - TOU tariff, - Community Coaching	The future assessment capability (section 5.7) and the multi-scenario capability (Section 6) allow these simulations This capability is also used by the HV/EHV module (section 6.4) The standalone price signals report also simulates price signals (section 6.3)
Allow Comparison between interventions studied	The future assessment capability (section 5.7) and the multi-scenario capability (Section 6) allow these simulations This capability is also used by the HV/EHV module (section 6.4)

7.5 Scenario Builder

The requirements for the scenario builder are described in section 3.25 of the functional requirements. This table is reflective of the updated progress since SDRC 7.2.

Table 10: Scenario Builder

Requirement	Status
Scenario Builder	The future assessment capability (section 5.7) and the multi-scenario capability (Section 6) shows how different growth scenarios can be applied

7.6 Load Flow Engine

Section 3.26 of the functional requirements stated the expectations summarised in Table 11. This table also summarises the status of the present development. This table is reflective of the updated progress since SDRC 7.2.

Table 11: Load Flow Engine Functional Requirements

Requirement	Status
Full half hourly steady state and load flow analysis	SDRC 7.2 introduced the capability that had been developed to enable 365-day analysis per year and into the future.
Use of ADMD style input data	As discussed in SDRC 7.2 the NM tool is dependent on the UoS profiles which is considered to provide a superior facility to ADMD without slow performance.
The scope of analysis to include from the distribution transformer to the feeder ends	As shown in Table 1 and Figure 7, the load flow engines consider the secondary transformer and also entire feeders
Based upon DEBUT and EGD load flow engines	As discussed in section in 5.1 of this report.

7.7 Future load growth module

The future load growth module will assess the likely effects of SAVE energy efficiency interventions on the LV area against future load growth due to low carbon technology such as electric vehicles, heat pumps and domestic PV. Section 3.2.6 of the functional specification made a number of requirements which are summarised in Table 12 with an update upon the delivery status.

Table 12: Functional requirements for future load growth module

Requirement	Status
Make allowance for load growth for Low Carbon Technology	Sections 5.7 and 6 show how future growth of LCT can be explored
Hold load profiles for common LCT's including: Heat Pumps Electric Vehicles Solar PV generation	Section 5.5 and 5.4 describes the fact that this data is held and used by the model
Perform assessment over many years from templates or customer networks	Sections 5.7 and 6 establishes that the interventions can be run over many years. Sections 5.1 show how custom or template networks can be constructed
Allow the user to time the reinforcement on to the system to understand which year reinforcement is required.	Sections 5.7 and 6 show how the user can understand in which year the capacity runs out and reinforcement is required.

7.8 Customer Model interface

The Network Model interface will take input from the Customer Model via a building script. The functional requirements expressed in 3.2.8 of the functional specification and progress to date are against these requirements are summarised in Table 13.

Table 13: Customer Model interface requirements

Requirement	Status
Semi-automated link so inputs from UoS Customer Model can be transferred into the Network Model	The use of the Microsoft Access backing store allows an overall expression of the customer models to be rapidly loaded into the backing store.
Customer Model will take the form of direct links to other Microsoft excel tools using a 'CSV' file loader	The use of the Microsoft Access backing store allows an overall expression of the customer models to be rapidly loaded into the backing store. This can be done via .CSV files or Microsoft Excel files
Aggregation layer to convert source data into a useable form by the Network Model	The use of the Microsoft Access backing storage ensures that the data from the Customer Model is loaded in a form that ensures usability by the Network Model via the census interface.

7.9 Interface to Network Model

Since SDRC 7.2 work has been undertaken which has changed the proposed structure of the Network Model which has joined the Pricing model to the Network Model. This means that original requirements of the specification to have a defined interface between the Pricing Model and the Network Model became superfluous. Table 14 discusses the functional specification and how these requirements have been met.

Table 14: Pricing Model interface functional requirements

Requirement	Status
The Pricing Model interface will be via a semi-automated link for results to be ported out of the Modelling Tool	Following development subsequent to SDRC 7.2, the Pricing model was built to be integral to the Network Model. This removed the requirement to have an interface.
The interface will take the form of direct links to other 'Microsoft Excel' tools, developing a '.csv' file loader for data exchange or developing an XML interface	Following development subsequent to SDRC 7.2, the Pricing Model was built to be integral to the Network Model. This removed the requirement to have an interface.

7.10 HV and EHV Module

The functional specification of the Network Model tool required an LV and an HV/EHV module to allow the user to estimate the effect of SAVE energy efficiency interventions on upstream networks. These requirements are summarised in Table 15 against the progress to date.

Table 15: HV and EHV Module

Requirement	Status
Estimate the effect of interventions on upstream networks	As described in 6.4, the HV/EHV module allows projection of SAVE interventions applied at LV to the HV or EHV system
Provide a method of understanding the number of inventions needed to mitigate an upstream loading issue	

7.11 Load profiles

The probabilistic method used in DEBUT[6] will be employed in the Network Model. The aggregation layer will process data from the Customer Model to generate DEBUT compatible load profiles with statistical diversity factors.

This probabilistic method will, however, be based upon customer load profiles. The functional requirements for load profiles and current status are described in Table 16.

Table 16: Probabilistic method and load profile functional requirements

Requirement	Status
The Network Model will store and use half hourly load data for each Customer type	As described in 6.4, the HV/EHV module allows projection of SAVE interventions applied at LV to the HV or EHV system
A method of accounting for the local variation of conventional household demand (probabilistic method), either due to the customer type or lack of diversity	As shown in 5.3, the Network Model uses both the mean average demand and the standard deviation in demand to account for variation in customer demand.
An ADMD value (a single figure, useful for speeding up assessments)	No, the NM tool is dependent on the UoS profiles which is considered to provide a superior facility to ADMD without slow performance.
A method of accounting for the local variation of the SAVE interventions (probabilistic method)	The NM utilises the random distribution of load readings that is expressed within the UoS intervention load profiles to account for variation in SAVE interventions.

6 DEBUT is the load flow engine used to calculate results and it is fully introduced in section 5.1

7.12 Overall modelling approach

Section 3.2.13 of the functional specification also set out a number of general requirements, which are summarised in Table 17 along with an update of status.

Table 17: Overall modelling approach functional requirements

Requirement	Status
Consider steady state voltage and thermal issues only	As shown in sections 5.5 and 5.7 this steady state loading and voltage assessment can be undertaken
The tool will estimate available capacity in kW until a thermal or voltage constraint is reached	Sections 5.5, 5.7 and 6 how the user can assess in which year the capacity of the network runs out.
Compare traditional reinforcement and energy efficiency reinforcements	As shown in sections 5.7 and 6 traditional and energy efficiency interventions can be compared
The model will observe the effects of these reinforcements on the LV and higher voltage	As shown in section 6.4 the HV/EHV module shows the effects of LV interventions at HV or EHV.
The analysis will consider the effect of connection phase allocation	As shown in section 5.2, the model considers phase allocation.
The analysis will consider the effect of local network topology and connection location	As shown in section 5.2, the model considers the local network topology
The precise point of connection within a low voltage network for individual customers will not be known	As discussed in section 5.2, the templates are dependent on the builder script to provide nominal connection points customers.
The Network Model will treat the individual energy requirements of customers independently. This shall include propensity of response to efficiency interventions independently	The Network Model allows individual customer types to be modelled. Each customer type can be modelled in terms of annual energy consumption, the propensity of response to SAVE interventions.
The Network Model will estimate the range of possible effects for a defined mix of customers as informed by the Customer Model	Because the model links a census model a network load flow representation and models the response to SAVE interventions per customer, each network can have the range of effect of SAVE interventions to be assessed.
The Network Model will define network performance estimates using a probabilistic function	Because the Network Model uses the data in Customer Model and the ACE 49 approach, then the model is capable of modelling network performance using a probabilistic function.
The Network Model will compare energy efficiency interventions with more traditional techniques for reinforcements on the local low voltage network and at higher voltages	As shown in sections 6 and 5.7 this model compares traditional interventions against SAVE interventions. The presence of the HV module also allows this to be done at HV or EHV network levels.
The Network Model will be interactive to allow the user to explore any number of possible scenarios or circumstances	Users can study up to 4 different growth scenarios. The number of scenarios was capped to avoid excessive running time.

Requirement	Status
The Network Model will provide outputs to the Pricing Model interface Depending on the scale and complexity, it may be reasonable for these interactions to be via a manual (cross-typed) transfer of details (low tens of numbers) or using standardised file structures (larger exchange of details) The specification of the interface will be driven by the need for user convenience but also the iterative nature of the project's models Consider steady state voltage and thermal issues only EA Technology will define the range of traditional (capacity increasing) techniques that are used for comparison and will encode their nature and effect on network performance into the NM for automatic comparison A user should not be required to set-up or define these techniques but should be able to clearly understand how these techniques have been applied by the model and adjust if necessary The NM will enable users to configure their own network(s) therefore ensuring the model can be readily adjusted to reflect local circumstance and practice across all UK DNOs The network configuration parameters should encompass both the characteristics of the network under assessment as well as the nature of traditional techniques used in comparisons Whilst the NM and the traditional techniques used in comparisons will be based on a simulated network, the nature of results and the process by which they have been established will be transparent and readily interpretable The project will trial energy efficiency interventions on an iterative basis with the first iteration being used to refine the second iteration. Prior to the first iteration, target energy efficiency messages will be defined by considering the base-case levels of performance from the Network Model In advance of this, and as an indication of the type of message to be revealed by the Network model, an initial set of messages have been prepared from a highly generalized understanding of network need The Network Model will take inputs from the Customer Model. Depending on scale and complexity, it may be reasonable for these interactions to be via a manual (cross-typed) transfer of details (low tens of numbers) or using standardized file structures (larger exchange of details) The specification of the interface will be driven by the need for user convenience but also the iterative nature of the project's models	Because the Network Model and the Pricing Model are now within the same environment, the requirement for a defined interface for a file transfer is no longer a requirement The network model presents thermal and voltage results This has been done and it can be seen from section 5 that the solutions defined can be modelled and compared The user is not required to set up, define or model these techniques. The user is able to adjust them. Understanding of the techniques is disseminated through tool manuals As discussed in section 4.1 of SDRC 7.2 and also within this report, The Network Model holds a library where users can save standard component models of typical conductor types used on their network. These conductor types may then be used to help build the individual branches in the Network Model As described in section 4.2 users can upload templates, which can be configured to reflect local networks. As shown in section 5.2, networks can be represented on a node and branch representation of the network. When required, the length of the branches can be adjusted to suit network records. As demonstrated in this report, the network model produces network simulations and examples of the reports are recorded in this document. This report shows how outputs from the customer model are loaded into the Network Model and Pricing Model environment. This is done via a standardised file structure

7.13 Pricing Model approach

Many of the requirements and features for the Pricing Model are embedded in the preceding headings of section 7 but Table 18 summarises the remaining requirements.

Table 18: Pricing Model requirements

Requirement	Status
Conduct analysis across a number of growth scenarios to determine the most effective way to manage capacity across an LV network. The preferred solution should be an abutting sequence of interventions.	The multi-scenario analysis describes how users can investigate the most preferential investment strategy across a number of growth scenarios. The multi-scenario analysis provides an abutting sequence of interventions that would be required to keep the network compliant.
Use credible costs assumptions to ensure accurate costing of scenarios	All costing approaches used a fixed set of cost assumptions that can be controlled and locked by the administrator.
Allow comparison of the costs associated with using investment strategies that use physical and customer-led interventions.	The LV costing assessment and the HV/EHV module allow costing of strategies that use both SAVE interventions and physical interventions. The cost of SAVE interventions is assessed using the Customer Model to decide which interventions are technically feasible and then using fixed cost schedules to asses which measures are economic.
Allow demonstration of the effect of downstream interventions on the economic strategies for managing upstream systems	This functionality is shown in section 6.4
Use learnings from the SAVE trials to inform techno-economic analysis of potential network capacity interventions	This functionality is shown across sections 6.3, 6.4, 6.2 and 6

8

NETWORK MODEL WORKSHOP

SAVE's project bid document states the team will "host a workshop demonstrating [the] tool". The purpose of this activity is to support the integration of the network model and network investment tool into business as usual (BaU) across the DNO's. As the SAVE project has materialised and the network model has matured, SSEN has recognised a need to expand on this ask to best achieve the outcome of an appropriately integrated network model and network investment tool.

As a result, rather than host a single 'workshop' as required in the bid document the SAVE project team designed a programme of engagement activities, including workshops, both internally and with wider DNO's to support understanding of the NIT. Given this report's aim to provide evidence of the development of the network model and pricing model (as opposed the entire NIT) the below table of evidence focuses on activities relating more explicitly to these individual models. SAVE will report on activities that have contributed to the wider NIT in its project closedown report. This includes a two-hour workshop at SAVE's closedown event, a bespoke ENA roadshow advertisement event and a series of DNO roadshows.

Throughout the SAVE project, the team have hosted an array of meetings, workshops and presentations with internal planners and industry leads (specifically at the LCNI conference) to support in the development of the network model. The activities focused on below are not focused on the development of the network model and pricing model. They are aligned with the dissemination plan enacted to rollout the network model and pricing model in the build-up to the full release of the NIT at the start of June.

One of the key outputs of this series of workshops was the identification of the need for an operational report[7]. In discussions with planning engineers, it was clear that areas of consistency in approach such as modelling of SAVE customer types against existing customer types were crucial to address. Thus, forth the operational report is intended to help DNO's to understand the integration of the NIT with industry standards and procedures to ease the rollout of the tool into business as usual procedures. A version of SAVE's operational report can be found in appendix II.

7 Highlighted in SAVE's December 2018 Network Model workshop

Table 19: SSEN workshop summary

Date	Attendees	Workshop Purpose	Workshop Outcomes and Next Steps
December 2018	SSEN- Project Manager, Project Engineer, Project Analyst, Planning Standards Manager, Network Planner UoS- Project lead EA Tech- Project Lead TNEI- Principal Consultant, Technical Consultant	• Provide an overview to both network planners and TNEI of the final network model and pricing model scope and functionality, in addition to any final development edits. • Understand planning processes and procedures and how the network and pricing models would be impacted by these. • TNEI to bring an understanding of wider DNO planning policies.	• TNEI to produce an operational report noting potential integration points between NIT and industry standards and procedures. • SAVE project team to provide visual examples of how NIT can automate current and new processes to support the wider departmental understanding/rollout. • Discussions initiated around resourcing required to support testing of network investment tool against existing planning processes • TNEI to look over industry and SSEN internal procedures to understand overlap with/ changes needed to accommodate SAVE NIT.
April 2019	SSEN- Project Engineer, Project Analyst, Planning Standards Manager UoS- Project lead TNEI- Principal Consultant, Technical Consultant	• Discuss findings from TNEI study of SAVE models, industry standards and SSEN internal procedures. • Clarify NIT mechanisms and update on model evolution. • With all SAVE data collected (final data repository made on 3rd March 2019), to provide planners with a visual of network and pricing model interfaces (as per the last meeting) and to feed into bi-weekly 'sprint' updates of the final NIT.	• Creation of NIT validation plan including the need for an internal resource to support this process, to start in early May. • Planners highlighted concerns or limits around usability of the model to feed into final 'sprint'[8] based developments of the NIT. • An approach (Bayesian statistics) as to how network planners might manage risk in any outputs from the NIT to support behavioural trials in providing security of supply. • TNEI present some potential analytical techniques to the University of Southampton, to support customer model, which may further support and allow SAVE project to prove statistical significance.

8 Throughout the final three months of the project from final delivery of customer data the network model and pricing model were developed in bi-weekly 'sprints' between SSEN and EA TL.

Date	Attendees	Workshop Purpose	Workshop Outcomes and Next Steps
May 2019	SSEN- Project Manager, Project Engineer, Planning Standards Manager, Lead System Planning and Investment Engineer, Network Planner	• Having given planning resource 2 weeks to learn and test the intricacies network and pricing models as both an individual models and part of the NIT, to devise a clear workplan to test the NIT in existing procedures whilst disseminating to the wider team where the models and the tool add value (speed up, provide consistency or provide new network insight). • Ensure planning understand tools final capabilities and test those areas likely to be of most value to DNO's and DSO's to shape wider dissemination emphasis (NIT roadshows discussed in project closedown report) outside SSEN.	• The key value of the NIT is that it adds **consistency** and **automation**, planners won't need to select customers based on an asset; NIT does this automatically based on census data which should also be more precise/ tailored to a specific area. • Planner workplan broken down into four main areas for testing against current procedures (each module below is described in full detail in SDRC 8.2, Network Investment Tool). – Single Scenario[9] with connections and LV planners (including a comparison to substation monitored data to understand the accuracy of model vs real-life data) – Future Scenario[10] with LV planners – Multi-Scenario[11] with LV and HV planners looking and DSO development teams looking at smarter forecasting. – HV/EHV module[12] – HV planners looking at Constrained Managed Zones (CMZ) • Placeholder for review meeting in July to discuss how and where NIT could be rolled into BaU, future/tailored development (outside of SAVE spec) and integration with wider (internal and industry models)

9 Providing a snapshot of current substation loading
10 Providing a future insight into a substation loading across a specific load-growth scenario
11 Providing a future insight into a substation loading across a range of load-growth scenarios, using the pricing model to run different strategies for cost-effectively managing the constraint using smart (SAVE) or traditional reinforcement mechanisms
12 Examining load forecasting on the HV/EHV network and using the pricing model to run different strategies for cost-effectively managing the constraint using smart (SAVE) or traditional reinforcement mechanisms

9

SUMMARY, LIMITATIONS AND LEARNING

9.1 Summary

This report has demonstrated that the initial requirements of the functional specification have been delivered and has described how this has been achieved. The following sections describe some of the learning points and limitations which have been encountered and relate to the development of the Network Model and Pricing Model.

9.2 Architecture

It was originally envisioned that all pricing and incentive functionality would stand aside from the Network Model in a separate structure.

This architecture would have created inefficiencies in studying what the most advantageous network interventions would have been. For example, keeping the Network Model separate from the Pricing Model would have meant that all feasible investment sequences would have had to have been studied in the Network Model before the results were passed to the Pricing Model. This approach would have taken a large quantity of computational time before pricing could start as each possible option would need to be studied.

Allowing the Pricing Model and the Network Model to operate simultaneously allowed computational efficiencies to be obtained through avoiding the need to study investment sequences in the Network Model that were never likely to be economic.

9.3 Load flow engines

The Network Model uses two load flow engines that work in two very different ways which are not always interchangeable. The output from the EGD engine reports at the 30-minute resolution and is based on the use of the average power consumption of users. This engine can be used to study networks without LV connected generation.

In comparison, the DEBUT engine studies the network at 30-minute resolution but reports the worst 30 minute loading period of the day based on ACE 49 diversity methodology and assumes that all generation is set to zero. The DEBUT engine does, however, offer reduced computational difficulty as it is not based on iterative mathematical solutions which can sometimes fail to converge on a solution.

Both approaches are valid within their sphere of application, but the requirements to be able to conduct 365 days per year analysis, at the same time as offering ACE 49 diversity assumptions and always holding a capability to study networks with embedded generation within them can lead to conflicting requirements as to which engine should be used as the basis for reporting.

These dilemmas would be resolved by a load flow engine that could have a low computational overhead, which could apply generation analysis at the same time as using ACE49 diversity assumptions.

Traditionally Debut and EGD were configured to only hold winter peak ratings as the expectation was that peak loading would occur in winter seasons. To limit project complexity, this iteration of the Network Model holds the same limitations. Future development of this model or the load flow engines would allow year-round ratings to be applied.

9.4 Customer Model interface

Since the initial functional specification development work has been undertaken to refine the interface with the University of Southampton's Customer Model. This has led to the inclusion of a Microsoft Access database which acts as the backing store for all information except any CSV network templates.

A key learning point along this process is that the DEBUT engine may only ever hold 48 different load profiles. This limitation has been resolved by the introduction of a Microsoft access database to act as a backing store for the Network Model and Pricing Model.

These Customer profiles can be loaded for each customer type by the administrator loading them into the access database. Each customer type is associated with a load profile and the following features which are required to describe customer behaviour under energy efficiency interventions:

- Pricing elasticity curves to allow an analysis of price signals
- The turn down effect on the daily load curve resulting from data led engagement, low energy lightbulbs and community coaching.
- Erosion factors to show how the effect of the energy efficiency interventions degrades with time.

The aggregation layer and processing of customer records takes place within the University of Southampton Customer Model before being passed across to the Network Modelling tool database. Because the Microsoft Access database is located on each installation of the Network Model. The significance of having an Access database up-loading tool is that the customer models within each instance of the Access database can be regulated to ensure uniformity..

Because the Debut and EGD load flow engines are also limited to holding 50 consumer profiles, this has had the effect of limiting the number of consumer types that the customer interface could pass over for use in any one study.

9.5 Use of Excel

The initial requirement for the use of Microsoft Excel has allowed customers to be able to cut and paste results for their own manipulation and it will provide an environment that Microsoft users are familiar with.

Users are also provided with a connectivity map of the branches and nodes within the model via an add-in. This map, however, will bear no relation to any geospatial representations. Should there be future requirements to amend the Network Model to present network data in a geospatial domain, then it is likely that users will have to experience the Network Model and Pricing Model in an environment that could support graphical representations of the network.

A specialist energy consultancy

Solent Achieving Value from Efficiency (SAVE)

Operational Report

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Executive Summary

Overview

TNEI has been commissioned by Scottish and Southern Electricity Networks (SSEN) to produce an Operational Report for the Solent Achieving Value from Efficiency (SAVE) project.

SSEN has been delivering the SAVE project since 2014 when it was awarded funding from Ofgem via the Low Carbon Networks Fund (LCNF) mechanism. It is due to run until 2019. The aim of the project is to trial various energy efficiency and demand response measures, establishing their cost-effectiveness, predictability and sustainability when being considered as options to manage peak demand. The desired reductions in peak demand are in order to either delay or avoid network reinforcement that would otherwise be necessary due to congestion.

The SAVE project has identified potential barriers to the implementation of the trialled interventions, and more generally use of the Network Investment Tool (NIT) developed for more optimal decision-making. Potential barriers are categorised as being either ‘operational’, ‘commercial’ or ‘regulatory’ in nature, and their identification, exploration and mitigation is presented via a series of corresponding reports. This document is the “Operational Report”. Consideration of such barriers has been conducted within the context of the relevant standards and policies that SSEN (and other DNOs) follow – some of which are industry standards, others DNO-specific standards.

The innovative concepts which the SAVE project has been investigating, relevant to this operational report, are:

- The integration of energy efficiency and demand management techniques into network planning.
- The use of statistical methods to model patterns of customer demand, to establish customer types and to model each type’s responses to the SAVE interventions.
- Combining technical and economic aspects of network planning within a single tool.
- Determination of the merits of DNOs interacting with customers on demand reduction measures as opposed to energy suppliers or other parties.

Key learning from the project includes the following:

- The trials show consistent reductions in peak demand associated with interventions, (although these have not been shown to be statistically significant with the analytical tests that have been adopted);
- The definition of customer type profiles, based on data collected in the project, should enable an improved representation of customer demands. It has been demonstrated in the project that “average” profiles that don’t account for the identified key household characteristics can severely overestimate or underestimate the demand, compared to the more granular profiles developed in the project; and
- The integration of technical and economic aspects of network planning can help streamline analysis and decision-making processes. Each part of the Network Investment Tool is complex in its own right, but the integration of these into a single tool with a centralised user interface should ensure acceptable ease of use for network planners.

Planning and operational barriers to consider for implementation

The report sets out some of the existing operational factors which govern SSEN's processes with respect to planning and operation of their LV networks, including:

- The engineering standards to which SSEN must adhere.
- SSEN's own internal policies for network design.
- The "Social Constraint Management Zone" (SCMZ) concept which SSEN will use to implement SAVE methods.
- The internal stakeholders that SSEN will need to account for when implementing the outputs from SAVE.
- Factors unique to other DNOs which may be relevant for their own implementation of SAVE methods or the NIT.

The key barriers that we have highlighted for implementation are highlighted below:

- **EREP 130 and contracted vs non-contracted DSR:** EREP 130 explicitly recommends that time of use tariffs and other non-contracted DSR should (by default) not be used to aid network security unless there is clear evidence to establish a "strong link". However, there is some potential ambiguity about exactly how contracted vs non-contracted DSR are defined, and how SAVE interventions would be classified.
- **ACE Report 49 and determination of LV design demands:** The method outlined in the ACE49 report is crucial for establishing the interface between the network model and the customer model. The method dates back to the 1980s and is ambiguous in some areas, so there is a risk that this could lead to key parameters characterising customer demands being improperly specified. This might reduce the benefit of adopting the customer type profile approach developed in SAVE.
- **SSEN LV Design Policies:** SSEN's LV design policies mandates the use of many assumptions which are relevant to the implementation of SAVE methods into business as usual activities, as they dictate how demands should be estimated when establishing the requirements for LV networks. Other DNOs have similar LV design policies, with other similar assumptions about demand that apply to their whole LV network. It is likely that the SAVE customer model would not comply with some of the assumptions, and that design policies would need to be updated to reflect the learning and new approaches adopted from the SAVE trial.
- **The LV design process and constraint management zones:** The key route to market which has been discussed for the SAVE interventions is the Constraint Management Zone and potentially the Social Constraint Management Zones (CMZs). These are the commercial services for which SSEN invites flexibility tenders to help manage issues on its network. However, it is not clear how easily (S)CMZs could be used within the planning process for LV networks (given the very high volume of designs that SSEN may need to complete), or when designing new connections (given the very tight timescales that SSEN needs to work to). More thought is therefore needed as to how the SAVE outputs, including the efficiency of the interventions and the NIT, could be applied in these cases. It might be the case that, in the short term, the NIT is used more frequently for the HV and EHV networks.
- **Managing risk in the face of uncertain energy scenarios:** The NIT is capable of identifying the most suitable network solutions for up to four energy scenarios. At the time of finalising

this report, SSEN and its project partners were considering options for whether the NIT could alternatively be used (at some point in the future) to identify which network solutions are most suitable *across* these scenarios, e.g. by adopting approaches to minimise regret in the face of an uncertain future. Any developments in this area would need to be reflected in SSEN's planning and investment processes, and could potentially even require some regulatory changes if, for example, there are cases where the best course of action is for SSEN to invest before a need is established with 100% certainty.

Potential areas for improvement

In addition, we have considered in detail many aspects of the analysis undertaken through the project, and how these have been drawn together to produce a tool to be used for network planning. We have identified some areas for improvement that could be considered in more detail which may help to make the outputs of SAVE more useful or promote their integration into business as usual activities. These are summarised below.

- **The variability in customer responses to DSR interventions:** As in other similar trials, the SAVE trials show that different customers can respond in quite different ways to DSR interventions, and that the exact response elicited can be quite hard to predict for small groups and individuals. However, within the NIT, the response to each intervention is modelled as deterministic. This means that there is some risk to the network if the actual response achieved is less than the modelled response, although it may be possible to mitigate this to an extent within the existing NIT methodology.
  A fully probabilistic analysis that reflects the uncertain nature of responses could more accurately calculate the level of procurement required, given a specified acceptable level of risk that the intervention will be sufficient.
- **The statistical significance of demand reductions:** Related to the above, the analysis conducted to date has included an assessment of whether the observed reductions in demand are "statistically significant". Formally, this means assessing whether the observed differences in demand compared to the trial group are large enough that they are unlikely to have happened purely by chance, i.e. the hypothesis that the interventions don't actually have any impact on demand[1] is unlikely to be true, where 'unlikely' here means the probability is below a chosen threshold.
  The approach taken to determining statistical significance in the analysis we have reviewed appears to be conservative, as it considers each reduction in demand separately, rather than considering the overall likelihood of observing multiple reductions in demand. This means that the conclusion of limited statistical significance associated with the interventions may actually be somewhat pessimistic. Further analysis would be required to explore this in more detail.

Recommendations

On the basis of these areas, we have set out a number of recommendations for SSEN to consider before adoption into business as usual, which could build on the analysis and development done in the project to date, including:

[1] In this context, the hypothesis that the interventions don't have any impact on peak demand is known as the 'null' hypothesis.

- **Strengthening the perceived link between the SAVE interventions and demand reductions**, through adopting a different approach to determining statistical significance, including the adoption of a **different approach to the calculation of confidence intervals.**
- Scrutinising the **definitions of p and q** values that are used in conjunction with the ACE49 methodology, and potentially considering other ways to calculate these which might be more robust.
- Ensuring the **SAVE interventions align with EREP 130**, by clarifying definitions where required and ensuring evidence is readily available to help establish the link between any non-contracted DSR SAVE interventions and reductions in peak demand (in the manner described in the first bullet point).
- **Updating policies** where necessary, e.g. to account for margins of over-procurement for SAVE interventions, which could be calculated using a probabilistic model.
- Considering **methods for managing the risk related to the procurement of response** from SAVE interventions. This should include consideration of who is best placed to manage these risks – in some cases, the DNO may be able to get a more efficient response if it can give more information to its customers about its detailed requirements, and in many cases, certain types of providers (such as local organisation) may not be capable of managing certain types of risk. Other methods for more direct quantification of the risk associated with the response to interventions should be considered.
- **Validating the outputs of the Network Investment Tool against monitoring**, where possible, e.g. by modelling in the NIT the areas of the LV network where granular secondary substation monitoring has been installed and comparing the predictions of the tool to the outputs of these. There are parts of the NIT that will be very difficult to verify (e.g. due to the very long time-horizon considered within the analysis).
- Enabling **further analysis of the SAVE dataset**, potentially through openly sharing the data widely with industry, or even through open machine learning competitions, which often attract talented data scientists.

In addition, we have some more future-looking recommendations, such as modifying the customer model to account for variability between customers; updating customer profiles with new sources of data as these become available, e.g. smart meter records; and releasing the various models within the NIT in open formats, so that other DNOs may choose to adopt some parts of these and integrate them with their own existing tools.