MANCHESTER 1824

The University of Manchester

Title: **"Network Modelling and Reactive Power Absorbability Analysis" Work Package 2 - Part B**

Synopsis: This study uses the load models based on real-time monitoring data and develops EHV network models to investigate the capability of primary substations to deliver reactive power absorption services. The network models related to the reactive power absorption capability have been validated against the IPSA model provided by Electricity North West. The estimated network reactive power absorption capability has been validated against the measurements from the trials. Additionally, the network demand reduction capability has been studied for the modelled EHV network. The key outcome of *Work Package 2 - Part B* is the analysis that confirms the EHV network reactive power absorption capability across the Electricity North West's network.

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Prepared For: Kieran Bailey, Future Networks Engineer
Steve Stott, CLASS Technical Engineer
Electricity North West, UK

Prepared By: Mr Linwei Chen, Mr Yue Guo and Dr Haiyu Li,
The University of Manchester
Sackville Street, Manchester M13 9PL, UK

Contacts: Dr Haiyu Li
+44 (0)161 306 4694
haiyu.li@manchester.ac.uk

The results and discussions provided in this report are outcomes of preliminary analyses and 'proof of concept' performed at selected subset of substations of a particular electricity distribution network under specific operating conditions and is not guaranteed to be the same for other sites or other networks. The readers should use this document as guidance and at their own responsibility. Any omissions or errors, if identified, should be reported to the authors.

Executive Summary – Work Package 2 Part B

This report presents the research work and the key outcomes of Work Package (WP) 2 - Part B of the Customer Load Active System Services (CLASS) project. The WP2-Part B aims to assess the Electricity North West reactive power absorption capability through the use of the tap staggering technique and to validate the estimated results with site trial data. The operation of parallel transformers (at primary substations) with staggered taps can provide a means of absorbing reactive power. The aggregated reactive power absorption from many primary substation transformers could be used to mitigate the high voltage issues in the transmission grid during periods of low demand.

The objective of WP2-Part B is to carry out network reactive power absorption capability studies by developing accurate Extra High Voltage (EHV) network models with real load profiles. In addition, WP2-Part B has estimated the demand reduction capability of the modelled EHV network using the load models from WP1.

First, WP2-Part B has proposed a closed-loop control system for the tap staggering operation. The system consists of an EHV network model, the state estimation for the network observability of unmonitored substations and the tap stagger control method. The control method can determine how many transformers and staggered taps should be used according to the requirement of reactive power absorption.

The main achievements consist of three parts: (i) network modelling and conversion; (ii) reactive power absorption capability studies and validation of trial data; (iii) demand reduction capability study of the modelled EHV network. The details of the research studies are listed as follows.

(i) Two representative sub-networks have been selected from the original EHV network model provided by Electricity North West. One is the South Manchester network with 102 buses and the other is the Stalybridge network with 222 buses. Each network model consists of a 132kV Grid Supply Point (GSP) and its downstream 33kV networks. In order to carry out time-series load flow studies, both networks have been converted from the original IPSA model to the OpenDSS model. The average error of the bus voltages calculated from the IPSA and OpenDSS models is around 0.01%.

(ii) For both the South Manchester and the Stalybridge network models, reactive power absorption capability studies have been carried out with fixed load demands. The studies have investigated the VAr absorption observed at the GSPs by applying the tap staggering technique to primary substation transformers. With the linear approximation method, the average reactive power absorption per primary substation (due to tap stagger) has been estimated. The main findings are summarised below.

- An average *Q* absorption of 0.06 MVAr and power loss of 0.004 MW per primary substation for Stagger = 1 (i.e. one tap up for one transformer and one tap down for the other).
- An average *Q* absorption of 0.23 MVAr, 0.51 MVAr and 0.89 MVAr per primary substation for Stagger = 2, 3, and 4, respectively. The corresponding power losses introduced by tap stagger are 0.01 MW, 0.03 MW and 0.05 MW per primary substation, respectively.

Furthermore, time-series reactive power capability studies have been carried out using the Stalybridge network model. The studies have investigated the reactive power absorption capability of the Stalybridge network over the 24-hour (48 × ½ hour) period in a day and in four seasons. In order to perform the time-series studies, annual load profiles for all primary substations in the Stalybridge network have been developed from site monitoring data. For each primary substation, the load profiles have been divided into four seasons. Each season has an average daily load curve with 48 points (i.e. half-hourly resolution). The key findings from the seasonal capability studies are listed as:

- With the maximum tap stagger operation of Stagger = 1 (i.e. one tap up for one transformer and one tap down for the other), the Electricity North West reactive power absorption capability is 15-18 MVAr, 15-17 MVAr, 15-19 MVAr and 16-20 MVAr in spring, summer, autumn and winter, respectively.

- With the constraint of Stagger = 2, the Electricity North West reactive power absorption capability is 59-70 MVAr, 60-68 MVAr, 59-72 MVAr and 62-75 MVAr in spring, summer, autumn and winter, respectively.
- With the constraint of Stagger = 3, the Electricity North West reactive power absorption capability is 129-156 MVAr, 134-152 MVAr, 132-159 MVAr and 131-167 MVAr in spring, summer, autumn and winter, respectively.
- For each season, the reactive power absorption has changed over the 24-hour period. This is due to the variations of network demand. When the demand level is high, the network can provide more reactive power through the use of tap stagger.
- In the simulations, all primary substations can achieve up to Stagger = 3. However, for certain network loading, several substations cannot achieve Stagger = 4 or 5, due to their physical tap position limits.

The project has also carried out site trials to validate the effectiveness of the tap staggering technique. The validations have considered the tap stagger trials at a single primary substation (Dickinson Street) and in the Stalybridge network. For the Stalybridge network, seven primary substations have been selected to implement the tap staggering simultaneously. The corresponding reactive power variations at the GSP have been monitored, and the obtained data have been compared with the simulation results. The tap stagger validation of the Dickinson Street substation indicates an error of 0.275% between the simulated and monitored VAr absorption, with Stagger = 3. For the Stalybridge network validation, the result shows an error of 3.06% between the simulated and the monitored VAr absorption, with Stagger = 3.

(iii) Finally, the demand reduction capability of the modelled Stalybridge network has been investigated. In order to carry out the demand response studies in OpenDSS, the exponential load models from WP1 have been converted to *ZIP* models (i.e. combinations of constant impedance, constant current and constant power load models) using Taylor Series. Based on the analysis from WP2-Part A, the studies have only considered the voltage reduction up to 3% (i.e. equivalent to two taps down of the primary substation transformers), which will not cause low voltage problems in the downstream LV networks. The results indicate that the demand reduction capability of the Stalybridge network is 5-8 MW, 5-7 MW, 4-8 MW and 6-10 MW (with two taps down) in spring, summer, autumn and winter, respectively.

The studies and analyses presented in this report have quantified the reactive power absorption capability of the Electricity North West's network through the use of tap stagger. The outcomes have confirmed that the tap staggering technique has the potential to increase the reactive power demand drawn from the transmission grid. Further studies may consider the development of a real-time control system to demonstrate the effectiveness of the tap staggering method on mitigating transmission system high voltages.

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1 Introduction

The power sector decarburisation is expected to result in more distributed generation (DG) with renewable resources to be connected into distribution networks. However, during periods of low demand, the network voltages may exceed the acceptable limits due to the growing DGs. The overvoltage problems have also occurred in the transmission system [1], [2]. The main reasons include the development of underground cables in distribution and transmission networks, the decommissioning of coal generators in specific areas and the reduction in reactive power demand. Distribution network operators may therefore provide reactive power supports as ancillary services to help National Grid balance the reactive power flow in the transmission system.

As a part of the Electricity North West CLASS project, this work package (WP2-Part B) presents a reactive power management method, which implements the tap staggering operation on the existing parallel transformers at primary substations, to provide reactive power absorption services to support the transmission system during periods of low demand. The operation of two parallel transformers with different (or staggered) tap positions will introduce a circulating current around the pair. Due to the inductance of the parallel transformers, the circulating current will draw more reactive power demand from the upstream network. Considering the losses and overloading of the parallel transformers, the number of staggered taps should be limited (e.g. suggested up to 4 taps up for one transformer and 4 taps down for the other). The tap stagger constraint will limit the reactive power absorption capability from each pair of parallel transformers. However, if considering a large number of parallel transformers in the distribution network, the aggregated VAr absorption within the distribution network could be sufficiently high to support the transmission system.

1.1 Project objective

The objective of WP2-Part B is to investigate and quantify the reactive power absorption capability of the Electricity North West EHV network by applying the tap staggering technique to primary substations. The detailed tasks are listed below.

- Modelling of EHV distribution networks, from 132kV GSPs down to 33kV primary substations with parallel transformers.
- Estimation of the reactive power absorption capability of the modelled EHV networks with fixed load demands.
- Assessment of the reactive power absorption capability of the EHV networks on an hourly, daily and seasonal basis.
- Validation of the tap staggering technique using site trial data.

In addition, WP2-Part B has estimated the demand reduction capability of the modelled EHV network using the load models from WP1.

1.2 Report outline

This report first presents the methodology of using the tap staggering technique to increase reactive power consumption of distribution networks in Section 2. Section 3 then describes the modelling of two representative sub-networks from the original EHV network model provided by Electricity North West. Based on the developed network models, Section 4 carries out the reactive power absorption capability studies considering the networks with fixed load demands or at various load levels. The studies aim to assess the EHV network VAr absorption capability over the 24-hour (48 × ½ hour) period in a day and in four seasons. In addition, Section 4 presents the validation of the tap staggering site trial data against the simulation results. Section 5 investigates the demand reduction capability of the modelled EHV network. Finally, section 6 concludes this report and summarises the key outcomes from the work carried out.

2 Methodology

The methodology of using the tap staggering technique to deliver reactive power absorption services is illustrated in Figure 2-1. It consists of three parts: (i) an EHV network model, (ii) state estimation for the network observability, and (iii) the tap stagger control method.

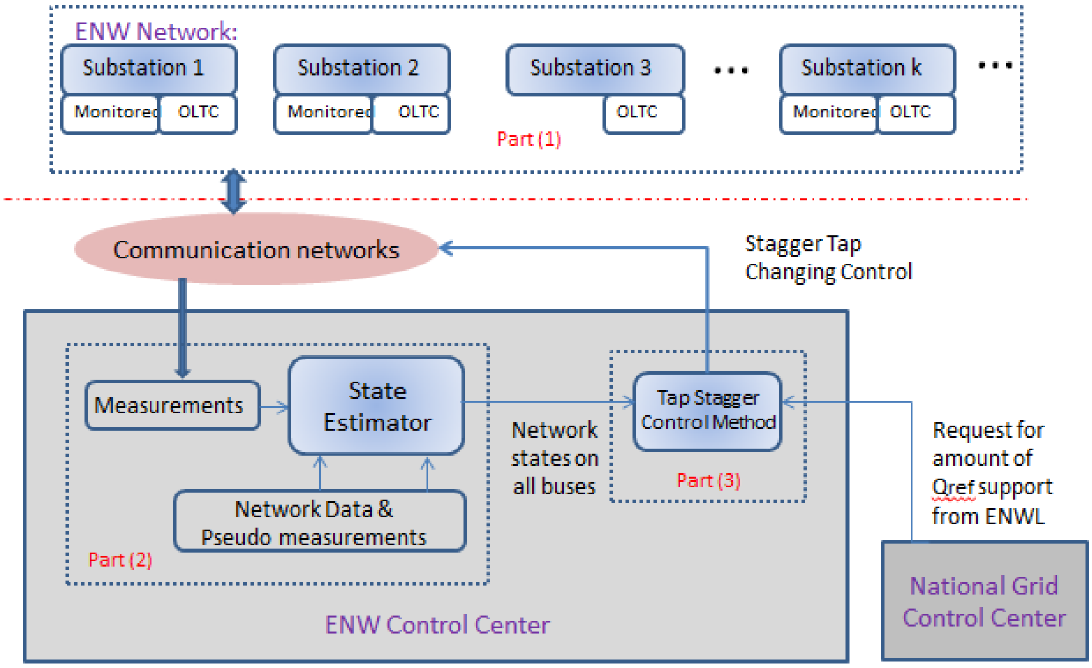


Figure 2-1: Methodology of the tap staggering operation and control in a distribution network

Part 1 at the top of Figure 2-1 represents an EHV network. In the network, some substations are monitored and have communication channels linked to the control centre. However, most substations are unmonitored, therefore, the substation operating conditions, e.g. voltage and power flow, are unknown. To achieve the observability for these unmonitored substations, the distribution state estimator (as Part 2 shown in Figure 2-1) is used to estimate the network operating conditions. The state estimation results will be accessed by the tap stagger control method as Part 3 shown in Figure 2-1. The control method will determine how many parallel transformers and staggered taps will be used to provide the required VAr absorption service for the transmission grid. The details of each part are described as follows.

2.1 Tap stagger at primary substation

At electric substations, the operation of two transformers in parallel improves the security of supply. The tap changer of each transformer is usually maintained at the same position to reduce the circulating current around the pair [3]. However, if the parallel transformers are operated at different tap positions, a circulation of reactive power will occur between the transformers, resulting in a net absorption of reactive power. This operating mode is known as 'tap stagger' and is occasionally adopted in transmission systems for reactive power absorption [4], [5]. In this project, the tap staggering technique is applied to the parallel transformers at the primary substations of the Electricity North West EHV network. The aggregated VAr absorption from the distribution network could be used to help transmission systems control voltages under light-load conditions.

2.1.1 Transformer circulating current

The operation of two parallel transformers with staggered taps is illustrated in Figure 2-2. The primary windings of both transformers T_1 and T_2 are equipped with on-load tap changers (OLTCs). Initially, both OLTCs were maintained at the same positions. The tap stagger pattern is achieved by tapping down the OLTC on T_1 by N steps while tapping up the OLTC on T_2 by the same N steps. Figure 2-3 shows the equivalent circuit referred to the transformer secondary sides.

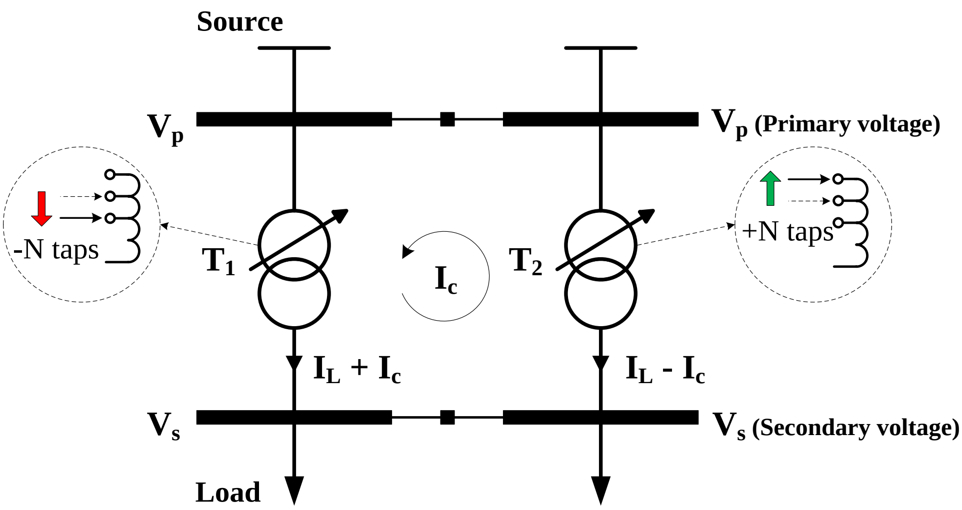


Figure 2-2: Tap staggering operation at a primary substation [6]

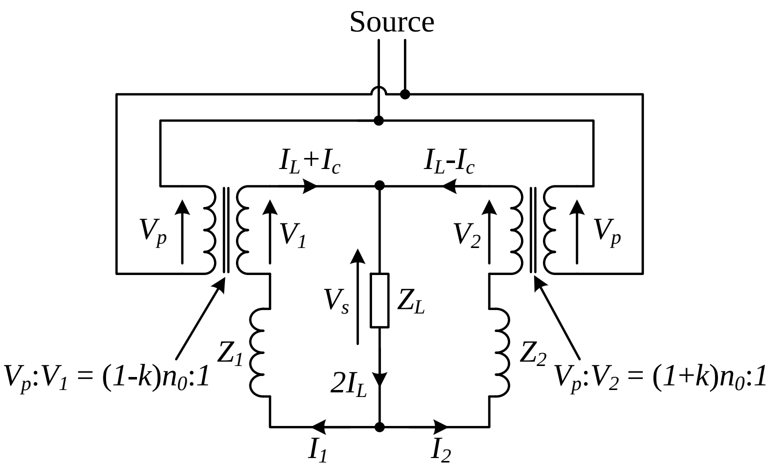


Figure 2-3: Equivalent circuit (referred to transformer secondary sides) of tap stagger [5]

Assuming both transformers have the same tap changer parameters, the primary voltage V_p referred to the secondary side of T_1 or T_2 is:

$$V_1 = V_p/[(1-k)n_0] \quad \text{Eq. 2-1}$$

$$V_2 = V_p/[(1+k)n_0] \quad \text{Eq. 2-2}$$

where n_0 denotes the initial transformer ratio and k represents an offset value (from the initial tap position) introduced by the tap stagger. As shown in Figure 2-3, Z_1 and Z_2 denote the transformer impedances referred to the secondary sides of T_1 and T_2, respectively. Z_L denotes the load impedance. For the usual case of $Z_L >> Z_1$ and Z_2, the secondary currents of transformer T_1 and T_2 can be derived as [5]:

$$I_1 \approx \frac{V_1 Z_2 + (V_1 - V_2)Z_L}{(Z_1 + Z_2)Z_L} \qquad \text{Eq. 2-3}$$

$$I_2 \approx \frac{V_2 Z_1 - (V_1 - V_2)Z_L}{(Z_1 + Z_2)Z_L} \qquad \text{Eq. 2-4}$$

Both I_1 and I_2 have a common component which is termed as the circulating current:

$$I_c = \frac{V_1 - V_2}{Z_1 + Z_2} \qquad \text{Eq. 2-5}$$

The remaining components of I_1 and I_2 are:

$$I_{L1} = \frac{V_1 Z_2}{(Z_1 + Z_2)Z_L} \qquad \text{Eq. 2-6}$$

$$I_{L2} = \frac{V_2 Z_1}{(Z_1 + Z_2)Z_L} \qquad \text{Eq. 2-7}$$

With a small value of k, $I_{L1} \approx I_{L2} = I_L$ hence $I_1 = I_L + I_c$ and $I_2 = I_L - I_c$. Due to the circulating current introduced, additional reactive power will be consumed by the transformer leakage reactances in Z_1 and Z_2.

2.1.2 Transformer secondary voltage

If both transformers have the same impedance, i.e. $Z_1 = Z_2 = Z$, the secondary voltage can be derived as [6]:

$$V_s = (I_1 + I_2)Z_L = \frac{V_1 Z + V_2 Z}{2Z} = \frac{V_p}{(1 - k^2)n_0} \qquad \text{Eq. 2-8}$$

According to Eq. 2-8, the transformer secondary voltage V_s will remain almost constant if the parallel transformers are tapped apart within a small range of k. Therefore, the voltages and demands of the downstream networks will not be affected when applying the tap staggering technique.

Note that, from Eq. 2-3, if the two transformers are tapped apart, the current through one transformer will increase and may exceed the transformer rating. However, since the tap stagger is likely to be activated when system demand is low, the initial transformer current is low. Therefore, the use of tap staggering technique is practicable, depending on the transformer capability. The circulating current created between the parallel transformers will draw more reactive power demand from the upstream network. This will help mitigate the high voltages in the upstream grid while leaving the downstream customer voltages unaffected.

2.2 Distribution state estimation

The distribution state estimation (DSE) is a mathematical minimization process used to estimate the distribution network states, e.g. bus voltage magnitudes and angles, real and reactive power. A weighted least square function is commonly adopted to formulate the state estimation as [7]:

$$\min_{\boldsymbol{x}} J(\boldsymbol{x}) = \sum_{i=1}^{N_m} \frac{[z_i^{meas} - f_i(\boldsymbol{x})]^2}{\sigma_i^2} \qquad \text{Eq. 2-9}$$

where,

$\boldsymbol{x}$	State vector that consists of network bus voltages.
N_m	Total number of measurements.
z_i^{meas}	The i^{th} measurement value.
$f_i(\boldsymbol{x})$	A function of state variables and it is used to theoretically calculate the value of the i^{th} measurement.
σ_i^2	Variance of the i^{th} measurement.

The solution of Eq. 2-9 is a set of state variables that minimises the squares of errors between the measured values and the values calculated from state variables. In other words, the DSE can generate a group of bus voltages that enables the power flow calculated in theory to match the measurements. To reduce the need of large numbers of measurements, the DSE usually takes real-time measurements at critical points in the network and combines them with pseudo measurements [8]. The pseudo measurements can be obtained from the historical load database of substation transformers.

2.3 Tap stagger control

With the state estimation, the distribution network operator (DNO) can observe the voltage and power flow changes in the entire network due to the application of tap stagger. A control method can then be developed to select the primary substation transformers and determine how many staggered taps will be used to provide the VAr absorption service (see Figure 2-1).

This project has proposed a matrix/database method to solve the tap stagger control problem. The method will first establish a network capability database by carrying out off-line load flow studies. The database will store the information of the available VAr absorption from each parallel transformer with different staggered taps and under various load conditions. The method will then search the optimal solution in the database, based on the VAr absorption requirement from Nation Grid and the state estimation results (i.e. substation voltages, power flow states and transformer tap positions). The advantage of the matrix/database method is the simplicity, and it can be easily implemented without the need of sophisticated monitoring and control systems. However, as the off-line database may not reflect the actual network operating situations, this method may only provide a basic guidance for the DNO to achieve the VAr absorption service using tap stagger.

2.3.1 **Establishment of matrix database/dashboard look up table**

The network capability database can be developed through off-line load flow studies. The studies will measure both the active and reactive power demand changes at the GSPs by applying the tap staggering technique to the downstream primary substations. The amount of the additional *Q* absorption (or *P* loss) from each primary substation mainly depends on two factors: (i) the primary substation demand level, and (ii) the number of staggered taps between the two transformers. Therefore, the studies will start with the investigation of one pair of primary substation transformers with different staggered taps and at various load levels. Then the studies will reset the parallel transformers with the same tap position and move to another primary substation. The process will be repeated for all primary substations in the network. Table 2-1 gives an example of the obtained off-line database.

Table 2-1: Off-line database of the additional *Q* absorption and *P* variation measured at the GSP with the tap stagger applied at primary substations

NO. of primary sub	1							
Tap Stagger[a]	1		2		3		4	
Loading (pu)	Q KVAr	P kW	Q KVar	P kW	Q KVAr	P kW	Q KVAr	P kW
….	-	-	-	-	-	-	-	-
1.2	-	-	-	-	-	-	-	-
1.1	61.46	2.29	246.08	9.16	554.63	20.64	988.39	36.77
1	60.20	2.23	241.03	8.93	543.24	20.12	968.21	36.01
0.9	59.35	2.21	237.62	8.83	535.54	19.90	954.31	35.46
0.8	58.75	2.19	235.23	8.75	530.14	19.72	944.67	35.13
….	-	-	-	-	-	-	-	-
NO. of primary sub	2							
Tap Stagger[a]	1		2		3		4	
Loading (pu)	Q kVAr	P kW	Q KVAr	P kW	Q kVAr	P kW	Q kVAr	P kW
….	-	-	-	-	-	-	-	-
1.2	-	-	-	-	-	-	-	-
1.1	58.80	3.89	235.78	15.40	531.63	34.61	947.54	61.63
1	57.72	3.85	231.43	15.28	521.79	34.36	929.95	61.20
0.9	57.00	3.84	228.51	15.27	515.19	34.35	918.14	61.22
0.8	56.51	3.83	226.49	15.26	510.61	34.36	909.93	61.25
….	-	-	-	-	-	-	-	-
NO. of primary sub	3							
Tap Stagger[a]	1		2		3		4	
Loading (pu)	Q kVAr	P kW	Q KVAr	P kW	Q kVAr	P kW	Q kVAr	P kW
….	-	-	-	-	-	-	-	-
1.2	-	-	-	-	-	-	-	-
1.1	47.78	5.83	195.02	21.88	442.17	48.28	790.02	85.18
1	46.91	5.74	191.09	21.75	432.99	48.14	773.35	85.09
0.9	46.35	5.68	188.48	21.71	426.81	48.21	762.07	85.35
0.8	45.99	5.62	186.69	21.67	422.51	48.26	754.14	85.58
….	-	-	-	-	-	-	-	-
NO. of primary sub	4,5,6…11							
Tap Stagger[a]	1		2		3		4	
Loading (pu)	Q kVAr	P kW	Q KVAr	P kW	Q kVAr	P kW	Q kVAr	P kW
….	-	-	-	-	-	-	-	-

a. Stagger = n (n= 1, 2, 3 and 4) indicates that one transformer tap position will increase by n steps and the other will decrease by n steps.
b. Considering the transformer rating and OLTC tap position limit, the maximum permitted tap stagger is set to 4.
c. The study is based on the Stalybridge network model, which is described in Section 3.

2.3.2 Matrix database/dashboard lookup table search method

For a radial distribution network, the power flows of primary substations are usually independent of each other. Therefore, when the network needs to provide the VAr absorption service, the DNO can estimate the total VAr absorption by summing up the MVArs from each primary substation according to the off-line capability database. An effective search method should be developed to determine which primary substations and how many staggered taps will be used. Figure 2-4 illustrates the flow chart of the proposed search method.

The method requires the inputs of state estimation results (e.g. tap positions and power flows) and the required VAr absorption amount from the transmission grid. The tap positons of each pair of parallel transformers can be used to check if the pair has available headroom for the tap staggering operation. The constraint of staggered taps should be considered to prevent transformers from overloading. To minimise the network loss and the number of tap switching operations introduced, the tap stagger control can adopt various algorithms to search the optimal solution in the database, such as the branch-and-bound method [9] and the genetic algorithm [10].

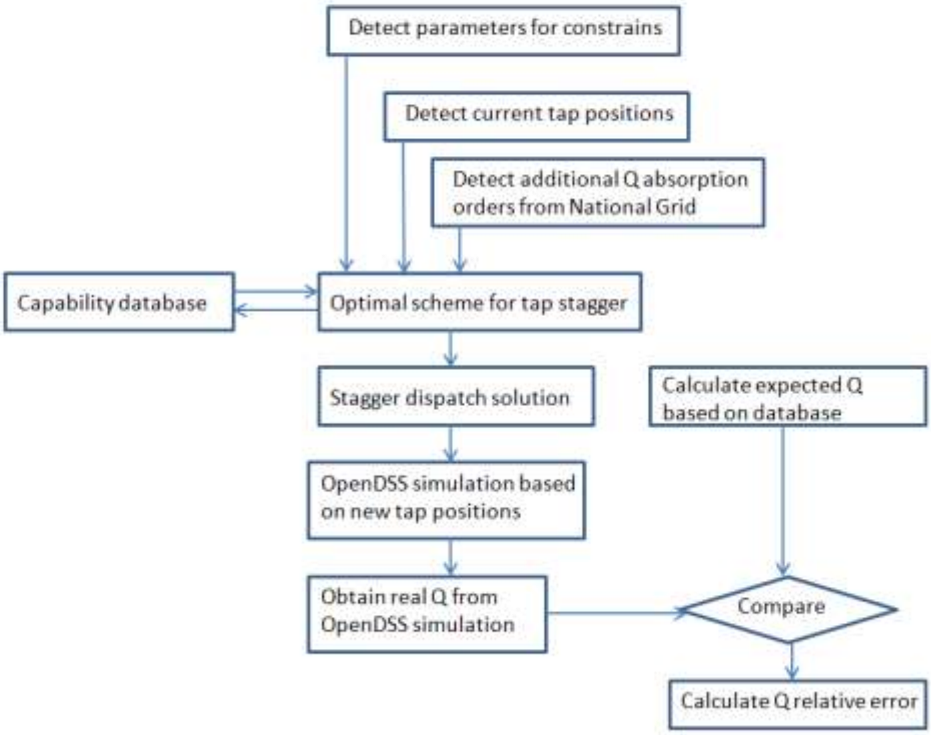


Figure 2-4: Flow chart of the tap stagger search method

3 Network Selection and Modelling

In the CLASS project, Electricity North West has provided the university with its entire EHV network model, which includes the 132kV grid supply points (GSPs) and the overall downstream 33kV networks. The EHV network has been modelled using the IPSA software, which does not provide automatic time-series load flow studies. As WP2-Part B aims to assess the network VAr absorption capability on different hours, days and seasons across a year, the IPSA model has been converted using another network modelling tool, i.e. the OpenDSS [11] for this project. The OpenDSS is an open source simulation tool for power flow calculations, harmonics analyses and fault studies in distribution systems. Compared with the IPSA, the OpenDSS provides more comprehensive load models and can carry out time-series (e.g. daily and yearly) simulations with load profiles. In addition, OpenDSS power flow results can be easily accessed by other software, e.g. MATLAB.

According to the EHV network model provided by Electricity North West, the distribution system has 18 grid supply points (GSPs). Therefore, the system can be divided into 18 sub-networks. To study the EHV network more efficiently, WP2-Part B has selected two representative sub-networks and converted them from the IPSA models to the OpenDSS models. The details are described below.

3.1 Sub-network selection

The entire EHV network model of Electricity North West is shown in Appendix 1. Figure 3-1 illustrates the network structure with different voltage levels.

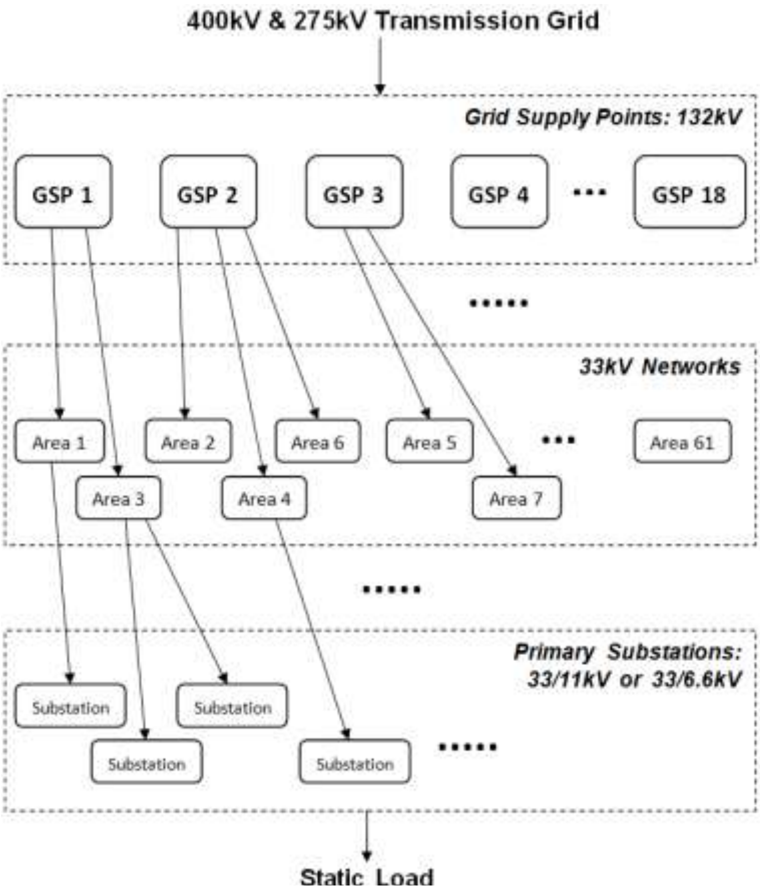


Figure 3-1: EHV network model structure

As shown in the figure, the distribution system is configured as a radial network and the main source is from the transmission grid at 400kV and 275kV voltages. The distribution system operates at four different voltage levels, i.e. 132kV, 33kV, 11kV and 6.6kV. From the GSPs, electricity is distributed throughout the 33kV networks. In each 33kV load area, there is at least one primary substation (i.e. 33/11 kV or 33/6.6 kV) connected. The downstream 11kV or 6.6kV networks are modelled as constant power loads and connected to the secondary sides of primary substations.

Note that the overall EHV network shown in Figure 3-1 consists of 18 GSPs and 61 load areas. There are total 354 primary substations located throughout the 33kV load areas. Each primary substation usually has two parallel transformers equipped with OLTCs. The tap staggering technique has been applied to the primary substation transformers in the CLASS project.

To study the network capability efficiently, WP2-Part B has selected two sub-networks from the originally provided EHV network model. They are (i) the South Manchester network, and (ii) the Stalybridge GSP network. The South Manchester network model includes the 132kV South Manchester GSP and a part of the downstream 33kV networks (see Appendix 2). The model represents a small-scale distribution system. However, the Stalybridge network model represents a large-scale distribution system, which consists of the Stalybridge GSP and its entire downstream 33kV networks (see Appendix 3). The details of the two sub-network models are given in Table 3-1.

Table 3-1: Parameters of two selected sub-network models

	South Manchester Network	Stalybridge Network
GSP name	South Manchester GSP	Stalybridge GSP
No. of BSP	2	6
Names of BSP	Moss Nook, Stretford	Buxton, New Mills, Heyrod, Stuart Street, Droylsden, Hyde
No. of primary substations	11	28
No. of transformers	33	76
No. of distributed generators	5	0
Total power rating at GSP	178 MW 88 MVAr	434 MW 236 MVAr
Average power factor at GSP	89.56%	87.88%
Total No. of buses	102	222

According to the table, the South Manchester network has two bulk supply points (BSPs), 5 distributed generators and 11 primary substations. The Stalybridge network has 6 BSPs, 28 primary substations and no distributed generators connected. As described before, the South Manchester network has been partly modelled to represent a small-scale network (e.g. with rating of 178 MW and 88 MVAr) with DGs connected. The Stalybridge network is a large-scale network (e.g. with rating of 434 MW and 236 MVAr) without DGs connected. Note that the South Manchester network model has one CLASS-trial primary substation, where the CLASS techniques (e.g. demand reduction or tap stagger) have been applied. The Stalybridge network model has 7 CLASS sites.

3.2 Network conversion

The originally provided EHV network has been modelled in IPSA, which is for network design and planning purposes. However, WP2-Part B focuses on assessing the network reactive power absorption capability over different time periods, which requires automatic time-series load flow studies with various load profiles. Therefore, the two selected sub-networks have been converted from the IPSA models to the OpenDSS models. The flow chart of the network conversion is illustrated in Figure 3-2.

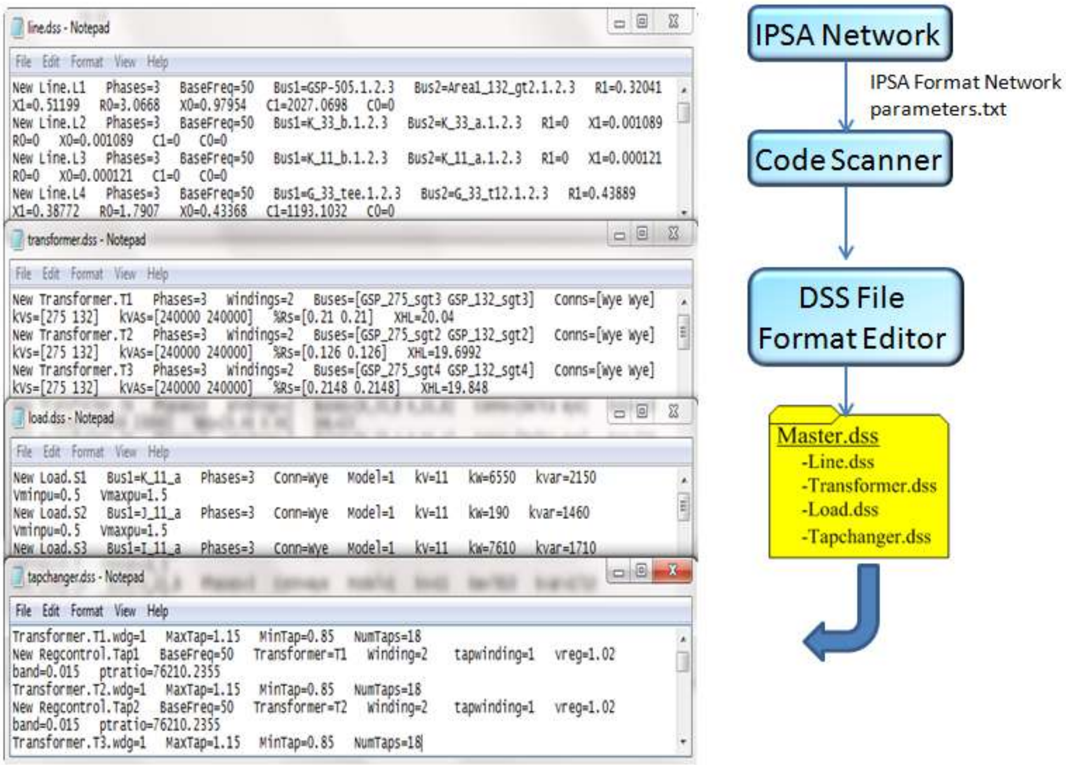


Figure 3-2: Flow chart of IPSA to OpenDSS network model conversion

First, the parameters of the selected sub-network in the IPSA model were extracted and saved to a text file. A MATLAB-based code scanner was then developed to automatically convert the text file into the OpenDSS network modelling scripts. Finally, the OpenDSS software could perform load flow studies based on the converted modelling scripts.

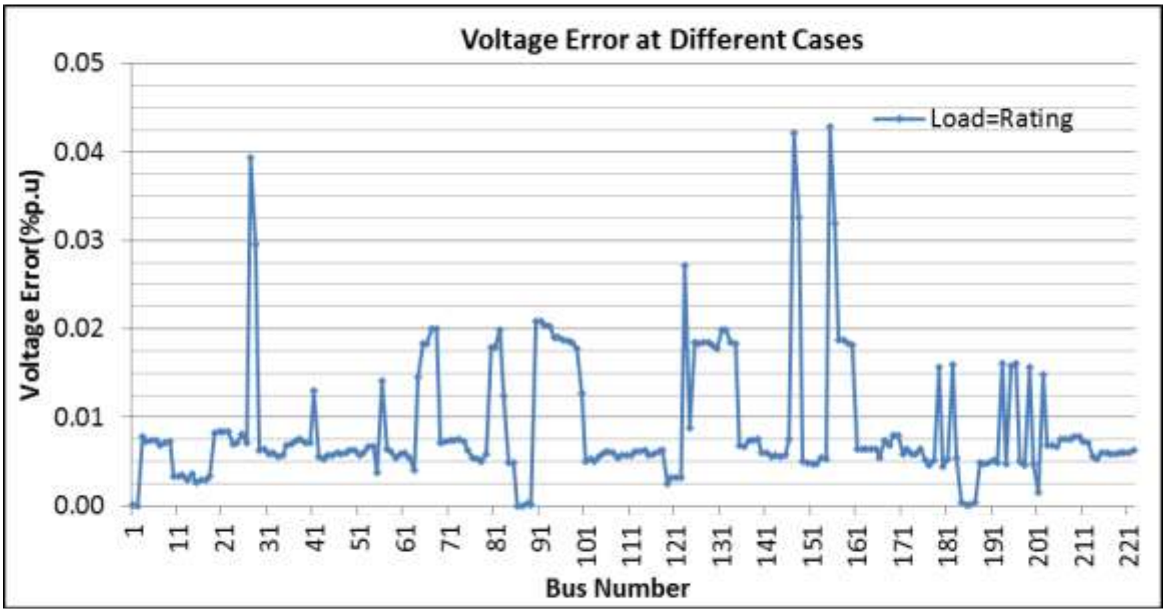
3.3 Testing and validation of the converted sub-network

The converted network models have been validated though the comparison of the bus voltages calculated between the IPSA and OpenDSS models. This section presents the validation of the Stalybridge network model that consists of more buses, lines and transformers. The validation of the South Manchester network is given in Appendix 4.

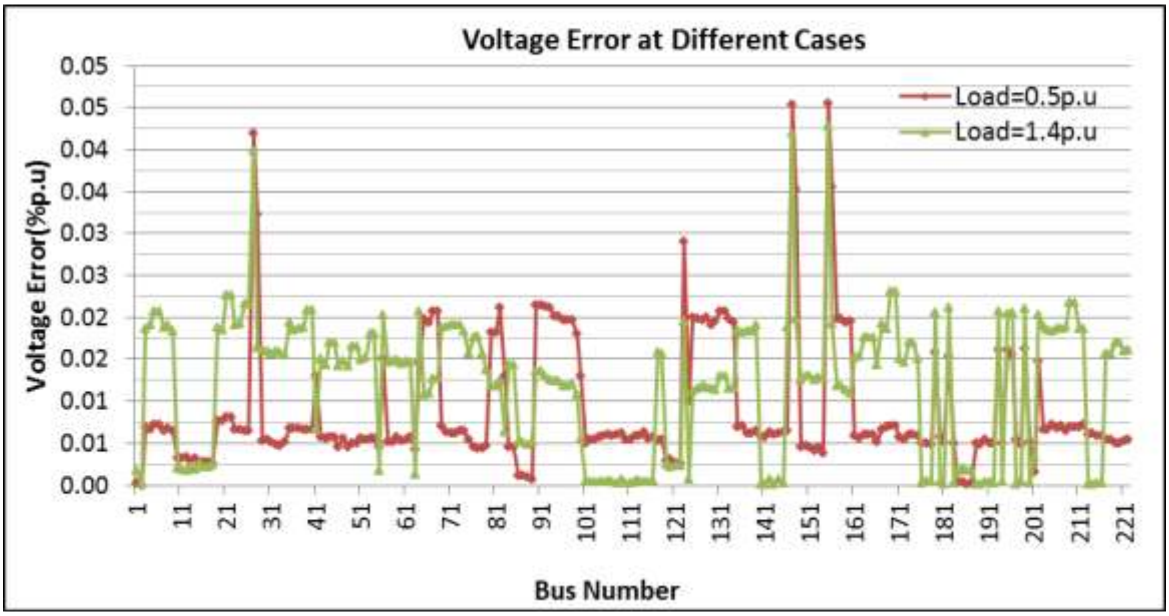
3.3.1 Network voltage comparison without AVC

Initially, the Stalybridge network model has been tested without enabling the Automatic Voltage Control (AVC) relay to control the transformer tap positions. The load flow studies have been performed under different load conditions: (i) with 1.0 pu load, (ii) with 0.5 pu load and (iii) with 1.4 pu load. The errors between the bus voltages calculated from the OpenDSS model and the IPSA model are indicated in Figure 3-3.

As shown in Figure 3-3(a), the maximum and minimum voltage differences between the OpenDSS and IPSA Models are 0.0429% and 0.00001%, respectively. The average error over all bus voltages is 0.00888%, and the standard deviation is 0.00708%. The voltage differences under the three load conditions are summarised in Table 3-2. The results indicate that the voltage differences between the converted OpenDSS model and the original IPSA model are very small (e.g. less than 0.05%), which proves the network conversion is correct.



(a) Stalybridge network under the rated load condition



(b) Stalybridge network under 0.5 pu or 1.4 pu load conditions

Figure 3-3: Bus voltage differences between the OpenDSS and IPSA network models

Table 3-2: Statistical analysis result for the bus voltage differences

Network loading	1.0 pu	0.5 pu	1.4 pu
Mean value (%)	0.00888	0.00887	0.01193
Standard deviation (%)	0.00708	0.00770	0.00831
Maximum value (%)	0.04290	0.04546	0.04285
Minimum value (%)	0.00001	0.00000	0.00002

3.3.2 Network voltage comparison with AVC

The Stalybridge network has been tested again by enabling the AVC relays to control the transformer tap positions under the rated network load condition. Figure 3-4 illustrates the voltage differences between the OpenDSS and IPSA models.

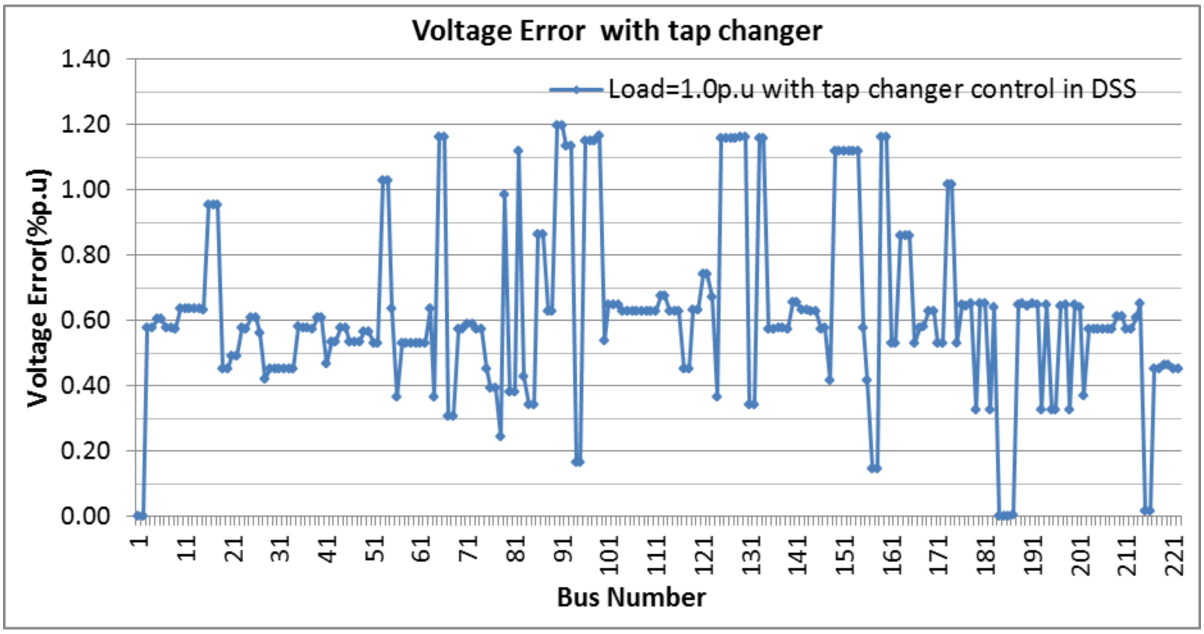
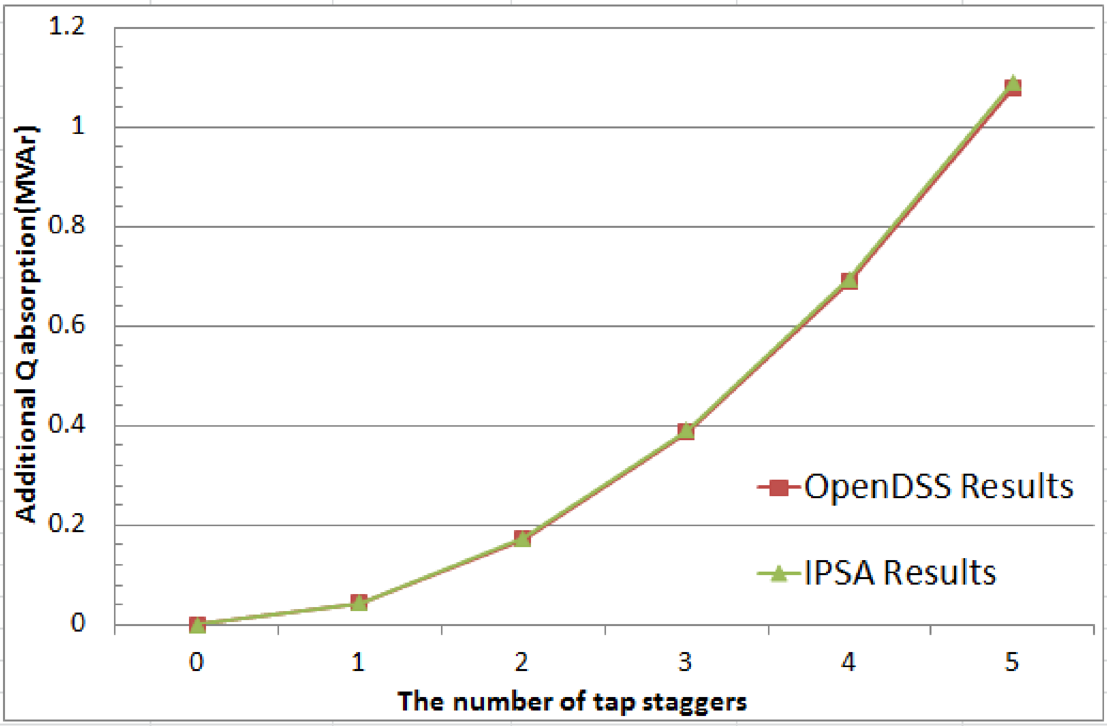


Figure 3-4: Bus voltage validation result with AVC applied

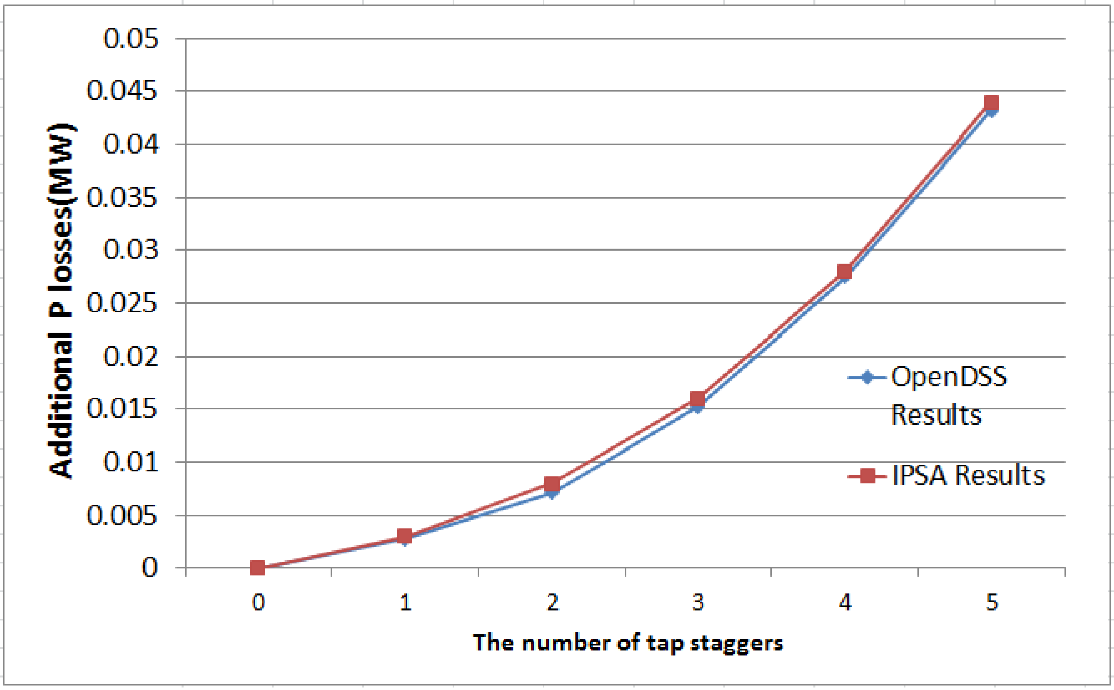
As shown in the figure, the maximum and minimum voltage differences are 1.197% and 0.00001%, respectively. The average voltage difference for all buses is 0.618%. Comparing with the result in Figure 3-3(a), the average voltage difference is higher than the case when AVC was disabled (i.e. with an average of 0.00888%). This is due to the tap changer control introduced. When running the load flow analysis, AVC relays would adjust the tap positions to maintain the bus voltages within the pre-defined deadbands. According to the default deadbands specified in OpenDSS and IPSA, the tap positions may be adjusted differently, resulting in different solutions. Nevertheless, the result indicates an average voltage difference of 0.618%, which is relatively small when comparing to the 1% measurement error of most measurement devices.

3.3.3 *Q* absorption and *P* loss validation with tap stagger

In this study, the tap staggering technique has been applied to a pair of primary substation transformers at the Buxton load area of the Stalybridge network model. The parallel transformers are 33/11 kV transformers with the names of ‘Waters_33_t11/t12’ and ‘Waters_11_a/b’, respectively. The total rated load connected to the transformer secondary side (11kV) is 7.12 MW and 3.24 MVAr. Figure 3-5 plots the additional *Q* absorption and *P* losses of the parallel transformers with different staggered taps. In the figure, for instance, Stagger =1 indicates that one transformer tap position will increase by one tap step and the other will decrease by one tap step. Table 3-3 also summarises the additional *Q* absorption and *P* losses calculated from the OpenDSS and IPSA models.



(a) Additional reactive power absorption of two parallel transformers due to tap stagger



(b) Additional active power losses of two parallel transformers due to tap stagger

Figure 3-5: Comparison of tap staggering results between the OpenDSS and IPSA models

As shown in Figure 3-5 and Table 3-3, the *Q* absorption (or *P* loss) calculated from the OpenDSS and IPSA models is very close to each other. The additional *Q* absorption introduced by tap stagger (e.g. up to 1.078 MVAr at Stagger = 5) is much larger than the additional *P* loss introduced (e.g. up to 0.043 MW at Stagger = 5). Note that Table 3-3 also indicates that the transformer secondary voltage stayed almost constant when the tap stagger was applied. The same staggering tests have also been carried out for other primary transformers in the Stalybridge network model. All compassion results confirm that the converted OpenDSS model is correct and it can be used for the following reactive power absorption capability studies.

Table 3-3: Additional *Q* absorption and *P* losses of two parallel transformers with tap stagger

33/11kV 23MVA Parallel Transformers Load at Rating 7.12MW 23MVAr						
Tap Stagger Amount	Additional Q Absorption(MVAr)		Additional P Loss(MW)		Voltage Variation (p.u.)	
	OpenDSS	IPSA	OpenDSS	IPSA	OpenDSS	IPSA
0	0	0	0	0	0	0
1	+0.0428	+0.043	+0.0028	+0.003	+0.00020	+0.00019
2	+0.1716	+0.174	+0.0071	+0.008	+0.00066	+0.00062
3	+0.3871	+0.390	+0.0152	+0.016	+0.00589	+0.00129
4	+0.6886	+0.695	+0.0275	+0.028	+0.00224	+0.00219
5	+1.0783	+1.088	+0.0432	+0.044	+0.00337	+0.00333

4 Network Reactive Power Absorption Capability Studies

4.1 Introduction

This section presents the network reactive power absorption capability studies by applying the tap staggering technique to primary substations. The studies first concentrate on assessing the average VAr absorption capabilities of the modelled EHV networks with fixed load demands. To carry out time-series capability studies, load profiles are established for monitored substations using site measurements. In addition, a load profile estimation method is developed for unmonitored substations. With the developed load profiles, load flow studies are then carried out to quantify the 24-hour (48 × ½ hour) network VAr absorption capabilities in four seasons. Based on the results, the reactive power absorption capabilities of the entire Electricity North West network and the GB distribution network are also estimated. Finally, the tap staggering simulation results are compared with the site trial data to validate the effectiveness of the tap staggering technique. The validations include the tap stagger trials carried out at a single primary substation (Dickinson Street) and in the Stalybridge network.

4.2 Reactive power absorption capability study with fixed load

As described in Section 3, WP2-Part B has developed two EHV network models in OpenDSS, which are the South Manchester network (see Appendix 2) and the Stalybridge network (see Appendix 3). They both include a 132kV GSP and the downstream 33kV networks (as the structure shown in Figure 3-1). This section presents the initial reactive power absorption capability studies for the two networks considering the network loads are fixed at their default rated values. The studies aim to provide a general insight into the average VAr absorption capability per primary substation.

4.2.1 Methodology and test procedures

Load flow studies have been carried out to calculate the reactive and active power demand changes (at the GSP) introduced by the tap staggering operation of primary substation transformers. Considering the physical limits of transformer tap positions, the maximum allowed number of staggered taps has been set to 4 (i.e. 4 taps up for one transformer and 4 taps down for the other). Figure 4-1 illustrates the flow chart of the test procedures. The details are summarised below:

1) Perform the initial load flow simulation in the OpenDSS network model without tap stagger. Set all primary substation transformers with Stagger = 1 and perform the load flow study. Repeat the simulation with Stagger = 2, 3, and 4, respectively. Record the *Q* and *P* demands at the 132kV GSP for all simulations.
2) Subtract the initial *Q* and *P* values (obtained without tap stagger) from the *Q* and *P* values obtained with stagger, to calculate the additional *Q* absorption and *P* loss caused by the tap stagger.
3) Take the average of the results in step (2) to represent the average *Q* absorption and *P* loss per primary substation (due to tap stagger).
4) As the network is a radial distribution network, it is assumed that the total *Q* absorption and *P* loss of the network will increase linearly with the number of primary substation transformers using tap stagger. Therefore, the *Q* absorption and *P* loss for the Electricity North West network can be estimated by multiplying the results in step (3) with the total number of primary substations in the Electricity North West network.

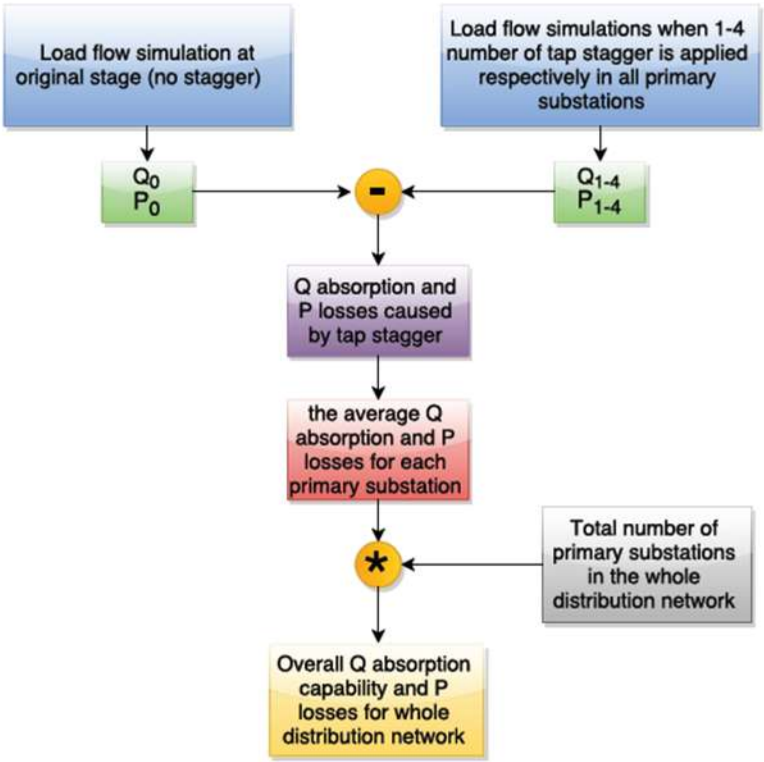


Figure 4-1: Flow chart of the test procedures for *Q* capability study with fixed load

4.2.2 Test results and analysis

The test procedures described above have been applied to the South Manchester and the Stalybridge network models. The results are indicated in Table 4-1 and Table 4-2, respectively.

Table 4-1: Additional *Q* absorption and *P* loss of the South Manchester network with stagger

South Manchester GSP subnetwork consisting of 11 pairs of parallel transformers and 102 load buses					
Allowed Maximum Stagger Amount	original	1	2	3	4
P at 400kV Point (MW)	164.6614	164.698	164.801	164.971	165.208
Q at 400kV Point (MVAr)	10.1624	10.7661	12.585	15.6134	19.8431
Additional P losses (MW)	0	0.0364	0.1397	0.3096	0.5462
Additional Q absorption (MVAr)	0	0.6037	2.4226	5.451	9.6807
P losses per primary sub(MW/Sub)	0	0.00331	0.0127	0.028145	0.04965
Q absorbed per primary sub(MVAr/Sub)	0	0.05488	0.22024	0.495545	0.88006

As shown in Table 4-1, the additional *Q* absorption for all 11 pairs of parallel transformers with Stagger = 1 is 0.6037 MVAr. The reactive power absorption increases to 9.68 MVAr for all parallel transformers with Stagger = 4 (i.e. 4 taps up for one transformer and 4 taps down for the other). In terms of the Stalybridge network model, Table 4-2 indicates that the *Q* absorption of the total 28 pairs of parallel transformers with Stagger = 1 is 1.744 MVAr. The reactive power absorption increases to 25.18 MVAr for all parallel transformers with Stagger = 4. From Table 4-1 and Table 4-2, the *P* losses introduced by the tap stagger are generally 17 times smaller than the *Q* absorption created.

Table 4-2: Additional *Q* absorption and *P* loss of the Stalybridge network with stagger

Stalybridge GSP subnetwork consisting of 28 pairs of parallel transformers and 222 load buses					
Allowed Maximum Stagger Amount	original	1	2	3	4
P at 400kV Point (MW)	433.64	433.746	434.041	434.5247	435.143
Q at 400kV Point (MVAr)	208.664	210.408	215.356	223.4832	233.842
Additional P losses (MW)	0	0.1057	0.401	0.8847	1.5029
Additional Q absorption (MVAr)	0	1.744	6.6923	14.8192	25.1776
P losses per primary sub (MW/Sub)	0	0.00378	0.01432	0.031596	0.05368
Q absorbed per primary sub(MVAr/Sub)	0	0.06229	0.23901	0.529257	0.8992

Assuming all primary substation transformers (i.e. a total of 354 pairs) in the Electricity North West network can contribute to the reactive power absorption service, the total VAr absorption capability has been estimated using the linear approximation (as presented in Figure 4-1). Table 4-3 shows the result, based on the South Manchester network study.

Table 4-3: Estimated *Q* absorption capability of the Electricity North West network based on the South Manchester network study

Estimated Q Absorption Capability for the whole ENWL network based on South Manchester GSP subnetwork study					
Allowed Maximum Stagger Amount	original	1	2	3	4
P loss across ENWL(MW)	0	1.17142	4.4958	9.963491	17.5777
Q Capability across ENWL(MVAr)	0	19.4282	77.9637	175.4231	311.543

In addition, Table 4-4 indicates the estimated reactive power absorption capability of the Electricity North West network based on the Stalybridge network study.

Table 4-4: Estimated *Q* absorption capability of the Electricity North West network based on the Stalybridge network study

Estimated Q Absorption Capability for the whole ENWL network based on Stalybridge GSP subnetwork study					
Allowed Maximum Stagger Amount	original	1	2	3	4
P loss across ENWL(MW)	0	1.33635	5.06979	11.18514	19.001
Q Capability across ENWL(MVAr)	0	22.0491	84.6098	187.357	318.317

From Table 4-3 and Table 4-4, the results obtained from the two network models are close to each other, although the two networks have different sizes and loading conditions. By taking the average of the two network study results, Table 4-5 shows the average VAr absorption capability of the Electricity North West network.

Table 4-5: Average *Q* absorption capability of the Electricity North West network

Averaging the Estimated Q Absorption Capability based on the Two Sub-Networks studies					
Allowed Maximum Stagger Amount	original	1	2	3	4
P loss across ENWL(MW)	0	1.25388	4.78279	10.57431	18.2893
Q Capability across ENWL(MVAr)	0	20.7387	81.2867	181.3901	314.93

Figure 4-2 plots the estimated VAr absorption capability of the Electricity North West network based on the two sub-network studies. According to the results, the average *Q* absorption capability per primary substation is 0.06 MVAr at Stagger = 1, 0.23 MVAr at Stagger = 2, 0.51 MVAr at Stagger = 3 and 0.89 MVAr at Stagger = 4. The corresponding power losses introduced by tap stagger are 0.004 MW, 0.01 MW, 0.03 MW and 0.05 MW per primary substation, respectively.

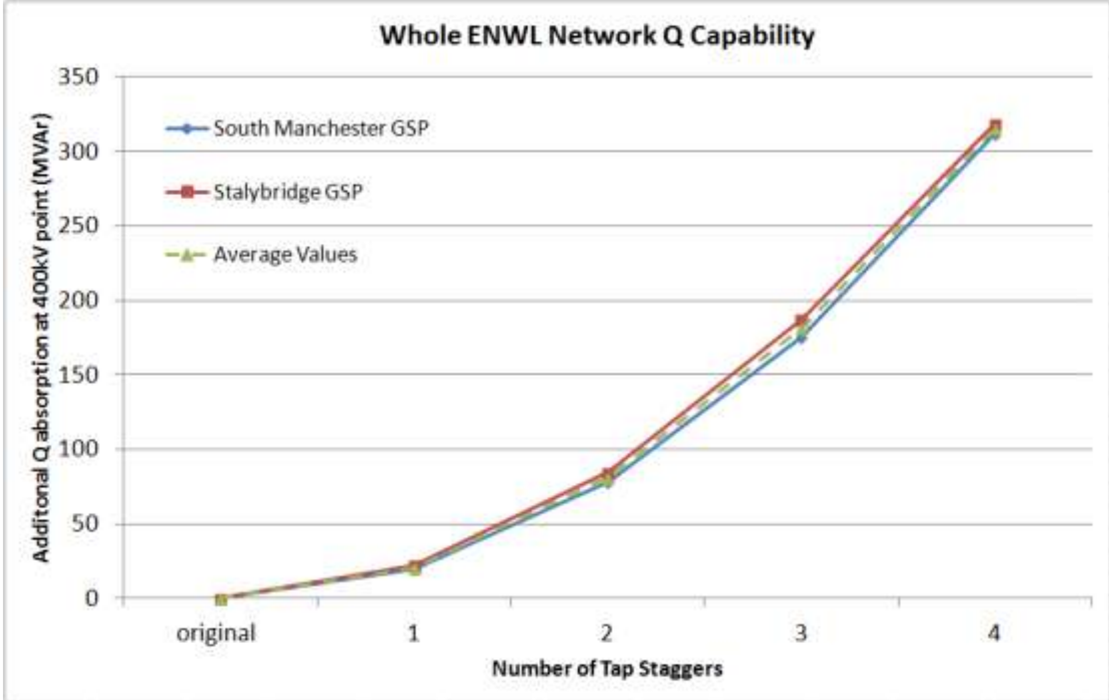


Figure 4-2: Estimated reactive power absorption capability of the Electricity North West network based on the South Manchester and Stalybridge network studies

Note that the simulations have tested the transformers with staggered taps up to 4. However, in practice, the tap position of each primary substation transformer will be determined by the load condition. In some cases, the transformer tap positions may only have limited headroom to operate with Stagger = 1 or 2. Therefore, the studies with fixed load demands may overestimate the VAr absorption capability of the Electricity North West EHV network. To refine the estimation results, Section 4.4 presents the capability studies considering the network with various load demands.

4.3 Load profile establishment

As mentioned in the previous section, the constantly changing load demands may affect the OLTC tap positions of primary substation transformers. The AVC relays may adjust the tap positions to maintain the bus voltages under various load conditions. Consequently, the available headroom for tap stagger may be different from each primary substation, resulting in different network VAr absorption capabilities during different time periods. Therefore, this section describes the establishment of load profiles for the Stalybridge network, which has demand monitoring data for all its primary substations. The developed load profiles can then be used to carry out time-series capability studies.

This section first presents the load profile modelling for the Stalybridge network based on site measurements. The profiles describe the load changes at each primary substation over the 24-hour (48 × ½ hour) period in a day and in four seasons. In addition, a method is proposed to estimate the load profiles for unmonitored substations. To validate the method, the estimated load profiles are compared with the actual profiles obtained from site data.

4.3.1 Load profile establishment for monitored substations

In the Stalybridge network, all 28 primary substations have monitoring equipment installed to measure the load demands. The data provided by Electricity North West include the active and reactive power demands for the 28 primary substations over 365 days. Each substation has 48 samples per day, i.e. one sample represents the average demand during a half hour. The direct use of the given load data would be complex and time-consuming to run load flow studies. Therefore, for each substation, the load profiles have been simplified as two daily load curves (i.e. 48 × ½ hour for weekdays and weekends) per season. The load data of 365 days have first been divided into 4 typical UK seasons, i.e. spring (March-May), summer (June-August), autumn (September-November) and winter (December-February). For each season, the data have then been categorised to weekdays and weekends. Two load profiles for each season have been developed by averaging the daily load demands in weekdays and weekends, respectively. Figure 4-3 illustrates the process of the load profile establishment.

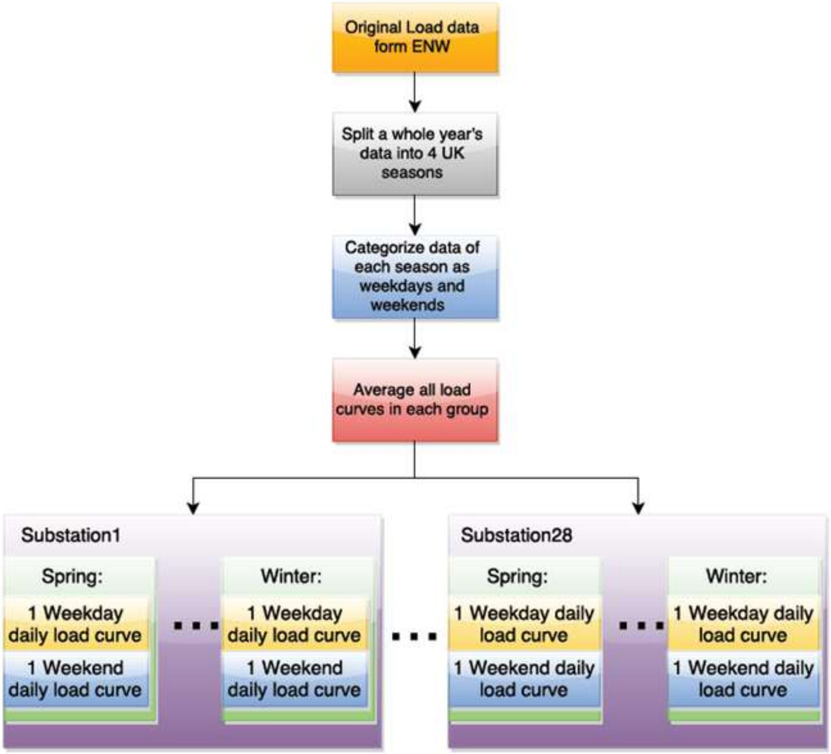


Figure 4-3: Process of load profile establishment for monitored substations

As described above, the load profiles of all 28 primary substations in the Stalybridge network have been developed using site measurements. Figure 4-4 and Figure 4-5 shows examples of the obtained load profiles for the non-domestic substation (Central Manchester) and the domestic substation (Droylsden East), respectively. The load profiles for the other 26 substations have the similar curve shapes.

Figure 4-4 shows an example of the weekday load profiles for the Central Manchester primary substation. According to the figure, winter has the highest load level of 13 MW during the peak time period (11:00-15:00), while summer has the lowest load level of 5.5 MW during the low demand period (0:00-5:00). As the Central Manchester substation mainly serves commercial customers, the load demand has increased gradually in 6:00-11:00 and decreased in 18:00-22:00. Note that the variation of the reactive power demand in a day (or in 4 seasons) is much less than that of the active power demand.

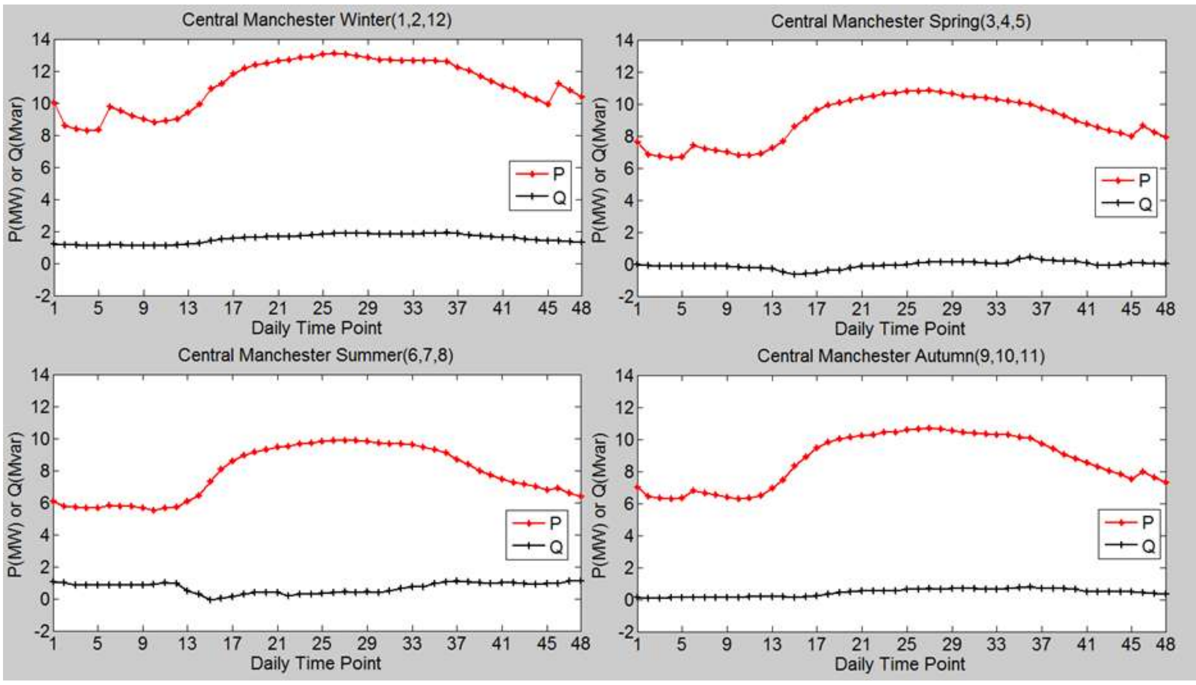


Figure 4-4: Weekday load profiles in 4 seasons for the Central Manchester substation

Figure 4-5 illustrates the weekday load profiles of 4 seasons for the Droylsden East substation, which mainly serves domestic customers. The peak load in winter (about 16.5 MW) is around three times of the lowest load in summer (about 5 MW). The period of low demand is during the midnight (from 2:00 to 5:00), and the peak time period is usually from 17:00 to 20:00.

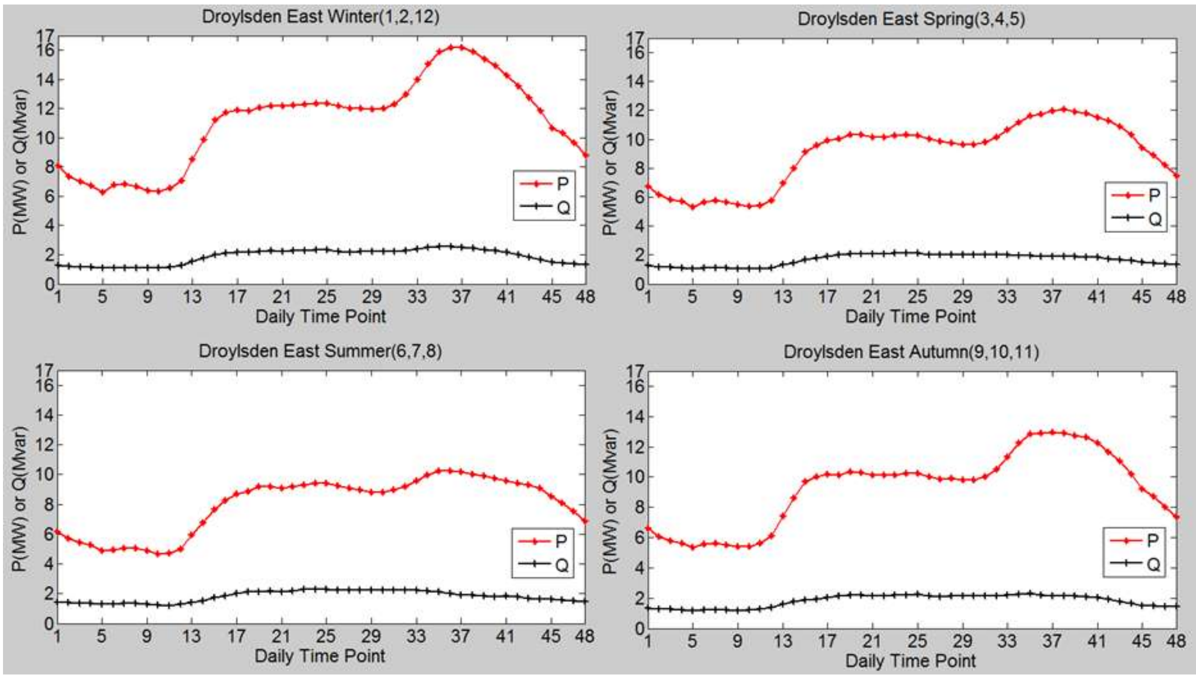


Figure 4-5: Weekday load profiles in 4 seasons for the Droylsden East substation

4.3.2 Load profile estimation for unmonitored substations

Considering the entire GB distribution system, there are thousands of primary substation transformers where the tap staggering technique can be applied. However, some substations may not have monitoring equipment installed to record the load demands. If time-series *Q* absorption capability studies need to be carried out for the network with these unmonitored substations, the corresponding load profiles should be estimated. Therefore, this section presents a load profile estimation method based on Peak Load Share (PLS). The method has been validated using the Stalybridge network model with real measurements. Figure 4-6 shows the procedure to estimate the load profiles for unmonitored substations.

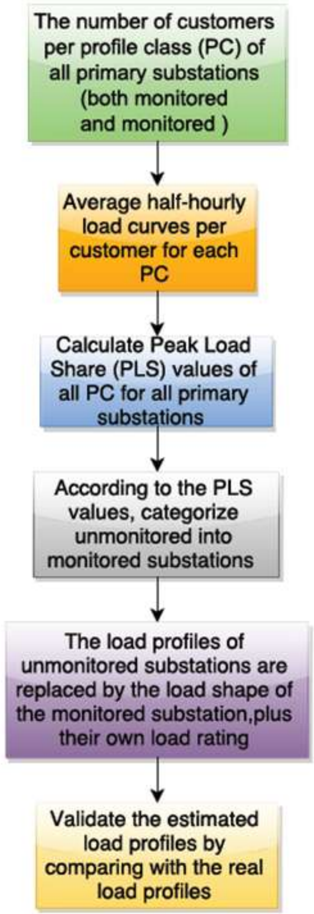


Figure 4-6: Procedure of load profile estimation

The procedure can be divided into 5 steps. First, the customers served by a primary substation can be classified into 8 generic profile classes (PCs). Each PC has an average daily load curve based on the energy consumption data provided by Electricity North West. According to the total number of customers, an aggregated load profile can be obtained for each PC. Consequently, for each substation, the Peak Load Share (PLS) value of each PC can be calculated based on the aggregated PC load profiles. According to the PLS values, the load curve of an unmonitored substation can be represented using the load curve of the monitored substation, which has the closest PLS values to the values of the unmonitored substation. The details of each step are described as follows.

4.3.2.1 Customer profile class

The 8 generic Profile Classes (PCs) are used to represent large populations of similar customers. PC1 and PC2 represent domestic customers, and the other PCs represent non-domestic customers.

Electricity North West has provided the university with the data indicating the number of customers per PC connected to their primary substations. Table 4-6 shows the number of customers for the primary substations in the Stalybridge network. This information indicates the composition of the customers served by each primary substation.

Table 4-6: Number of customers per PC for all primary substations in the Stalybridge network

Primary name - LTDS	Primary peak 2012/13 (MW)	Primary peak 2012/13 (MVAr)	Custs in PC1	Custs in PC2	Custs in PC3	Custs in PC4	Custs in PC5	Custs in PC6	Custs in PC7	Custs in PC8
ARDWICK	5.37	1.74	2,723	258	309	67	17	18	11	10
BRADFORD	11.89	3.95	3,378	190	272	43	23	16	7	18
DROYLSDEN EAST	17.23	5.30	11,476	664	392	98	17	11	7	14
DENTON EAST	15.06	4.21	9,240	383	416	116	12	19	8	9
DENTON WEST	15.25	3.83	7,731	454	310	67	12	7	4	6
OPENSHAW	15.04	4.94	7,723	317	399	80	13	18	7	9
STUART ST	13.35	5.55	4,622	393	116	12	4	5	3	5
SNIPE	15.45	5.61	5,011	553	154	33	10	3	3	5
EASTLANDS	8.87	1.89	2,165	850	174	28	11	8	4	4
CENTRAL MANCHESTER	14.09	4.63	680	937	440	77	15	22	19	36
MONSALL	2.67	0.88	78	1	0	0	0	0	0	0
QUEENS PARK	15.35	5.56	7,651	269	247	53	20	10	3	13
HYDE	16.13	5.99	8,233	505	670	141	15	14	3	9
TAME VALLEY	20.16	0.42	9,541	628	440	124	15	15	5	5
HEYROD	14.88	6.11	8,207	583	408	108	12	6	2	6
NEWTON	3.60	0.66	2,472	79	83	23	1	6	2	2
GLOSSOP	15.66	3.98	7,556	535	389	148	17	10	7	3
ASHWOOD DALE	16.60	4.16	7,466	1,110	536	234	14	18	8	16
WATERSWALLOWS	7.77	3.54	1,253	127	80	47	1	2	0	5
GOWHOLE	18.56	3.03	9,661	844	590	179	13	12	6	14
HATTERSLEY	10.24	2.04	6,641	334	152	48	2	2	7	4
FERODO	12.12	0.00	3,698	370	245	88	5	4	2	5
DUKINFIELD	11.27	3.71	3,723	210	113	28	13	14	1	5
HADFIELD	11.62	2.53	6,795	646	298	75	16	12	5	3
HURST	11.36	4.31	8,621	411	165	33	4	3	4	2
MOSSLEY	13.29	3.41	8,963	502	356	90	13	7	5	7
GREENFIELD	9.16	3.01	5,427	570	299	103	4	11	2	7
ASHTON UNDER LYNE	26.08	10.06	10,401	887	1,080	242	26	35	16	18

4.3.2.2 Aggregated half-hourly load profile for each PC

As each PC represents a population of customers with similar load behaviours, an average load profile can be used to describe the demand variation for each PC customer. In this project, the average load profiles have been obtained using the energy consumption data from Electricity North West. For each PC, the data indicate the half-hourly energy consumption of total customers across the 365 days in 2013-2014. Therefore, the average daily load profile (in kW per customer) for each PC is derived as:

$$P_{average}(t) = \frac{E(t)}{T \times N_{PC}} \qquad \text{Eq. 4-1}$$

where t denotes the t^{th} half-hour period in a day, and t = 1, 2, …, 48. $E(t)$ denotes the total energy consumption during the t^{th} half-hour periods in a year, T is the time period of 365 × 0.5 hr. N_{PC} represents the total number of customers for the corresponding PC. Figure 4-7 shows the resulting daily load profile for each PC customer. In the computation, customers from PC5 to PC8 have been considered as a same group since their load curves are similar [12].

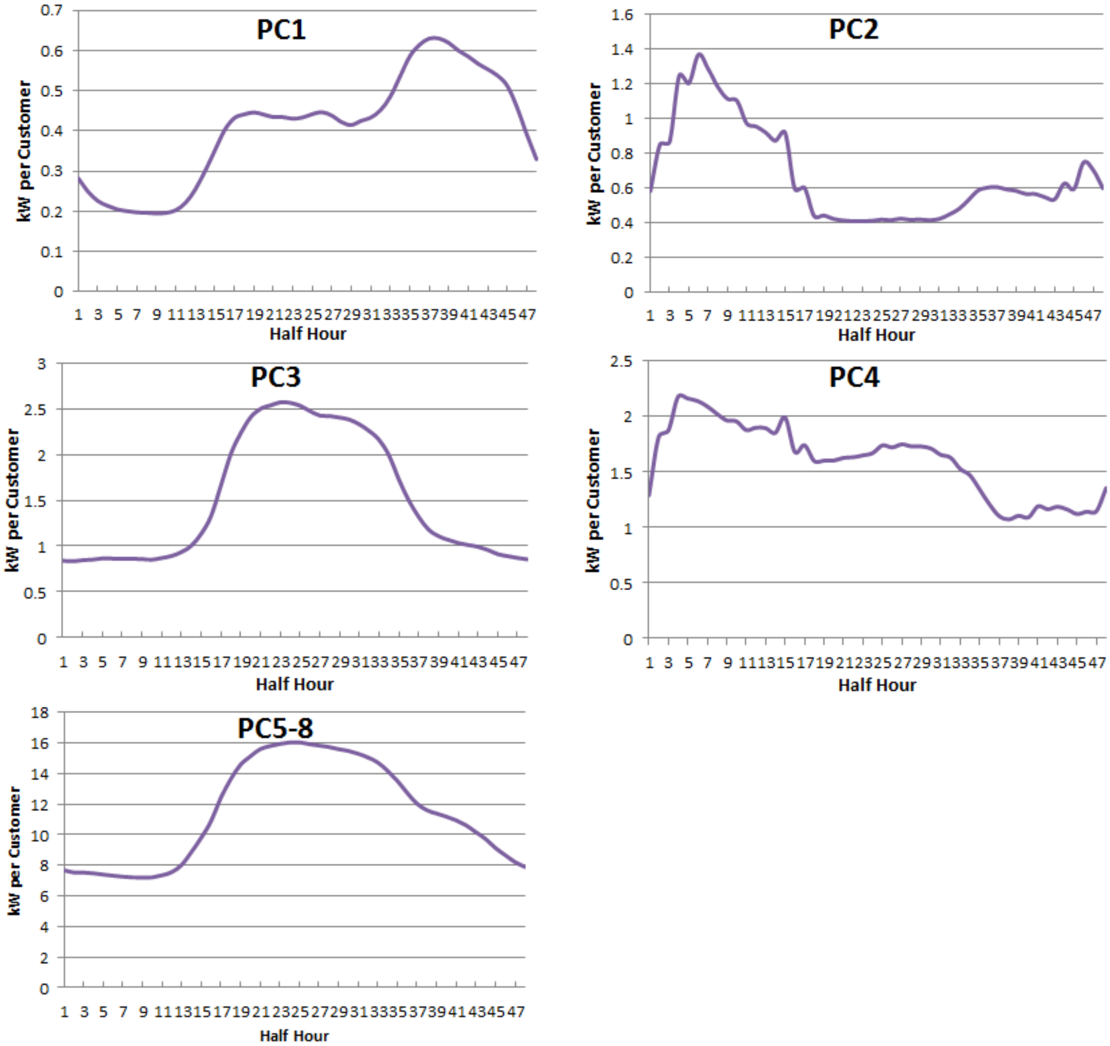


Figure 4-7: Average daily load profile for each PC customer (half-hourly resolution)

With the average daily load profile of each PC customer, the load profile of a primary substation can be estimated by multiplying the average load curve with the corresponding number of customers (as shown in Table 4-6). Figure 4-8 shows an example of the aggregated PC load profiles at the Denton East primary substations. According to the figure, the total substation load demand is predominated by the domestic PC1 loads. The aggregated PC load profiles can be used to estimate the demand variation of a substation with mixed customer types.

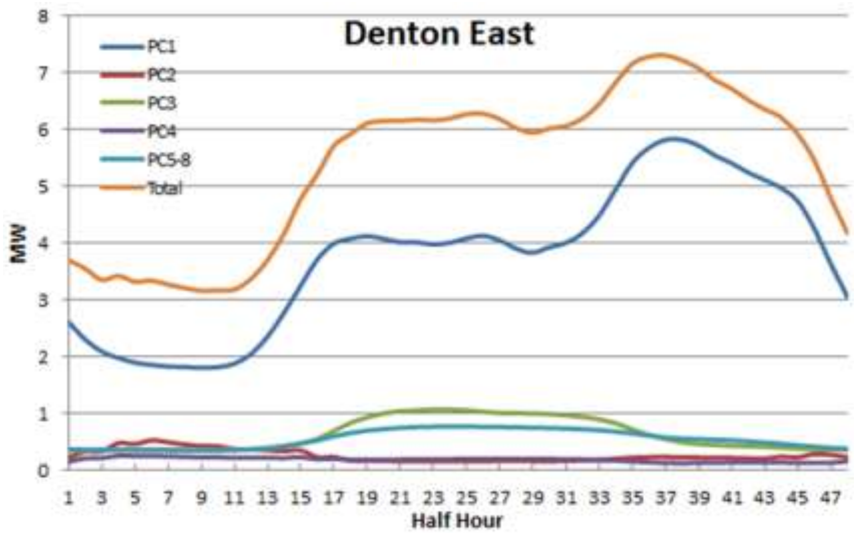


Figure 4-8: Aggregated daily load profile for each PC of the Denton East substation

4.3.2.3 Calculation of peak load share (PLS)

With the aggregated PC load profiles, the peak load can be identified for the substation, and the corresponding share of each PC demand at the peak time can be calculated. Considering the previous example of the Denton East substation, Table 4-7 shows the corresponding load share of each PC at the time of the substation with the maximum demand. The use of PLS values can help determine which PC has more contribution to the total substation demand. According to different customer types, the PLS values of a substation are divided into two parts: the domestic PLS (i.e. sum of PC1 and PC2) and the non-domestic PLS (i.e. sum of PC3 – PC8).

Table 4-7: Peak load share of each PC load demand at the Denton East substation

Primary substation	PLS (%)				
	PC1	PC2	PC3	PC4	PC5 - PC8
Denton East	79.64	3.19	7.51	1.75	7.91
	Domestic (PC1 & PC2)		Non-domestic (PC3 - PC8)		
	82.83		17.17		

4.3.2.4 Categorisation of primary substations

In a distribution network, each monitored substation can be considered as a unique substation type as it has accurate load profiles based on site measurements. An unmonitored substation will then belong to one monitored substation type, which has the closest domestic PLS value to the value of the unmonitored substation. The load profile of the unmonitored substation will then be obtained by multiplying its historical peak load value with the load shape (i.e. time-varying load percentage of peak load) of the corresponding monitored substation. Note that this substation categorisation method will also be used for the demand reduction capability studies in Section 5.

Table 4-8 shows the categorisation result for the primary substations in the Stalybridge network. The network has 7 CLASS-trial primary substations, which have demand monitoring data. Although the other 21 non-CLASS substations also have demand measurements, they have been considered as unmonitored substations in this case to validate the load profile estimation method.

Table 4-8: Categorisation of primary substations based on domestic PLS values

Monitored Primary Substations	Unmonitored Primary Substations					
Central Manchester (20.32%)*						
Hyde (75.97%)	Ardwick (55.82%)	Bradford (59.99%)	Ashton (65.53%)	Eastlands (74.28%)	Ashwood (74.51%)	Water Swallows (75.24%)
Gowhole (79.39%)	Ferodo (78.66%)					
Openshaw (81.07%)	Glossop (81.92%)	Dukinfield (81.07%)				
Denton East (82.83%)	Tame Valley (84.20%)	Greenfield Pry (82.52%)	Hadfield (83.71%)	Queens PK (84.15%)		
Droylsden East (86.26%)	Denton West (86.08%)	Newton (85.72%)	Mossley (86.18%)	Snipe Pry (87.64%)	Heyrod Pry (85.06%)	
Stuart (89.46%)	Monsall Pry (100%)	Hattersley Pry (90.99%)	Hurst (93.26)			

*****. The domestic PLS value, which is the sum of PC1 PLS and PC2 PLS.

4.3.2.5 Validation of load profile estimation

As described in Section 4.3.1, the load data of all 28 primary substations in the Stalybridge network have been provided. Among the 28 substations, there are 7 substations selected for the CLASS technique trials. In this case, these 7 substations have been considered as monitored substations while the remaining 21 substations have been assumed as unmonitored substations. To validate the load profile estimation method, the estimated load profiles of the 21 substations have been compared with their real measurements. For instance, the Denton East substation is a monitored substation and has its load shape (i.e. load divided by the peak load) based on real measurements. According to Table 4-8, the Tame Valley, Greenfield, Hadfield and Queens PK substations belong to the Denton East substation type, and hence their estimated load shapes are all represented by the load shape of Denton East. Figure 4-9 illustrates the comparison between the estimated load shape (based on Denton East) and the actual load shapes (obtained at the Tame Valley, Greenfield, Hadfield and Queens PK sites) during winter.

As shown in Figure 4-9, the estimated load shape is close to the actual load shapes. In addition, the load shapes have similar variations over the 24-hour period and have the same high or low demand periods. The validation results for other monitored substation types are presented in Appendix 5.

Considering the validation for all 4 seasons, Table 4-9 summarises the average estimation error for each seasonal load shape. From the table, the average estimation error over a year is 10.18%. The average error is not very small since only load profiles of 7 monitored substations have been used to estimate the profiles of 21 unmonitored substations. The load profile estimation can be improved by increasing the number of monitored substations.

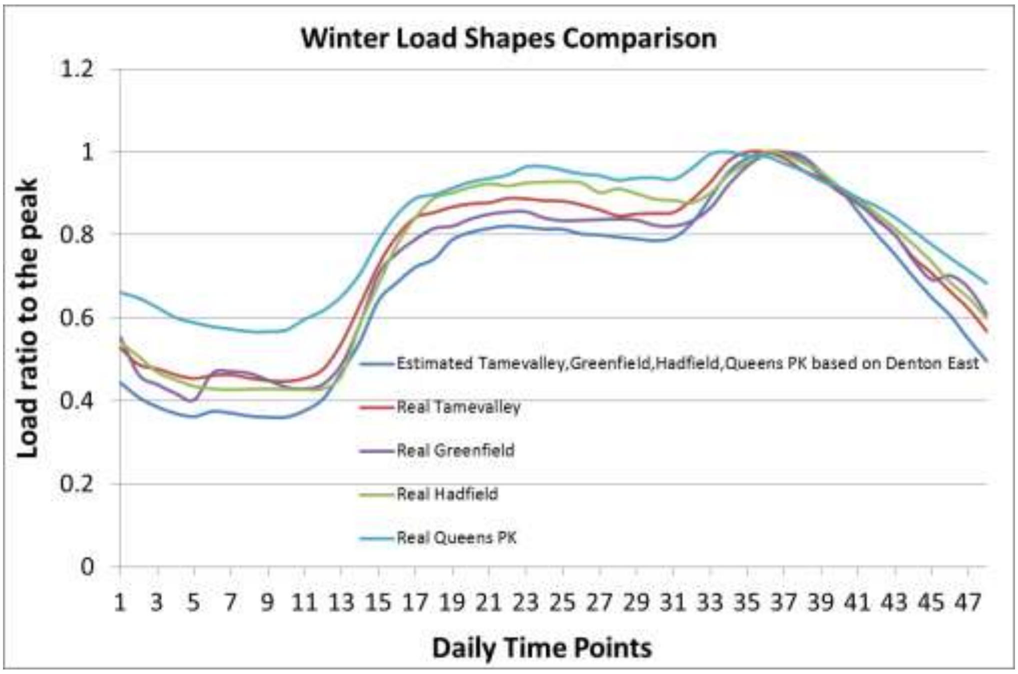


Figure 4-9: Comparison of estimated and actual load shapes for the Denton East group

Table 4-9: Average errors of load shape estimation in 4 seasons

Average error of the 21-substation load shape estimation					
Season	Spring	Summer	Autumn	Winter	Average
Average error	9.69%	8.34%	10.64%	12.05%	10.18%

4.4 Reactive power absorption capability studies with 24-hour load profiles

4.4.1 Introduction

This section presents the time-series network capability studies to investigate the impacts of changing load demands on the network reactive power absorption through the use of tap stagger. The studies first concentrate on assessing the VAr absorption capability of the Stalybridge network. As described in Section 4.3.1, each primary substation in the Stalybridge network has established daily load profiles for four seasons based on site measurements. Therefore, time-series load flow studies are carried out to quantify the 24-hour (48 × ½ hour) network VAr absorption capabilities in four seasons. The results are used to estimate the reactive power absorption capabilities of the Electricity North West EHV network and the GB primary distribution network. Since the tap staggering technique will not affect the secondary voltages of the primary substation transformers, the loads connected at the secondary sides will not change. Therefore, constant power load models are used throughout the studies. The results are described and analysed as follows.

4.4.2 Study results and analyses

4.4.2.1 VAr absorption capability of the Stalybridge network

As aforementioned, the Stalybridge network has load profiles established using site measurements for all its 28 primary substations. With the developed load profiles, network capability studies were started by setting all primary substations with Stagger =1 (i.e. one tap up for one transformer and one tap down for the other) throughout the simulation period. The studies were then repeated for Stagger = 2, 3, 4 and 5. Note that, during the simulations, the settings of Stagger = 1, 2, 3, 4 or 5 did not imply that all primary substations would be operated with the given staggered taps. The simulations have considered the physical limits of the transformer tap positions. Depending on the original tap positions before the staggering, some substations may not have enough headroom to implement the instructed tap stagger. For that case, the maximum achievable staggered taps would be used. According to the simulation results, all primary substations can achieve up to Stagger = 3. However, several substations cannot achieve Stagger = 4 or 5, due to their tap position limits.

Figure 4-10 and Figure 4-11 show the resulting 24-hour *Q* absorption capabilities and *P* losses (due to tap stagger) in four seasons, respectively.

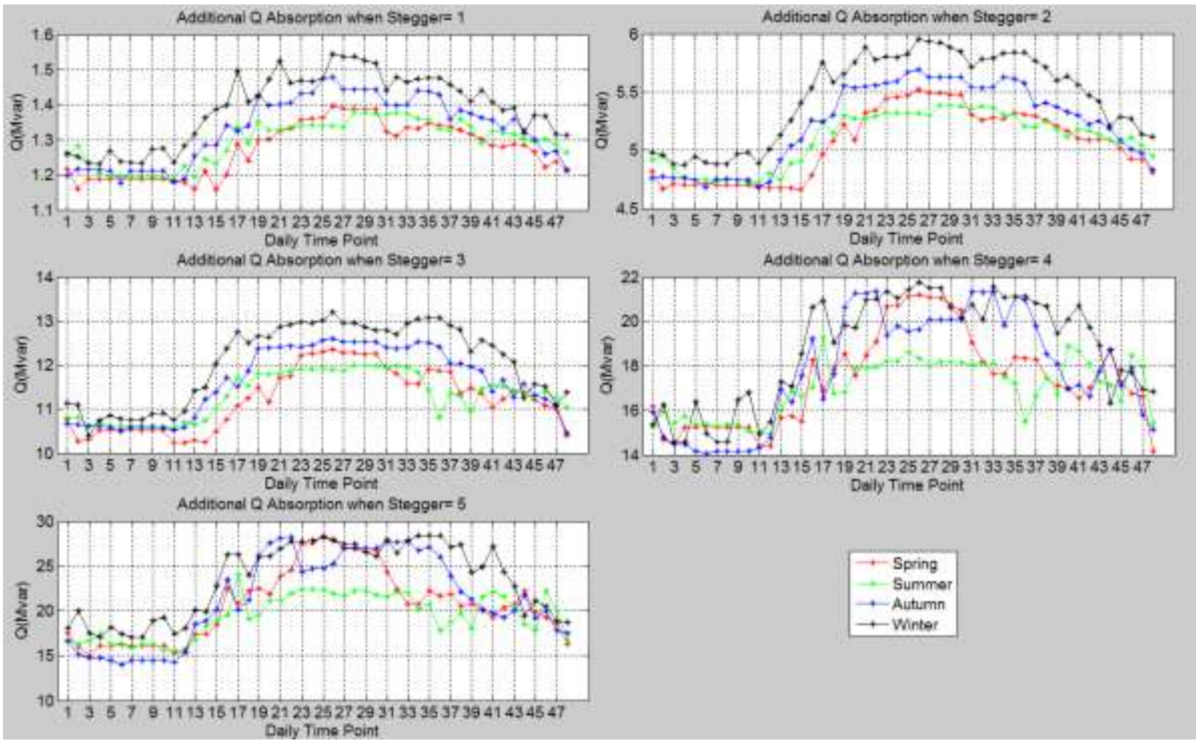


Figure 4-10: Stalybridge network *Q* absorption capabilities in 4 seasons

As shown in Figure 4-10, comparing different seasons, winter generally has the largest *Q* absorption capability. Since winter has higher network demands than other seasons, the currents through the 132kV and 33kV networks are higher. The additional reactive power consumptions of the transmission lines (caused by the downstream tap staggering) will be larger. Therefore, more reactive power absorption will be observed at the GSP in winter. In addition, since the tap positions of primary substation transformers are closer to the middle positions in winter, the transformers will have more headroom for tap stagger in winter. Consequently, the network has a higher reactive power absorption capability in winter than other seasons.

During a day, the *Q* absorption capability is high in the period from 12:00 to 18:00, while the capability is low in the period of 0:00 to 6:00. According to Figure 4-11, the network *P* loss introduced by tap stagger is about 17 to 20 times smaller than the *Q* absorption capability created. In addition, Appendix 6 demonstrates the capability results by comparing the network *Q* absorption capabilities (or *P* losses) with different staggered taps in a same season.

Note that the network demand level has impacts on the network reactive power absorption. In general, the network has higher reactive power absorption capability when the demand is high. This is because the additional VAr absorption of the lines (between the 132kV and 33kV networks) due to the tap stagger, has increased during the periods of high demand.

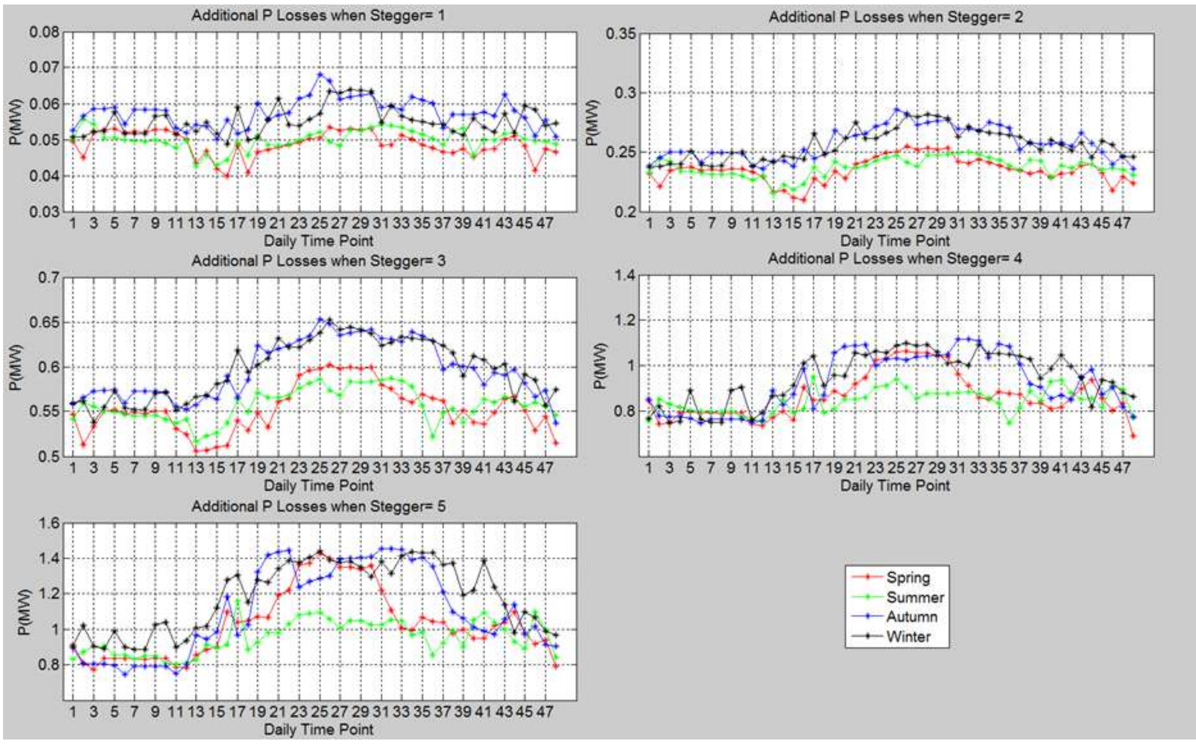


Figure 4-11: Stalybridge network *P* losses caused by tap stagger in 4 seasons

4.4.2.2 VAr absorption capability of the Electricity North West EHV network

The Electricity North West EHV network has a total of 354 primary substations with parallel transformers. As the EHV system has been designed as a radial network, the power flows of primary substations are almost independent of each other. Therefore, it has been assumed that the network *Q* absorption capability (or *P* loss) will increase linearly with the number of primary substations with tap stagger. The capability of the Electricity North West EHV network has been estimated by multiplying the results of the Stalybridge network with a scaling factor of 12.6 (i.e. = 354 / 28). Figure 4-12 and Figure 4-13 illustrate the 24-hour *Q* absorption capabilities and *P* losses for the Electricity North West network in 4 seasons, respectively.

As shown in the figures, the *Q* absorption capability and the *P* loss introduced by tap stagger have changed continuously over the 24-hour period. In addition, the *Q* absorption capability and *P* loss increase with the number of staggered taps.

Based on the results, Table 4-10 indicates the minimum and maximum *Q* absorption capabilities during a day for 4 seasons. Comparing the 4 seasons, winter generally provides the largest *Q* absorption capability due to its highest load demand.

Table 4-11 summaries the minimum and maximum network losses caused by the tap stagger in four seasons. Table 4-12 also indicates the total power losses for the Electricity North West network when tap stagger is applied or not.

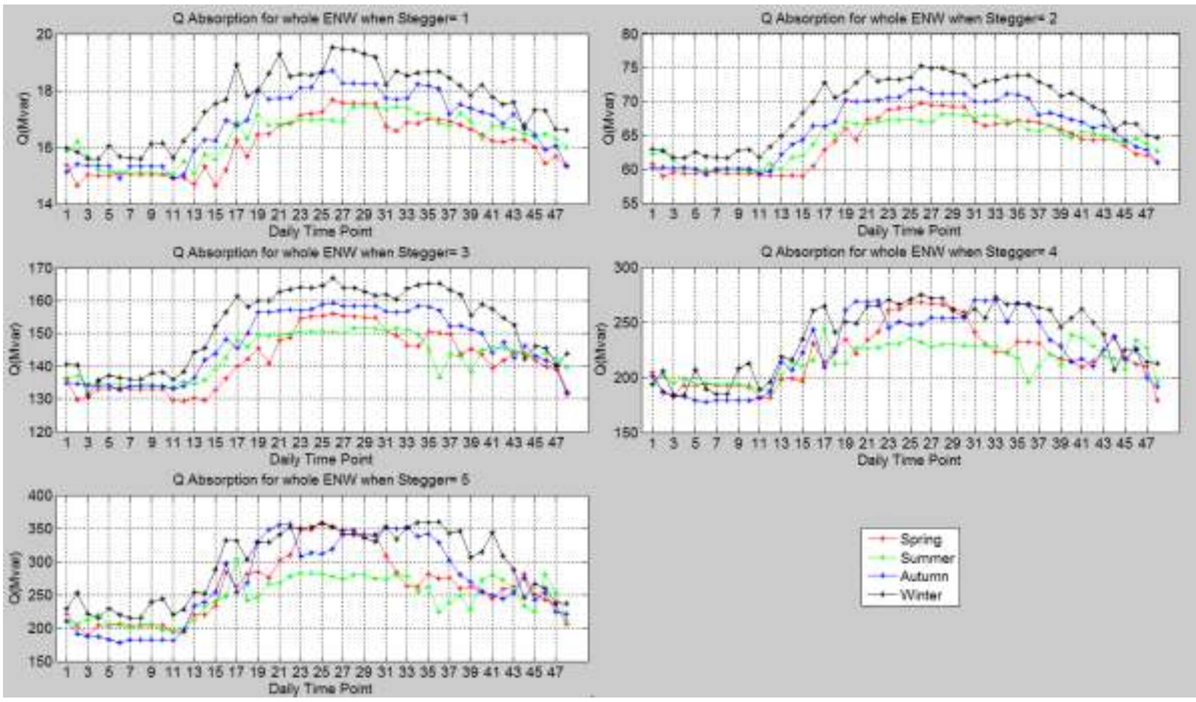


Figure 4-12: *Q* absorption capability for the Electricity North West EHV network

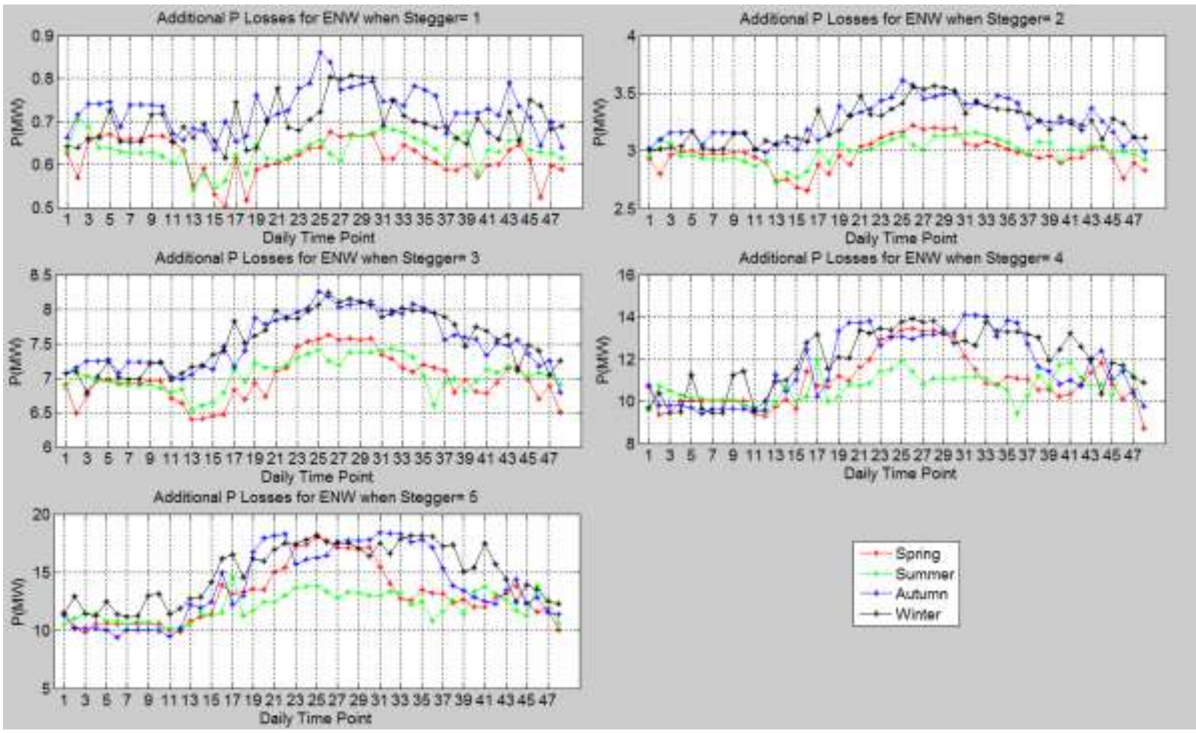


Figure 4-13: *P* loss caused by tap stagger for the Electricity North West EHV network

According to Table 4-11 and Table 4-12, the ratio of the *P* loss (caused by tap stagger only) to the total network losses can be calculated. For instance, the average loss ratio for Stagger = 1 in 4 seasons is 1.672%. From the results, the loss ratio increases with the number of staggered taps, e.g. up to 22% at Stagger = 5.

Table 4-10: Reactive absorption capability of the Electricity North West EHV network

Max No. of staggered taps	Stagger = 1		Stagger = 2		Stagger = 3		Stagger = 4		Stagger = 5	
Q capability (MVAr)	Min	Max	Min	Max	Min	Max	Min	Max	Min	Max
Spring	14.63	17.66	58.93	69.8	129.44	156.12	178.98	267.89	189.42	358.27
Summer	15.04	17.43	59.71	68.12	133.76	151.77	188.61	244.26	196.48	303.72
Autumn	14.89	18.7	59.21	71.91	132.13	159.33	177.48	270.09	177.48	356.22
Winter	15.57	19.53	61.62	75.3	131.2	166.99	184.1	275.14	215.43	359.41

Table 4-11: Network *P* loss caused by stagger only for the Electricity North West EHV network

Max No. of staggered taps	Stagger = 1		Stagger = 2		Stagger = 3		Stagger = 4		Stagger = 5	
P loss (MW)	Min	Max	Min	Max	Min	Max	Min	Max	Min	Max
Spring	0.504	0.675	2.656	3.218	6.397	7.619	8.732	13.438	9.803	18.015
Summer	0.539	0.705	2.72	3.16	6.535	7.426	9.433	12.03	10.156	14.691
Autumn	0.634	0.86	2.984	3.616	6.795	8.256	9.436	14.104	9.436	18.394
Winter	0.616	0.807	3.002	3.561	6.797	8.246	9.458	13.904	11.195	18.183

Table 4-12: Total power losses of the Electricity North West EHV network

Max No. of staggered taps	Stagger=0 (normal)		Stagger=1		Stagger=2		Stagger=3		Stagger=4		Stagger=5	
Total *P* loss (MW)	Min	Max	Min	Max	Min	Max	Min	Max	Min	Max	Min	Max
Spring	13.57	42.31	14.447	43.304	17.057	46.334	21.393	51.388	24.372	57.829	24.818	63.133
Summer	10.715	36.199	11.535	37.183	14.1	40.127	18.401	45.019	21.739	50.122	22.195	52.473
Autumn	12.158	43.538	13.054	44.603	15.686	47.705	20.043	52.833	22.705	59.408	23.147	63.878
Winter	17.238	60.721	18.172	61.793	20.91	65.02	25.34	70.388	28.238	76.524	30.127	82.075

4.4.2.3 VAr absorption capability of the GB primary distribution network

The CLASS project has tested the flexible tap changing techniques (e.g. voltage reduction or tap stagger) on 60 Electricity North West primary substations, which represent 17% of the Electricity North West primary substation assets and 1.5% of the GB primary distribution network [13]. In addition, the university has reviewed that the Electricity North West network represents 7.4% of the GB distribution system peak demand. This indicates that the capability study results of the Electricity North West network could be scaled up to the GB level via a scaling factor of about 13.5. However, for reactive power absorption, the scaling factor should be slightly lower due to the necessity of two transformers at each primary substation. Therefore, the project has used a scaling factor of 11 to conservatively estimate the *Q* absorption capability of the GB primary distribution system.

Table 4-13 and Table 4-14 summarise the *Q* absorption capability and the corresponding *P* loss caused by the tap stagger for the GB system. Table 4-15 also indicates the total power losses for the GB system when tap stagger is applied or not.

Table 4-13: Reactive absorption capability of the GB primary distribution network

Max No. of staggered taps	Stagger = 1		Stagger = 2		Stagger = 3		Stagger = 4		Stagger = 5	
Q capability[a] (MVAr)	Min	Max	Min	Max	Min	Max	Min	Max	Min	Max
Spring	160.9	194.3	648.23	767.8	1423.8	1717.3	1968.8	2946.8	2083.6	3941
Summer	165.4	191.7	656.81	749.3	1471.4	1669.5	2074.7	2686.9	2161.3	3340.9
Autumn	163.8	205.7	651.31	791	1453.4	1752.6	1952.3	2971	1952.3	3918.4
Winter	171.3	214.83	677.82	828	1443.2	1836.9	2025.1	3026.5	2369.7	3953.5

a. Based on the Electricity North West capability multiplying a scaling factor of 11 [13].

Table 4-14: Network *P* loss caused by stagger only for the GB primary distribution network

Max No. of staggered taps	Stagger = 1		Stagger = 2		Stagger = 3		Stagger = 4		Stagger = 5	
P loss (MW)	Min	Max	Min	Max	Min	Max	Min	Max	Min	Max
Spring	5.54	7.43	29.22	35.4	70.37	83.81	96.05	147.82	107.83	198.17
Summer	5.93	7.76	29.92	34.76	71.89	81.69	103.76	132.33	111.72	161.6
Autumn	6.97	9.46	32.82	39.78	74.75	90.82	103.8	155.14	103.8	202.33
Winter	6.78	8.88	33.02	39.17	74.77	90.71	104.04	152.94	123.15	200.01

Table 4-15: Total power losses of the GB primary distribution network

Max No. of staggered taps	Stagger=0 (normal)		Stagger=1		Stagger=2		Stagger=3		Stagger=4		Stagger=5	
Total *P* loss (MW)	Min	Max	Min	Max	Min	Max	Min	Max	Min	Max	Min	Max
Spring	149	465	159	476	188	510	235	565	268	636	273	694
Summer	118	398	127	409	155	441	202	495	239	551	244	577
Autumn	134	479	144	491	173	525	220	581	250	653	255	703
Winter	190	668	200	680	230	715	279	774	311	841	331	903

4.5 Validation of tap stagger

4.5.1 Introduction

In the Electricity North West distribution network, 60 primary substations have been selected to carry out site trials for the CLASS techniques. There are 7 primary substations from the Stalybridge network. This section aims to validate the tap staggering technique by comparing the trial results with the simulation results. First, to validate the VAr absorption at the transformer side, a single primary substation named 'Dickinson St' is selected to carry out the staggering trial and the result is compared with the OpenDSS simulation result. Secondary, to validate the VAr absorption at the GSP side, all 7 CLASS primary substations in the Stalybridge network are instructed to carry out tap staggering simultaneously. The trial results obtained from Nation Grid (NG) are compared with the load flow study results. The details are described as follows.

4.5.2 Validation of tap stagger at a single primary substation

As the Dickinson St primary substation is close to the upstream BSP (132/33 kV), it has been selected to test the reactive power absorption of two parallel transformer with staggered taps. Figure 4-14 illustrates the schematic of the site trial.

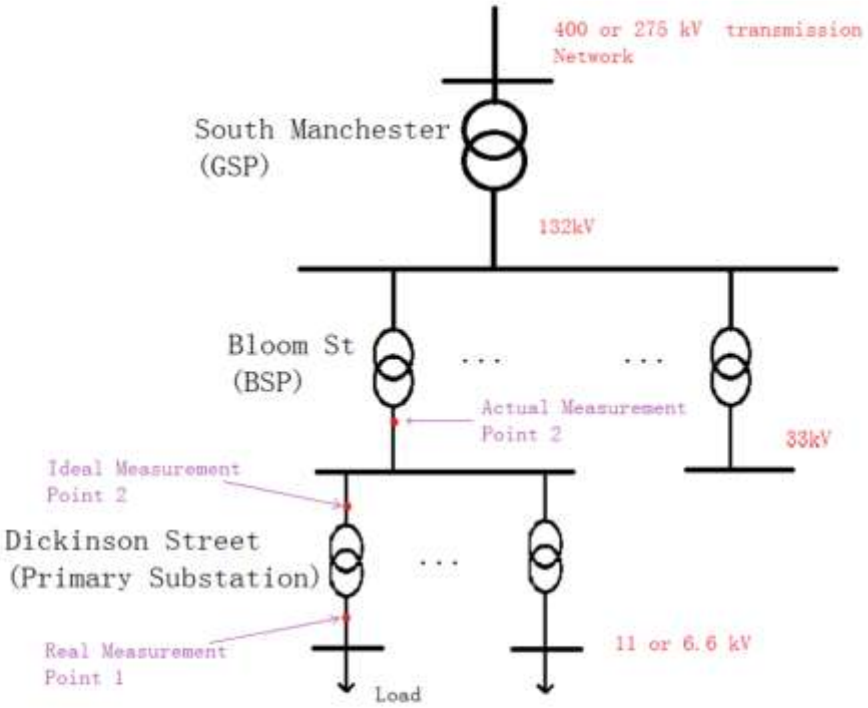


Figure 4-14: Schematic of the tap staggering trial at the Dickinson St substation

In theory, the reactive power data from both the primary and secondary sides of the two parallel transformers are required to calculate the additional VAr absorption caused by tap stagger. However, in practice, only transformer secondary sides usually have monitoring equipment installed. Therefore, during the trial, the reactive power demands of the upstream BSP transformers have been measured as shown in Figure 4-14. Since the Dickinson St substation is close to its upstream BSP, the reactive power variation observed at the BSP will be equal to the transformer VAr absorption caused by tap stagger. Note that the reactive power measurements taken at the primary substation secondary sides have been used to monitor the load changes during the testing period.

In the trial, the number of staggered taps increased successively from 0 up to 3 taps (i.e. 3 taps up for one transformer and 3 taps down for the other). The total testing period is around 10 min, and each tap staggering stage has 3 to 4 min. Table 4-16 shows the reactive power measurements of the BSP transformers at each tap staggering stage. Figure 4-15 also illustrates the downstream reactive power outputs measured at the secondary sides of the Dickinson St primary substations.

Table 4-16: Total reactive power demands measured at the Bloom St BSP transformers

Stage:	**Initial (normal)**	**Stagger = 1**	**Stagger = 2**	**Stagger = 3**
Total reactive power demands of BSP transformers (MVAr)	11.8	11.8	12.0	12.2

Figure 4-15: Reactive power outputs measured at the secondary sides of the Dickinson St substation

The primary substation VAr absorption capability has been obtained by calculating the BSP reactive power demand variation (compared to the initial state). Table 4-17 indicates the test results as well as the OpenDSS simulation results.

Table 4-17: Transformer *Q* absorption caused by tap stagger from trial and simulation results

ΔQ (MVAr)	Stagger=1	Stagger=2	Stagger=3
Trial Result	0	0.2	0.4
Simulation Result	0.0445	0.1780	0.4011

The main findings are summarised below:

- For Stagger = 1, no extra *Q* absorption has been observed in trial, since the expected value of 0.0445 MVAr (from the load flow study) is less than the accuracy of the measurement (i.e. 0.1 MVAr).
- For Stagger = 2, the simulation result of 0.178 MVAr can be rounded to 0.2 MVAr as the accuracy of the measuring equipment is 0.1 MVAr.
- For Stagger = 3, the error between the trial and simulation results is only 0.275%.

4.5.3 **Validation of tap stagger for the Stalybridge network**

This section presents the validation of reactive power absorption observed at GSP sides. The 7 CLASS primary substations in the Stalybridge network have been instructed to carry out the tap staggering simultaneously. The corresponding reactive power demand data of the Stalybridge GSP have been obtained from NG and the measurements have been compared with the OpenDSS load flow results.

4.5.3.1 National Grid data analysis

In the trial, the 7 CLASS substations in the Stalybridge network have simultaneously carried out the tap staggering operation from Stagger = 1 to 3, and each tap staggering stage has last for a half hour. Between each stage, there was a half-hour 'settling' period, during which all transformers returned to their normal tap positions. This provides the monitoring of primary substation load changes during the trial. The corresponding reactive power flow variations at the Stalybridge GSP have been obtained from NG. However, the measurements do not show significant reactive power changes when the tap stagger was applied. The main reasons include:

1) As the 7 CLASS substations did not actually start the tap staggering at the same time, there was a transient period between each staggering stage. The transient period started from the first staggering substation and ended on the last staggering substation. In this trial, the shortest transient period is about 3 minutes while the longest one is about 18 minutes. During these transient periods, the primary substation *Q* demands have already changed. The *Q* demand variations have counteracted the *Q* absorption created by the tap stagger. Therefore, the total reactive power changes observed at the upstream GSP are not significant.
2) According to the reactive power data provided by NG, the measurements of the four 275/132 kV super grid transformers (SGTs) were not taken at the same time. The time difference varies from seconds to minutes. In addition, the sampling rates for the four SGTs were different. Therefore, it is difficult to sum the measurements from all SGTs to calculate the total reactive power flow observed at the GSP for a certain moment.
3) The high resolution (e.g. one sampling per minute) load data of the 21 non-CLASS substations are not available for the testing period. Therefore, it is difficult to offset the distribution network *Q* demand changes.

4.5.3.2 Methodology for NG data processing and validation

To mitigate the impacts of distribution network demand variations on the total reactive power observed at the GSP, a method has been developed to process the NG data. Figure 4-16 illustrates an example of the expected *Q* variation curve observed at the GSP during the trial. The slopes in the curve represent the transient periods, and the straight lines represent the steady-state periods. As shown in the figure, the NG samples close to the ends of an increasing/decreasing edge can be used to calculate the network VAr absorption introduced by tap stagger. The sampling window for the NG data (represented by red circles in Figure 4-16) has been set to 5 minutes to reduce the load variation impacts while still having enough measurements.

According to Figure 4-16, at each tap staggering stage, the method can provide two *Q* absorption results based on the increasing and decreasing edges, respectively. The average value has been used to validate the simulation result.

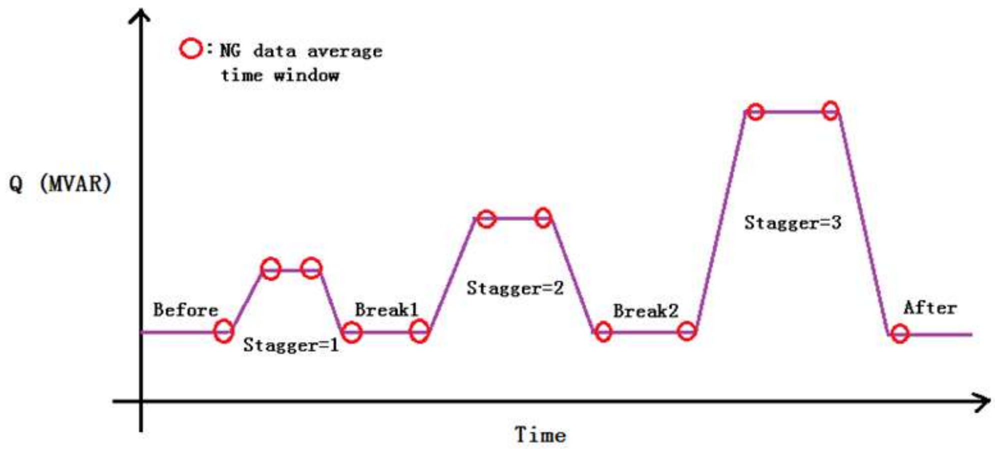


Figure 4-16: Expected *Q* variation curve observed at the GSP during the stagger trial

Figure 4-17 illustrates the corresponding tap stagger studies carried out in OpenDSS. For the 7 CLASS substations, the load data during the testing period have been downloaded from the IHOST system and used in the network model, so that the simulated loads of the 7 CLASS sites keep consistent with the trial.

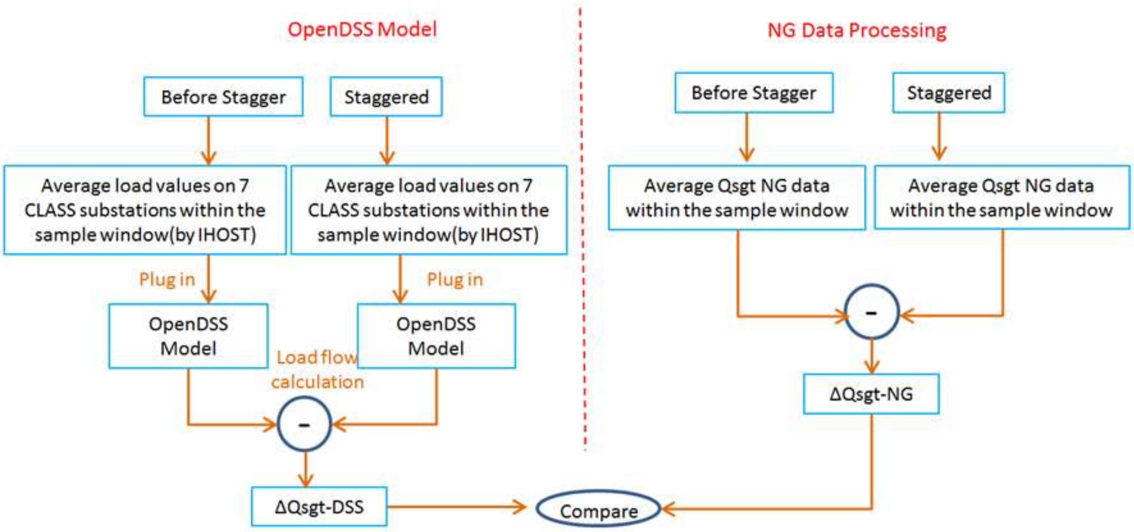


Figure 4-17: Tap stagger validation process for the Stalybridge network

4.5.3.3 Validation result and analysis

With the data processing method described above, the tap staggering validation for the Stalybridge GSP has been carried out. Figure 4-18 shows the average *Q* absorption (at the GSP) obtained from the NG and the corresponding simulation result from the network model.

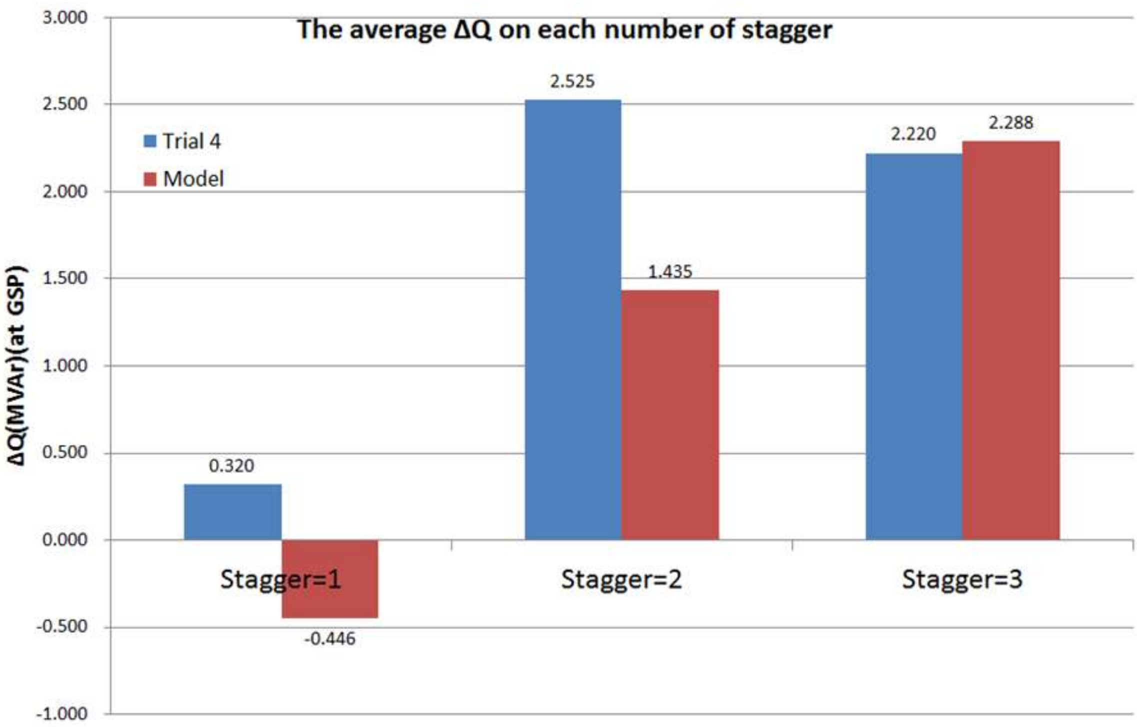


Figure 4-18: Site trial and simulation results for the Stalybridge GSP validation

As shown in Figure 4-18, the trial and simulation results for Stagger = 3 match very well, with a small error of 3.06%. However, for Stagger = 1 and 2, since the *Q* absorption created by the tap stagger is small, the reactive power variation at the GSP mainly depends on the downstream distribution network *Q* demand changes. Therefore, the comparison results for Stagger = 1 and 2 are not as good as Stagger = 3.

4.6 Summary

In this section, the network reactive power absorption capability has been investigated. With the developed two network models (South Manchester and Stalybridge), the network *Q* absorption capability studies have first been carried out with fixed load demands. Based on the linear approximation method, the *Q* absorption capability per primary substation has been estimated.

The seasonal 24-hour (48 × ½ hour) load profiles for all primary substations in the Stalybridge network have been developed based on site measurements. In addition, a load profile estimation method has been proposed for unmonitored substations. The method first categorises the primary substations based on PLS values and then uses the load shapes of monitored substations to represent the shapes of unmonitored substations.

With the developed load profiles of the Stalybridge network, the 24-hour (48 × ½ hour) network *Q* absorption capabilities have been assessed for 4 seasons. In addition, the *Q* absorption capability has been extended to the entire Electricity North West network and the GB primary distribution network.

Finally, the tap staggering technique has been validated considering a single primary substation trial and the Stalybridge GSP trial. For the GSP validation, a method has been developed to process the NG data in order to mitigate the impacts of load demand variations on the site trial results.

5 Demand Reduction Capability Studies

5.1 Introduction

One of the main objectives of the CLASS project is to investigate the distribution network capability to provide demand response through the voltage reduction of primary substations. The relationships between network demands and voltages depend on the types of customer loads. As the aforementioned tap stagger validation studies have proved the Stalybridge network model is correct, WP2-Part B has also assessed the demand reduction capability of the Stalybridge network. The results help support the analyses of network demand response by WP2-Part A.

This section investigates the demand reduction capability of the Stalybridge EHV network. The studies start by assessing the network *P* reduction capability with fixed load models, i.e. constant impedance model (CZ), constant current model (CI), constant power model (CP) and mixed model (50% CZ + 50% CP). As WP1 has established exponential load models based on site measurements, the Stalybridge network model is tested again using the developed load models. In order to apply the load models (from WP1) in OpenDSS, a method is developed to convert the exponential models to *ZIP* models (i.e. combinations of CZ, CI and CP load models). With the converted *ZIP* models, studies are carried out to quantify the 24-hour (48 × ½ hour) demand reduction capabilities in 4 seasons.

5.2 Demand reduction studies with fixed load models

5.2.1 Static load models

As the adjustments of transformer tap positions can change bus voltages, the connected load demands can change, depending on the relationships between voltages and demands. Different load types will have different voltage-demand relationships and result in different *P* reduction capabilities. Since the CZ, CI and CP load models are widely used in load flow studies [14], this section first presents the network demand reduction capability studies based on these load models. The load at each primary substation in the Stalybridge network model has been modelled as the following 4 types, respectively:

1) Constant power load,
2) Constant current magnitude load,
3) Constant impedance load,
4) Mixed load (50% of constant power load and 50% of constant impedance load).

5.2.2 Simulation results

5.2.2.1 Demand reduction capabilities

With the load models described above, load flow studies have been carried out to assess the aggregated demand reduction at the GSP by deliberately reducing the primary substation voltages. The studies have tested the network by decreasing all primary substation transformer tap positions up to 4 taps down.

Figure 5-1 illustrates the network demand reduction capabilities with the four different load models. According to the results, the *P* reduction increases with the number of taps down (i.e. reduced voltage). For the CP load model, the results indicate negative demand reduction. Since the CP load does not change its power consumption with voltage, the line current will increase to deliver the same amount of power if the voltage decreases. Consequently, the line losses will increase and lead to an increase in the observed demand at the GSP. In terms of the other load models, the CZ load model produces the largest demand reduction since its voltage has the most significant impact on the power consumption.

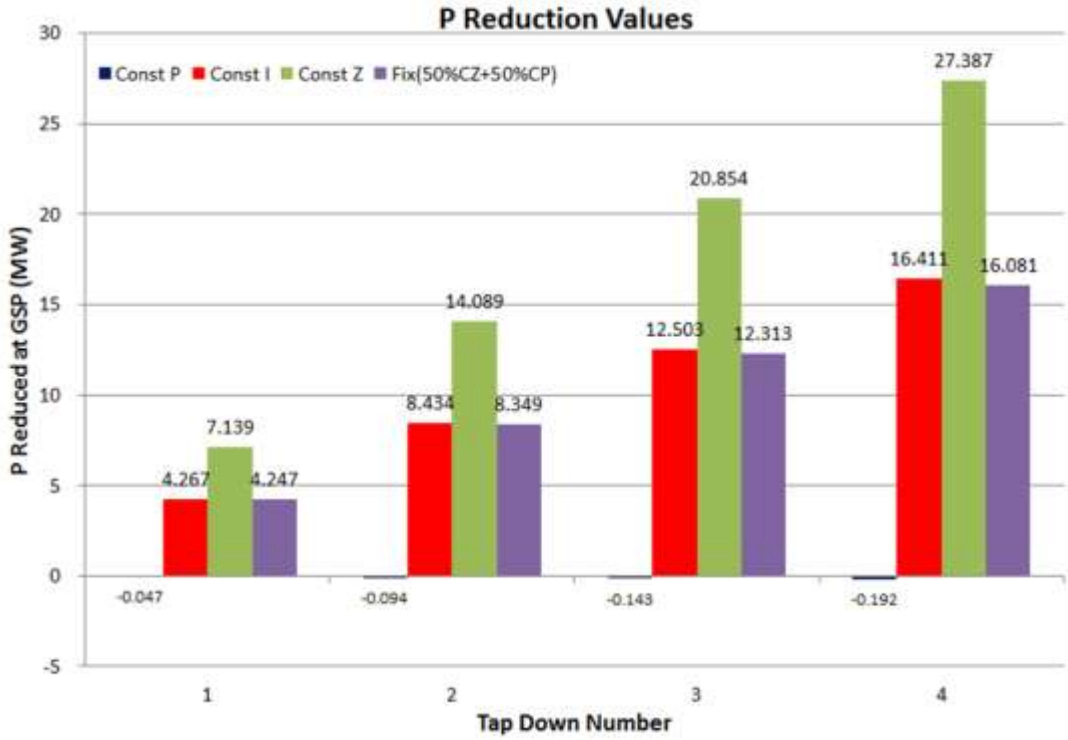


Figure 5-1: Demand reduction of the Stalybridge network with different load models

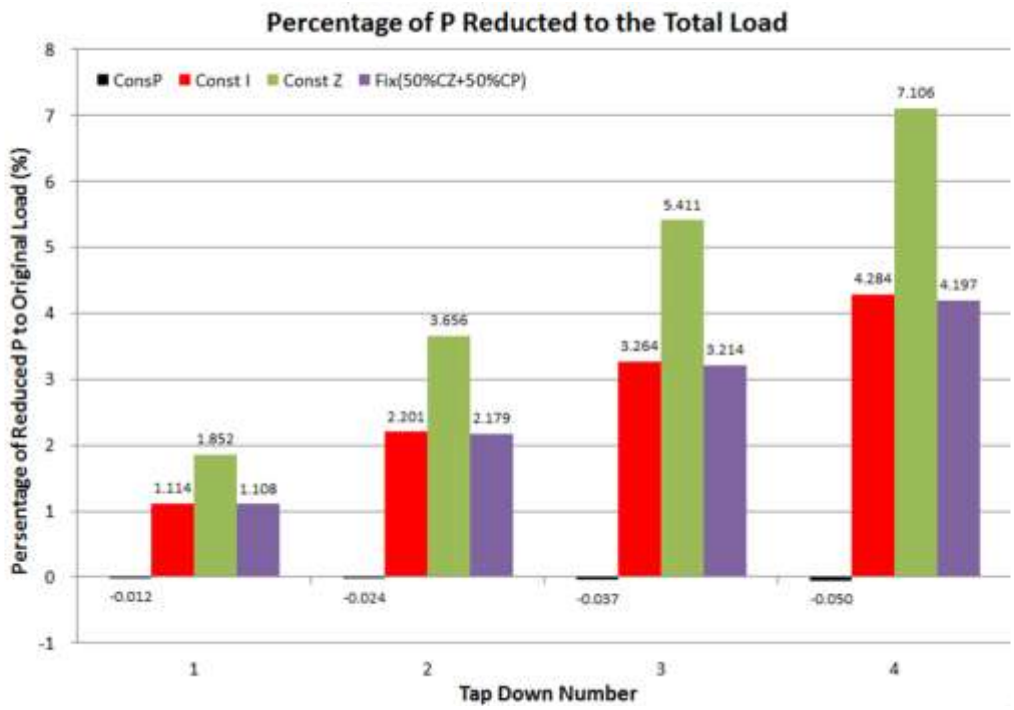


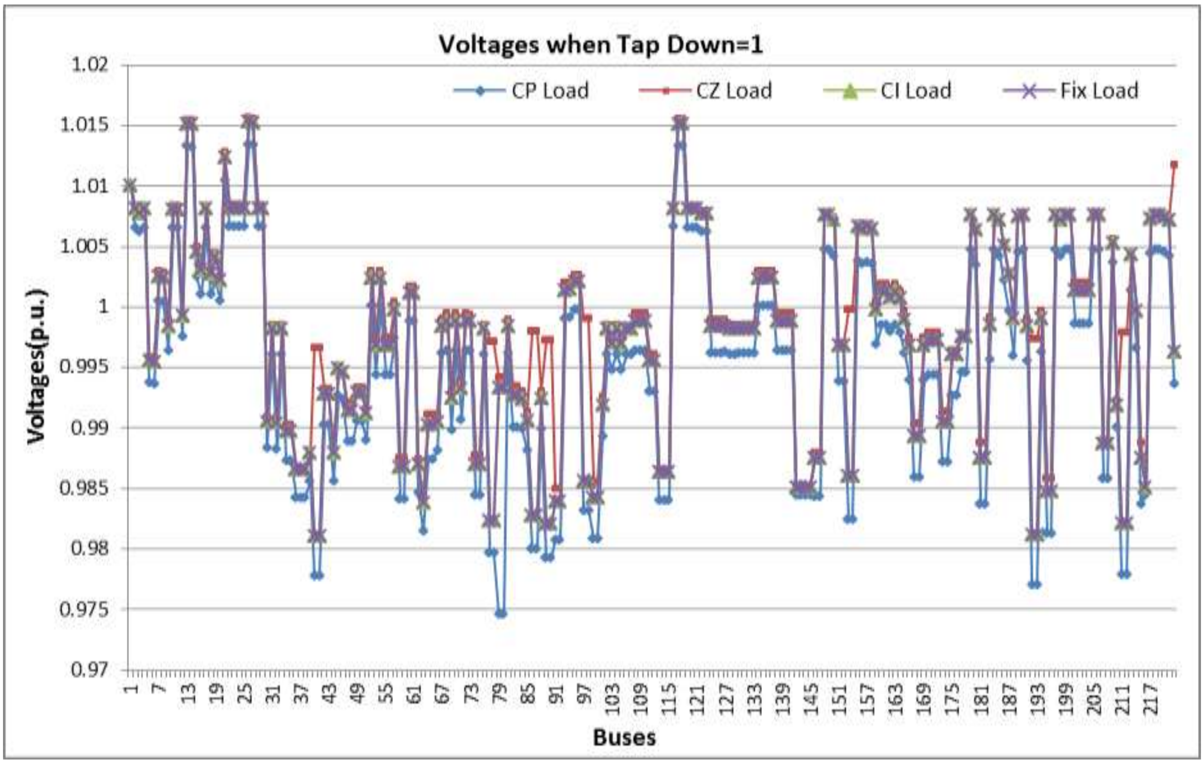
Figure 5-2: Demand reduction in percentage of the Stalybridge network demand

Figure 5-2 shows the demand reduction in percentage of the total network demand. For instance, if tap down = 2 (i.e. around 3% voltage reduction) and all loads on primary substations are CZ types, there will be about 3.7% active power reduction observed at the GSP.

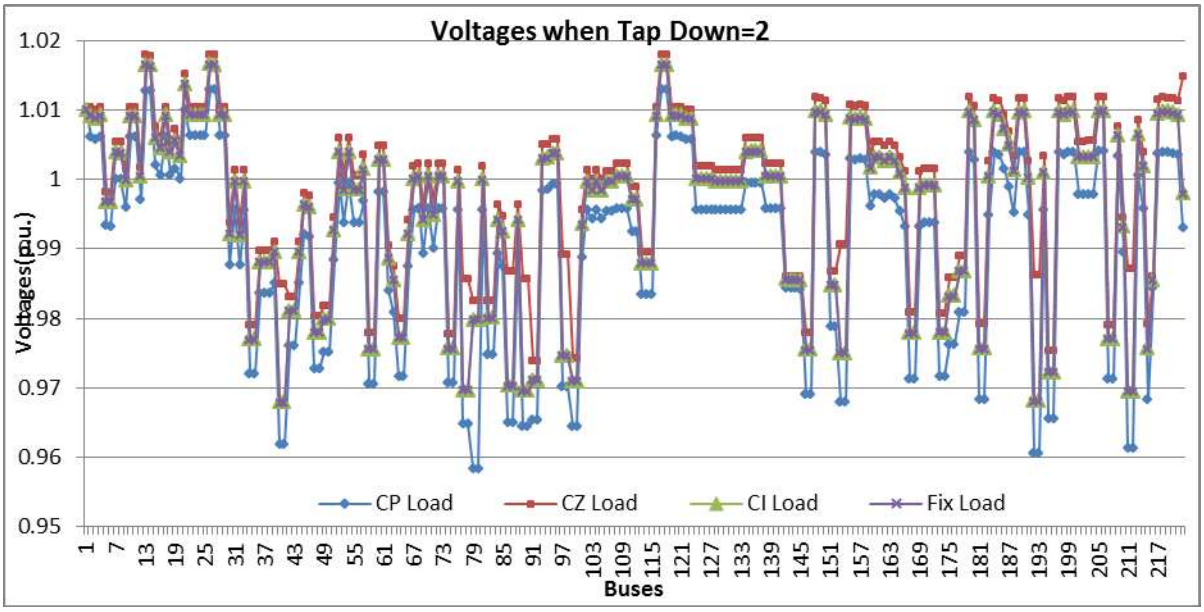
5.2.2.2 Bus voltages

To ensure that the bus voltages have still stayed within the statutory limits (i.e. 1.06 pu - 0.94 pu for primary substations) after the voltage reduction, all bus voltages in the Stalybridge network have been checked from tap down = 1 to 4. Figure 5-3 demonstrates the results.

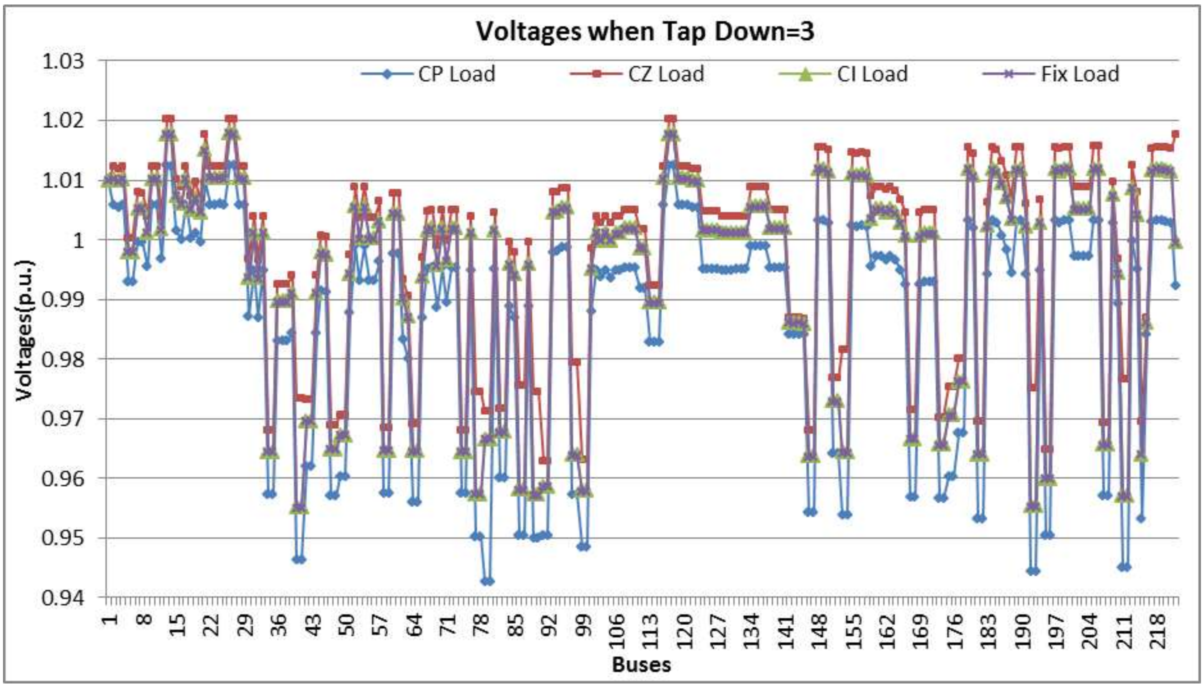
As can be seen from the figures, the CP load model results in the lowest bus voltages since it increases the line current with voltage reduction. Consequently, the line voltage drop increases. For tap down = 1 and 2, the bus voltages for all load models stay within the statutory limits. However, for tap down = 3, some bus voltages are just above the lower limit (0.94 pu). In addition, for tap down = 4, Figure 5-3(d) shows that several buses have already violated the voltage limit due to the large voltage reduction. Therefore, considering the statutory limits for 132-33kV network voltages, the voltage reduction of 1%-4% (i.e. 1 to 3 taps down) is suggested.



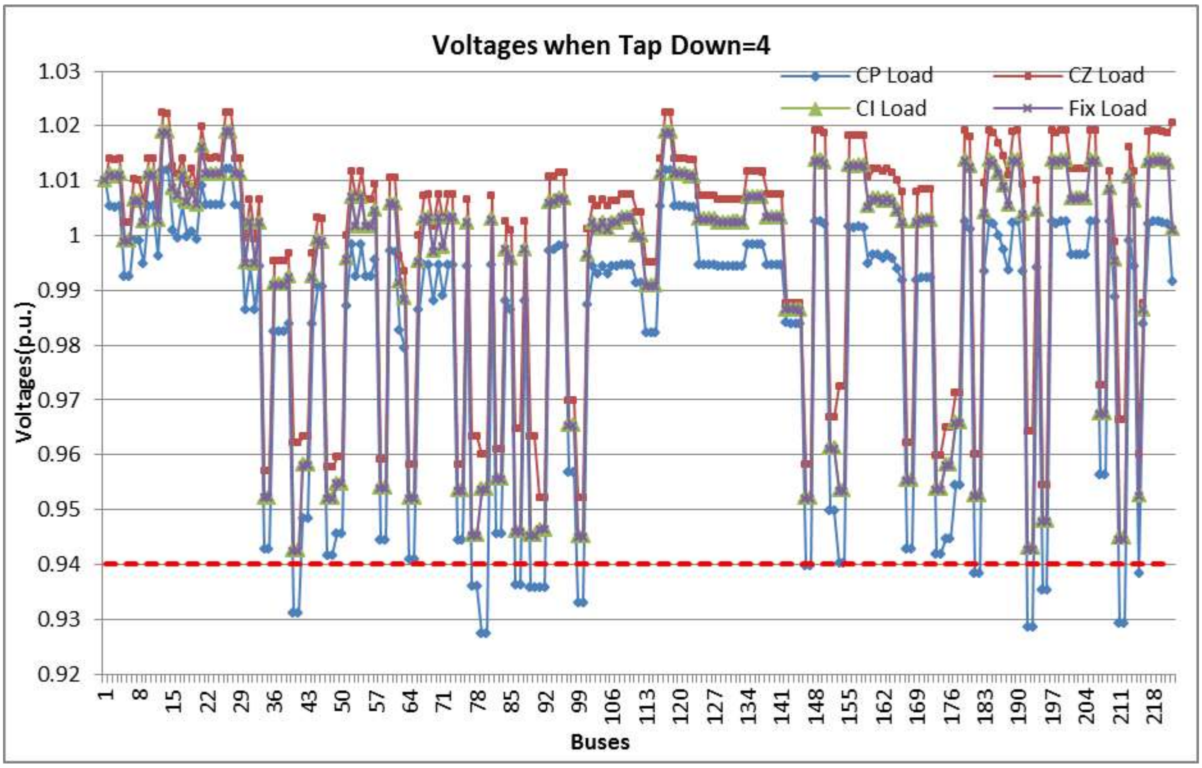
(a) All primary substation transformers with one tap down



(b) All primary substation transformers with two taps down



(c) All primary substation transformers with three taps down



(d) All primary substation transformers with four taps down

Figure 5-3: Bus voltages in the Stalybridge network with the voltage reduction technique

5.3 *ZIP* load model conversion

5.3.1 Introduction

To estimate the *P* reduction capability more accurately (e.g. 24-hour for 4 seasons), the load models from WP1 have been used. The load models have been developed based on site measurements and can reflect the real voltage-demand characteristics.

In the CLASS project, WP1 has provided the exponential load models for the selected 60 CLASS primary substations. The load models describe the voltage-demand relationships over the 24-hour (48 × ½ hour) period in a day and in four seasons. At each time point, the relationship is expressed as:

$$\frac{P}{P_0} = (\frac{V}{V_0})^{kp} \quad \text{Eq. 5-1}$$

$$\frac{Q}{Q_0} = (\frac{V}{V_0})^{kq} \quad \text{Eq. 5-2}$$

where,
P and P_0: actual and initial active power consumptions of the load,
Q and Q_0: actual and initial reactive power consumptions of the load,
V and V_0: actual and initial voltage magnitudes at the load bus,
kp: exponential coefficient describing the V-P relationship, obtained from WP1,
kq: exponential coefficient describing the V-Q relationship, obtained from WP1.

Since the OpenDSS software cannot handle exponential load models directly, the load models (from WP1) have been converted to *ZIP* models. The V-P relationship of a *ZIP* load model is described as:

$$\frac{P}{P_0} = p_1 x^2 + p_2 x + p_3 \qquad \text{Eq. 5-3}$$

$$x = \frac{V}{V_0} \qquad \text{Eq. 5-4}$$

where p_1, p_2 and p_3 are the coefficients of the constant impedance, constant current and constant power load models, respectively. Note that $p_1 + p_2 + p_3 = 1$. The V-Q relationship has the similar expression.

This section presents a method to convert the load models from exponential to *ZIP*. The conversion error is analysed. Among the 60 CLASS primary substations which have the exponential load models, 7 of them belong to the Stalybridge network. The load models for the other 21 non-CLASS substations in the Stalybridge network are estimated based on the method for estimating load profiles (see section 4.3.2).

5.3.2 Methodology for *ZIP* model conversion

Based on Eq. 5-1 and Eq. 5-3, the conversion process is to find the appropriate values for p_1, p_2 and p_3, in order to minimise the power consumption error between the exponential model and the *ZIP* model (i.e. $x^{kp} \approx p_1 x^2 + p_2 x + p_3$, where $x = \frac{V}{V_0}$).

According to Taylor Series, a real or complex-valued function *f*(*x*), which is infinitely differentiable at a real or complex number *a*, can be represented as an infinite sum of polynomials:

$$f(x) = f(a) + \frac{f'(a)}{1!}(x-a) + \frac{f''(a)}{2!}(x-a)^2 + \frac{f'''(a)}{3!}(x-a)^3 + \cdots \qquad \text{Eq. 5-5}$$

Since bus voltages are usually between the statutory limits, *x* varies within the range of 0.94 - 1.06. Therefore, the exponential function of x^{kp} has been expanded at $a = 1$ using Taylor Series. The coefficients of the first three polynomials have been used to determine p_1, p_2 and p_3. The results are given in Eq. 5-6:

$$x^{kp} \approx \frac{kp(kp-1)}{2}x^2 + kp(2-kp)x + \frac{(kp-1)(kp-2)}{2} \qquad \text{Eq. 5-6}$$

Based on Eq. 5-6, p_1, p_2 and p_3 can be derived as:

$$p_1 = \frac{kp(kp-1)}{2}$$

$$p_2 = kp(2-kp) \qquad \text{Eq. 5-7}$$

$$p_3 = \frac{(kp-1)(kp-2)}{2}$$

5.3.3 Conversion error analysis

According to Eq. 5-7, the exponential load models with various values of *kp* and *kq* can be converted into *ZIP* models. Figure 5-4 shows an example of the comparison between the exponential and *ZIP* model with *kp* = 1.5.

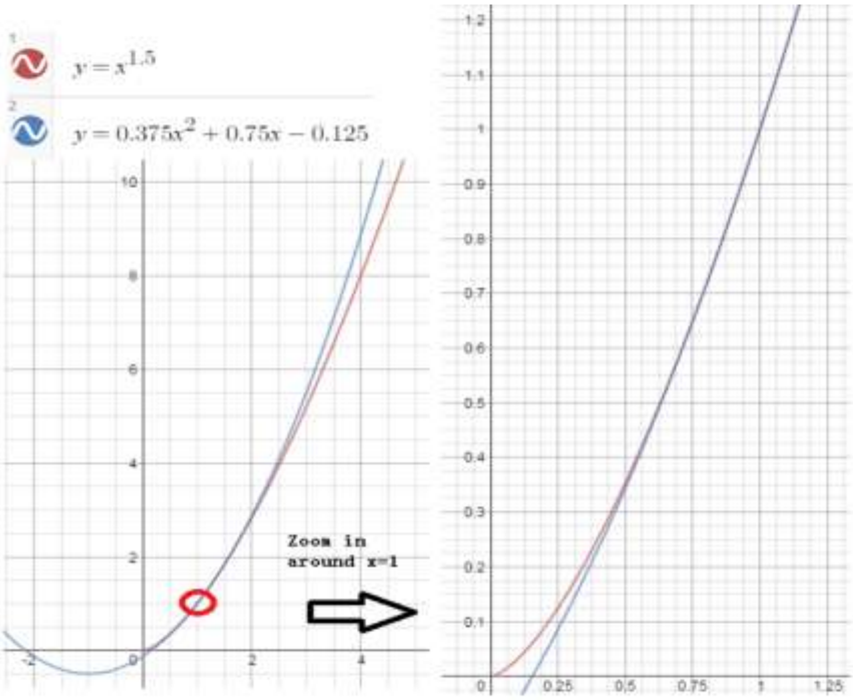


Figure 5-4: Comparison between the exponential and *ZIP* load models with *kp* = 1.5

From the figure, the converted model is most accurate at $x = 1$ with zero error. As x increases or decreases from 1, the error between the two models increases. Under the normal operating conditions, i.e. $0.94 \le x \le 1.06$, the power consumptions from the exponential model (red line) and the converted *ZIP* model (blue line) are almost the same, and the two lines overlap with each over.

Considering the normal operation, at $x = 0.94$ and 1.06, the converted *ZIP* model will have the largest errors to the given exponential model. By checking all errors between the converted *ZIP* models and the exponential models provided by WP1, the average conversion errors at x = 0.94 and 1.06 are only 0.0009% and 0.0007%, respectively. In addition, considering the case when the average conversion error is around 1%, it has been observed that the voltage has become 1.97 pu (or 0.55 pu), which is much higher (or lower) than the normal condition.

Therefore, this Taylor Series based conversion method can produce *ZIP* load models with high accuracy. It should be noted that the signs of the coefficients p_1, p_2, and p_3 can be negative, depending on the values of *kp* and *kq*. However, in terms of load flow studies, the *ZIP* model with negative coefficients can still be used to describe the voltage-demand relationship as long as the total power consumption is positive.

5.3.4 Load models for non-CLASS substations

WP1 has provided the exponential load models for the selected 60 CLASS primary substations. There are 7 out of 60 CLASS substations from the Stalybridge network. To investigate the demand reduction capability of the Stalybridge network, the load models of the other 21 non-CLASS substations have been estimated. Figure 5-5 illustrates the estimation process.

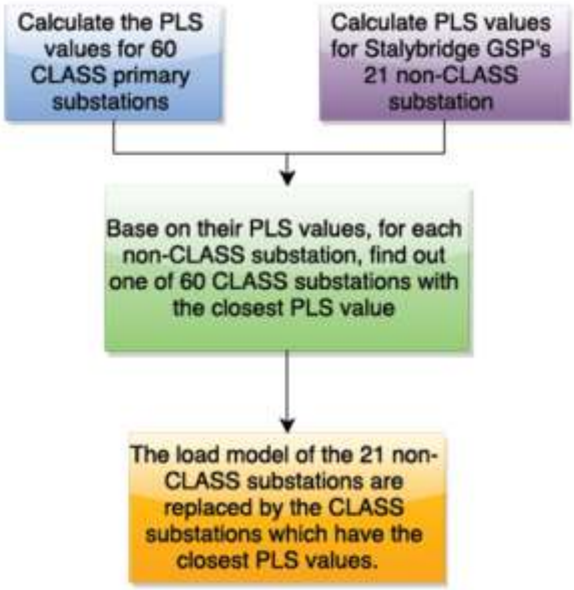


Figure 5-5: Load model estimation for non-CLASS substations in the Stalybridge network

For the 60 CLASS substations of WP1 and the 21 non-CLASS substations in the Stalybridge network, their domestic PLS values have been calculated based on the method presented in Section 4.3.2. According to the PLS values, the load model of a non-CLASS substation has been represented by the load model of the CLASS substation, which has the closest PLS value to the value of the non-CLASS substation. Finally, the estimated load models of the 21 non-CLASS substations and the load models of the 7 CLASS substations in the Stalybridge network form the complete load models.

5.4 Demand reduction studies with *ZIP* load models

With the converted *ZIP* load models and the load profiles developed in section 4.3.1, load flow studies have been carried out to assess the demand reduction capability of the Stalybridge network. During the simulations, the tap positions of all primary substation transformers have been reduced simultaneously, and the corresponding *P* reduction values have been measured at the GSP. According to the analysis of WP2-Part A, the maximum number of taps down has been set to 2 (i.e. up to 3% voltage reduction), in order to ensure that the downstream LV networks will not have voltage violations.

Figure 5-6 shows the network 24-hour *P* reduction capabilities in four seasons with tap down = 1 or 2. Comparing different seasons, winter has the largest demand reduction capability while summer has the least. The highest *P* reduction has occurred during the period from 17:00 to 20:00, while the lowest *P* reduction capability is from 2:00 to 6:00. Table 5-1 also summaries the maximum and minimum *P* reductions during a day for four seasons.

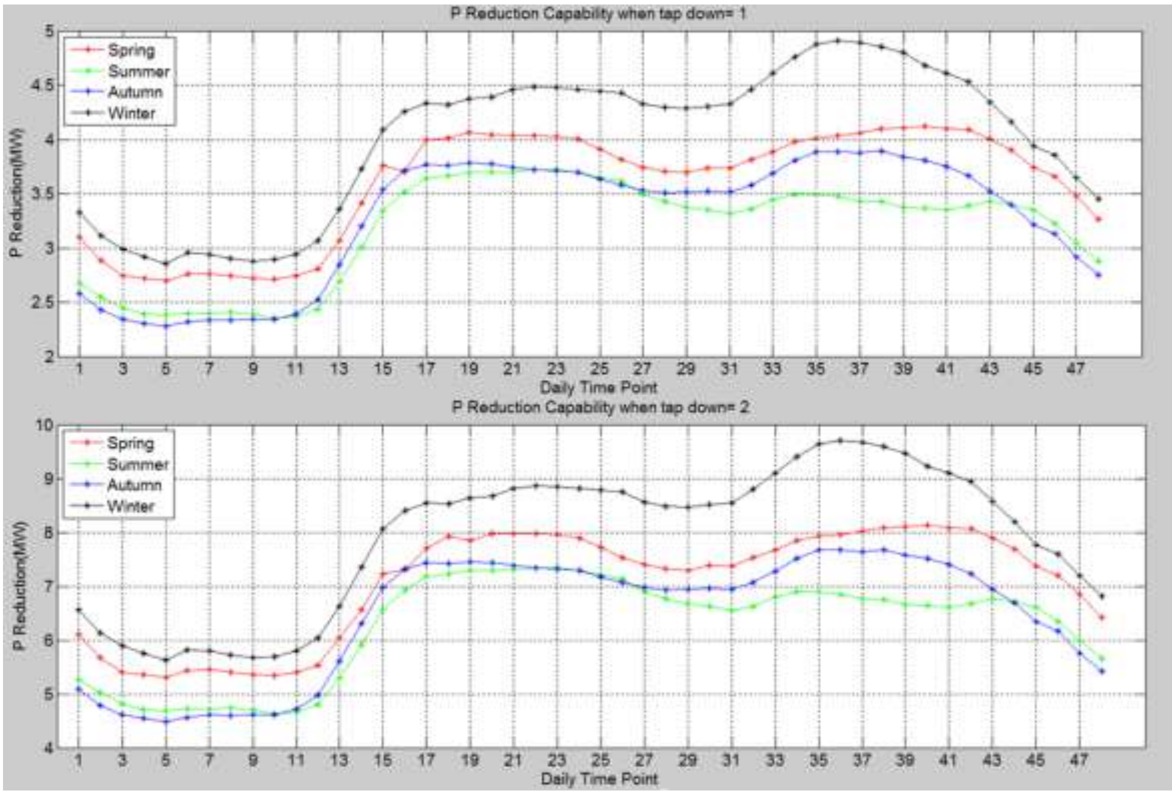


Figure 5-6: 24-hour *P* reduction capabilities of the Stalybridge network in four seasons

Table 5-1: Demand reduction capability of the Stalybridge network

Allowed max No. of taps down	Tap down = 1		Tap down = 2	
Demand reduction (MW)	Min	Max	Min	Max
Spring	2.695	4.119	5.309	8.127
Summer	2.351	3.722	4.629	7.348
Autumn	2.276	3.89	4.485	7.675
Winter	2.856	4.911	5.63	9.704

5.5 Summary

This section first presents the demand reduction capability of the Stalybridge network with fixed load models. Four load models (i.e. CZ, CI, CP and mixed load model of 50% CZ plus 50% CP) have been tested, respectively. The study results suggest that the voltage reduction should be within the range of 1%-4% (i.e. 1 to 3 taps down) to ensure no voltage violations in the EHV network.

The load models (developed from site trials) for 60 CLASS substations have been provided by WP1 in the form of exponential load models. To use the load models in OpenDSS, the exponential load models have been converted to *ZIP* models using Taylor Series. The load models of non-CLASS substations in the Stalybridge network have been represented by the load models of CLASS substations based on the PLS values. Finally, with the converted *ZIP* load models, the *P* reduction capability of the Stalybridge network has been investigated over the 24-hour period in a day and in four seasons. According to the results, winter generally has the largest *P* reduction capability among the four seasons since the load demand is highest in winter.

6 Conclusions

This report summarises the research work and the key outcomes of WP2-Part B of the CLASS project. The WP2-Part B aims to assess the Electricity North West reactive power absorption capability through the use of the tap staggering technique and to validate the estimated results with site trials. The operation of parallel transformers (at primary substations) with staggered taps can provide a means of absorbing reactive power. The aggregated reactive power absorption from many primary substation transformers could be used to mitigate the high voltage issues in the transmission grid during periods of low demand.

The objective of WP2-Part B is to carry out network reactive power absorption capability studies by developing accurate EHV network models with load profiles based on site measurements. In addition, WP2-Part B has estimated the demand reduction capability of the modelled Stalybridge network using the load models from WP1.

First, WP2-Part B has proposed a closed-loop control system for the tap staggering operation. The system consists of an EHV network model, the state estimation for the network observability of unmonitored substations and the tap stagger control method. A matrix database method has been developed to solve the tap stagger control problem. The method can determine how many transformers and staggered taps should be used according to the requirement of reactive power absorption.

The main achievements consist of three parts: (i) network modelling and conversion; (ii) reactive power absorption capability studies and validation of trial data; (iii) demand reduction capability study of the modelled EHV network.

(i) Network modelling and conversion

Two representative networks have been selected from the original EHV network model provided by Electricity North West. One is the South Manchester network with 102 buses and the other is the Stalybridge network with 222 buses. Each network model consists of a 132kV Grid Supply Point (GSP) and its downstream 33kV networks. In order to carry out time-series load flow studies, both networks have been converted from the original IPSA models to the OpenDSS models. The average error of the bus voltages calculated from the IPSA and OpenDSS models is around 0.01%.

(ii) Reactive power absorption capability studies and validation of trial data

For both the South Manchester and the Stalybridge networks, reactive power absorption capability studies have first been carried out with rated load demands. The studies aim to estimate the average reactive power absorption capability per primary substation. From the results, the reactive power absorption capability will increase with the number of staggered taps. In addition, the network loss introduced by tap stagger is much lower (e.g. 17 times smaller) than the reactive power absorption created.

Furthermore, to carry out time-series capability studies, the annual load profiles for all primary substations in the Stalybridge network have been developed based on site measurements. For each primary substation, the load profiles have been divided into four seasons. Each season has an average daily load curve with 48 points (i.e. half-hourly resolution). In addition, a load classification method based on the Peak Load Share (PLS) approach has been developed to estimate the load profiles of unmonitored substations. The method has been validated using the Stalybridge network model, with an average error of 10%.

With the seasonal load profiles, the reactive power absorption capability studies have been carried out in the Stalybridge network. The studies have investigated the reactive power absorption capability of the Stalybridge network over the 24-hour (48 × ½ hour) period in a day and in four seasons. Based on the results, the reactive power absorption capabilities of the Electricity North West network and the entire GB network have also been estimated. For each season, the reactive power absorption has changed over the 24-hour period. This is due to the variations of network demand. When the demand level is high, the network can provide more reactive power through the use of tap stagger. During the simulations, all primary substations can achieve up to Stagger = 3. However, for certain network loading, several substations cannot achieve Stagger = 4 or 5, due to their physical tap position limits.

The project has also carried out site trials to validate the effectiveness of the tap staggering technique. The validations have considered the tap stagger trials at a single primary substation (Dickinson Street) and in the Stalybridge network. For the Stalybridge network, seven primary substations have been selected to implement the tap staggering simultaneously. The corresponding reactive power variations at NG have been monitored, and the obtained data have been compared with the simulation results. The tap stagger validation of the Dickinson Street substation indicates an error of 0.275% between the simulated and monitored VAr absorption, with Stagger = 3. For the Stalybridge network validation, a method has been developed to process the NG data to mitigate the impacts of distribution network demand changes on the total VAr consumption observed at the GSP. The result shows an error of 3.06% between the simulated and the monitored VAr absorption, with Stagger = 3.

(iii) Demand reduction capability study of the modelled EHV network

Finally, the demand reduction capability of the modelled Stalybridge network has been investigated. Since OpenDSS cannot directly use the exponential load models derived from WP1, the exponential load models have been converted to *ZIP* models using Taylor Series. The results indicate that the maximum power consumption error between the exponential and the *ZIP* models is 0.0009% when ±6% voltage variation is considered.

With the converted *ZIP* load models, the demand reduction capability of the Stalybridge network has been studied. Based on the analysis from WP2-Part A, the studies have only considered the voltage reduction up to 3% (i.e. equivalent to two taps down of the primary substation transformers), which will not cause low voltage problems in the downstream LV networks. According to the results, winter generally has largest *P* reduction capability among the four seasons since the load demand is highest in winter.

In conclusion, the studies and analyses from WP2-Part B have quantified the reactive power absorption capability of the Electricity North West's network through the use of tap stagger. The outcomes have confirmed that the tap staggering technique has the potential to increase the reactive power demand drawn from the transmission grid. Further studies may consider the development of a real-time control system to demonstrate the effectiveness of the tap staggering method on mitigating transmission system high voltages.

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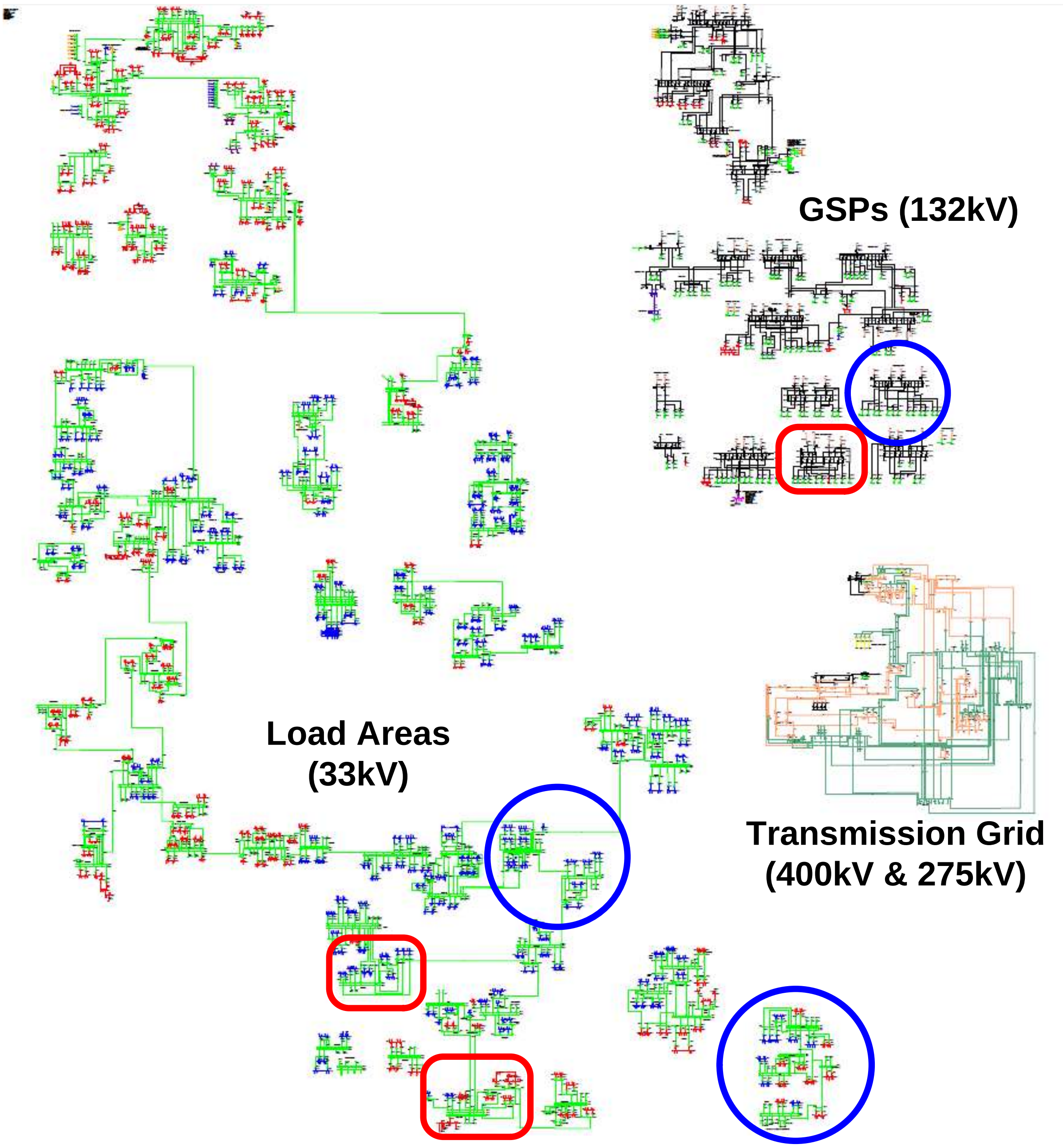
Appendix 1 EHV Network Model in IPSA



• Red boxes indicate the South Manchester GSP and its downstream 33kV networks.
• Blue circles indicate the Stalybridge GSP and its downstream 33kV networks.

Figure A: The overall Electricity North West EHV network model in IPSA

Appendix 2 South Manchester Network Model

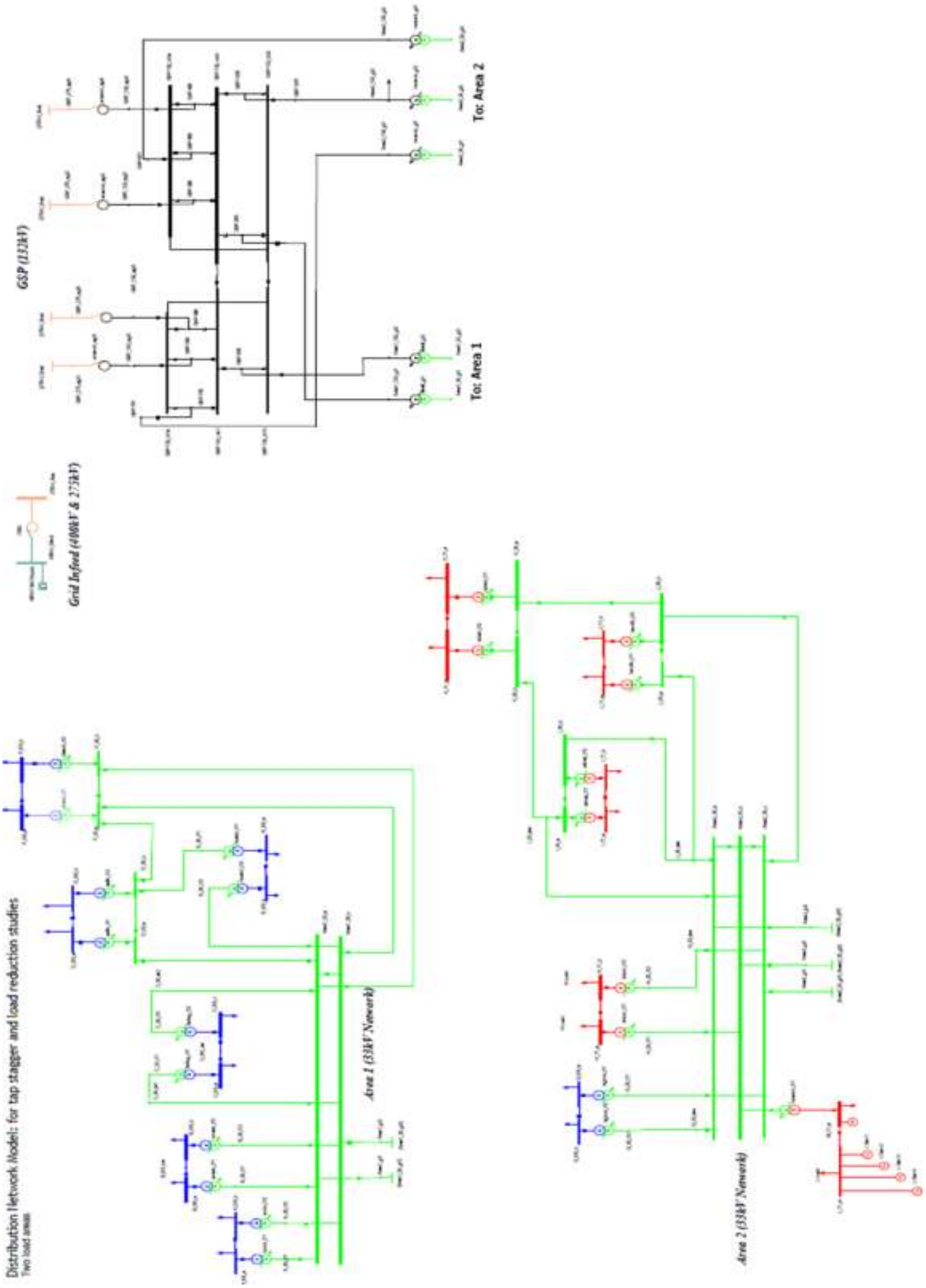


Figure B: Modified South Manchester network model based on the original IPSA model

Appendix 3 Stalybridge Network Model

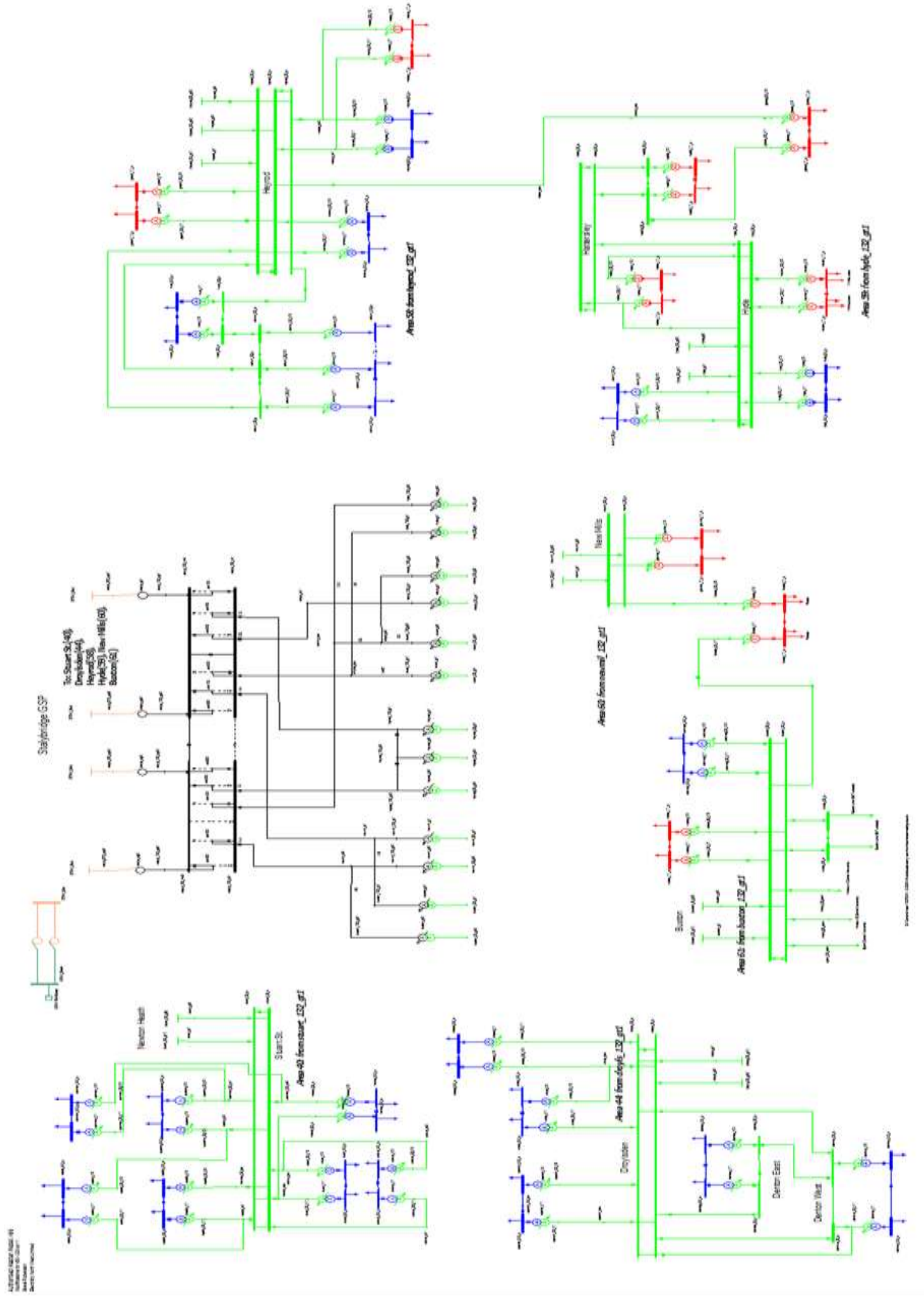


Figure C: Modified Stalybridge network model based on the original IPSA model

Appendix 4 Validation of South Manchester Network Model

1) Bus voltage comparison between the OpenDSS and IPSA models

Based on the South Manchester network shown in Figure B, the converted OpenDSS model and the IPSA model have been tested under the following four cases:

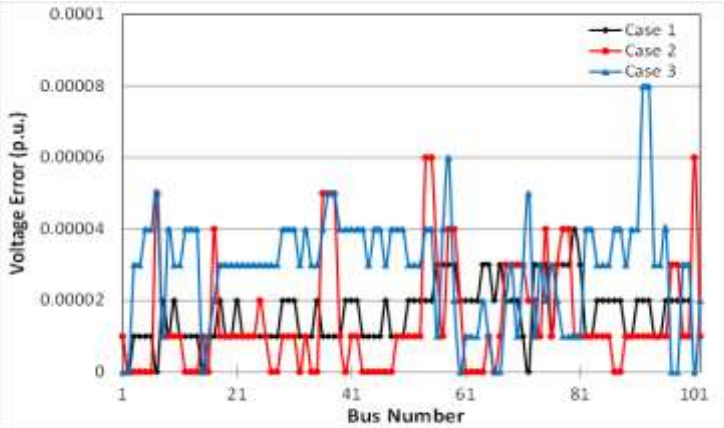
Case 1: Disabled the automatic voltage control for transformer voltages. Set the same tap positions in both the OpenDSS and IPSA network models. Disconnected the distributed generators to the network. These were the initial configurations for Case 2.

Case 2: Connected the distributed generators of total 23.8 MW to the network, and set the reactive power generation to zero.

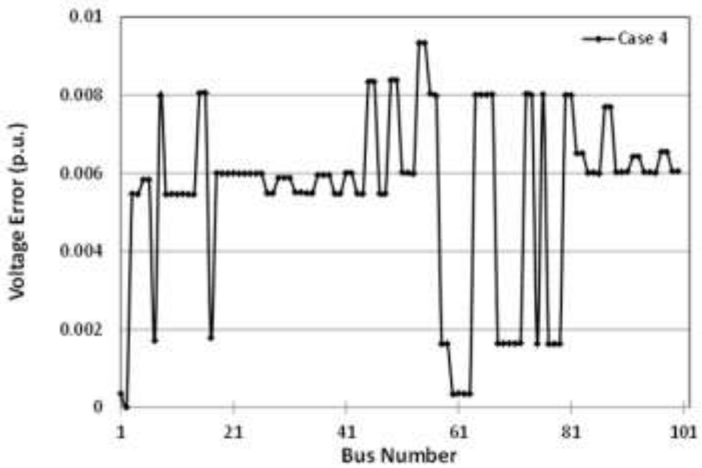
Case 3: Based on Case 2, increased the network load by 50% of its initial consumption.

Case 4: Enabled the automatic voltage control for transformer voltages. Set the same target voltages in both the OpenDSS and IPSA network models.

For each case, the errors between the bus voltages calculated from the OpenDSS and IPSA models are plotted in Figure D and summarised in Table A.



(a) Cases 1, 2, and 3



(b) Case 4

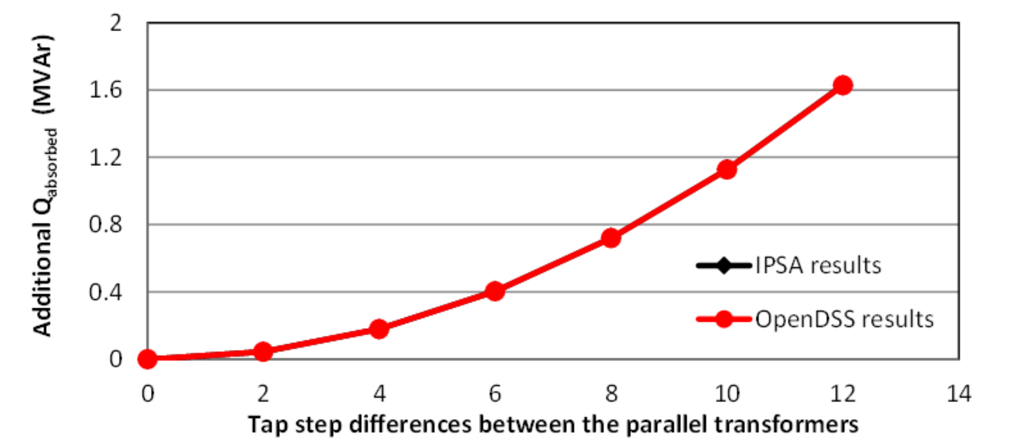
Figure D: Bus voltage differences between the OpenDSS and IPSA network models

Table A: Statistics of bus voltage differences between the IPSA and OpenDSS models

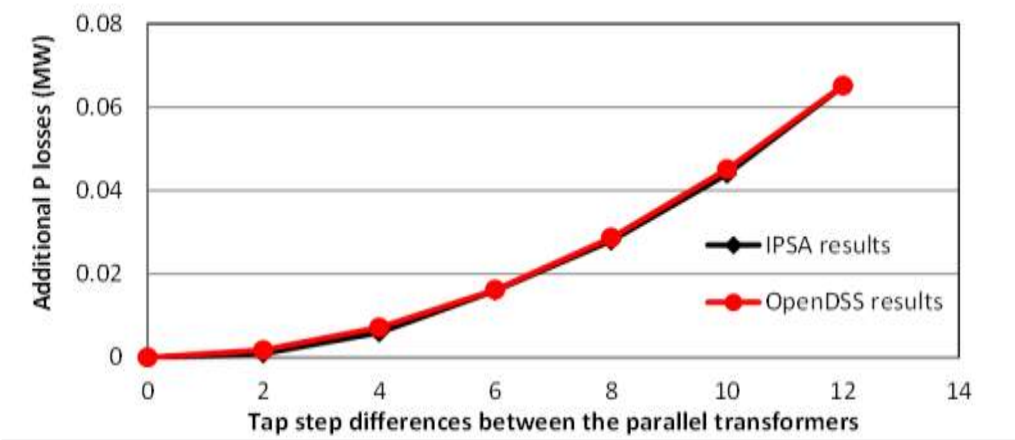
Voltage errors (pu)	Case 1	Case 2	Case 3	Case 4
Maximum	0.00004	0.00006	0.00008	0.00933
Average	0.000016	0.000014	0.000029	0.005488
Standard Deviation	0.000008	0.000015	0.000016	0.002312

2) Tap staggering result comparison between the OpenDSS and IPSA models

Figure E shows an example of the load flow result of a primary substation with tap stager. Table B also summarises the results calculated from the OpenDSS and IPSA models.



(a) Additional reactive power absorption of the parallel transformers



(b) Additional active power loss of the parallel transformers

Figure E: Comparison of tap staggering results between the OpenDSS and IPSA models

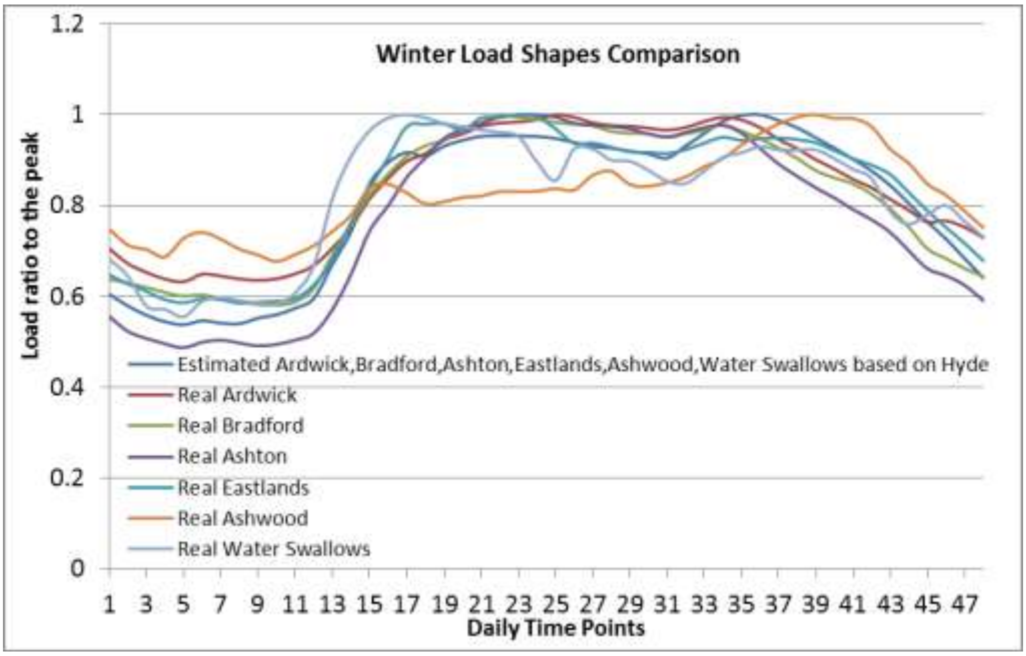
Table B: Additional *Q* absorption and *P* losses of two parallel transformers with tap stagger

33/6.6 kV Parallel Transformers with Rating = 23 MVA				
Tap Stagger[a]	**Additional $Q_{absorbed}$ (MVAr)**		**Additional P_{loss} (MW)**	
	OpenDSS	IPSA	OpenDSS	IPSA
0	0	0	0	0
1	0.0449	0.045	0.0018	0.001
2	0.1796	0.18	0.0072	0.006
3	0.4046	0.405	0.0162	0.016
4	0.7203	0.721	0.0287	0.028
5	1.1275	1.128	0.0451	0.044
6	1.6274	1.628	0.0651	0.065

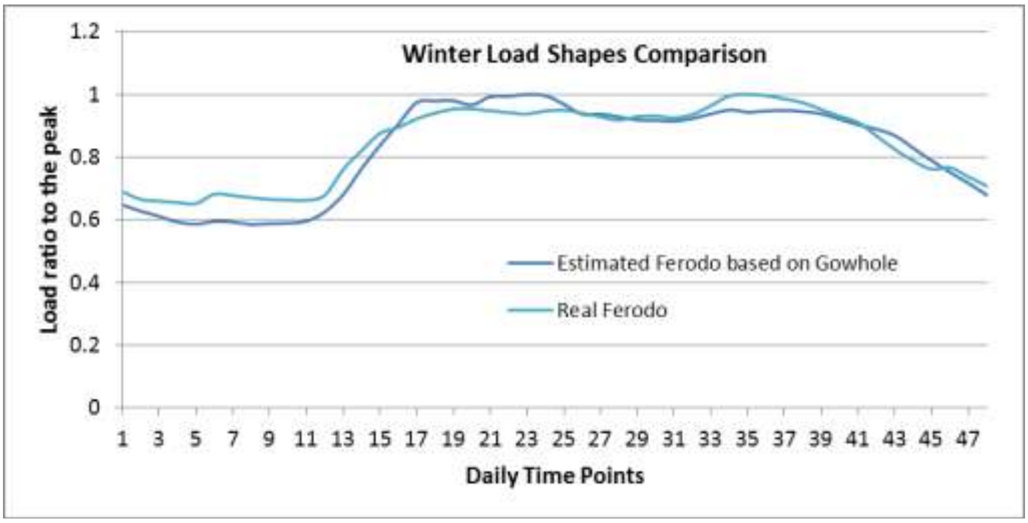
a. Stagger = n indicates that one transformer will increase its tap position by n steps and the other will decrease the tap position by n steps.

Appendix 5 Validation of Load Profile Estimation

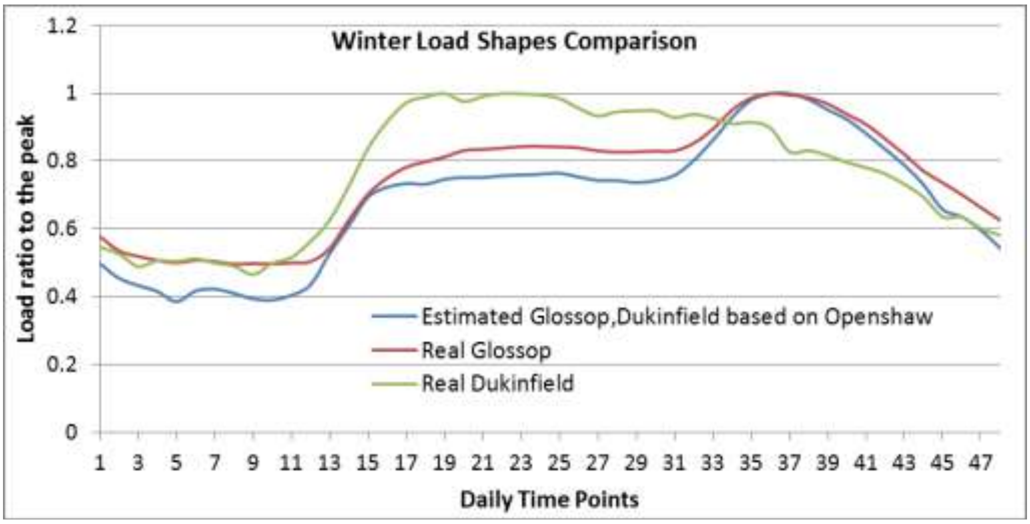
Figure F presents the comparison between the estimated and actual load shapes for the Stalybridge network.



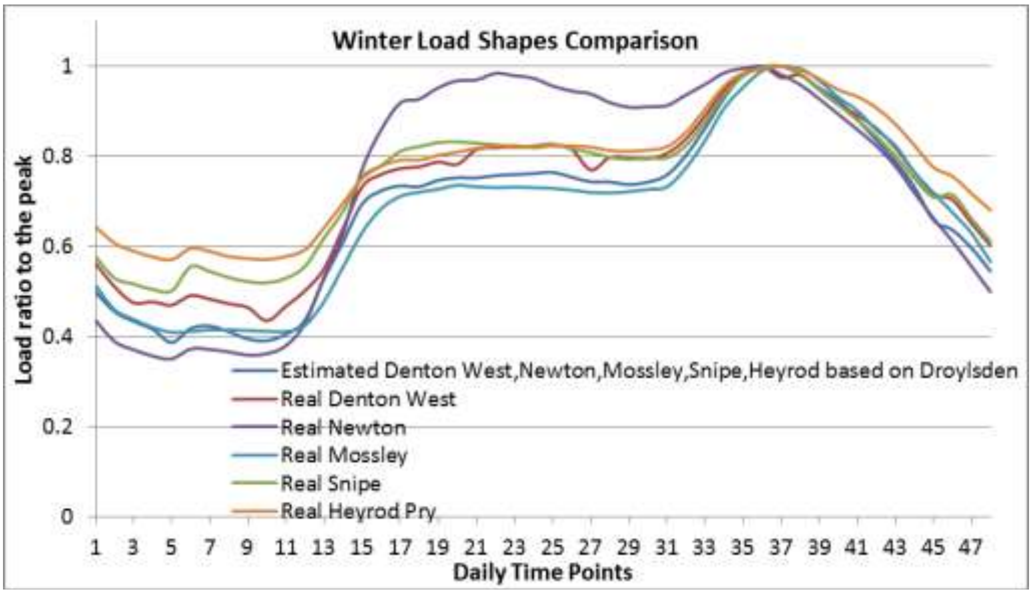
(a) Estimated load shape based on the Hyde substation



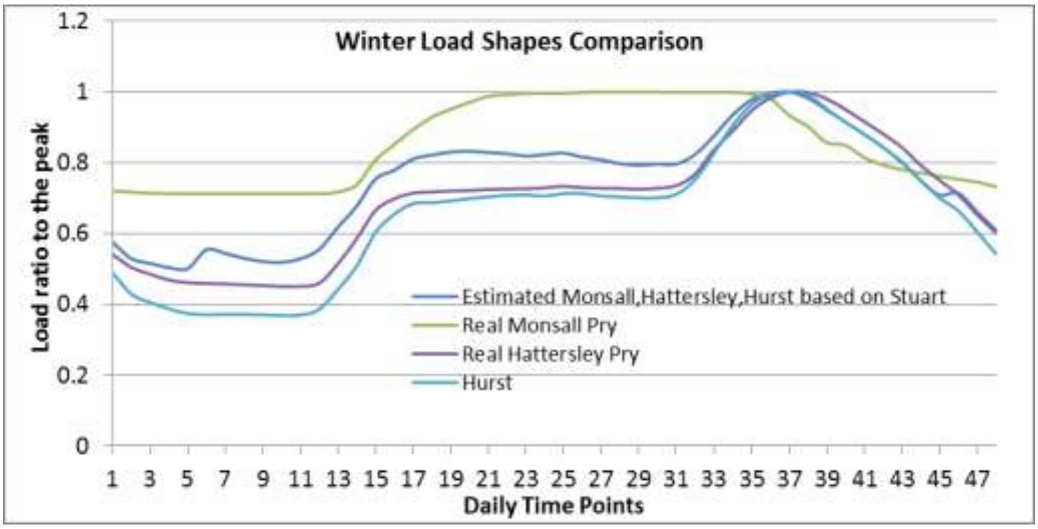
(b) Estimated load shape based on the Gowhole substation



(c) Estimated load shape based on the Openshaw substation



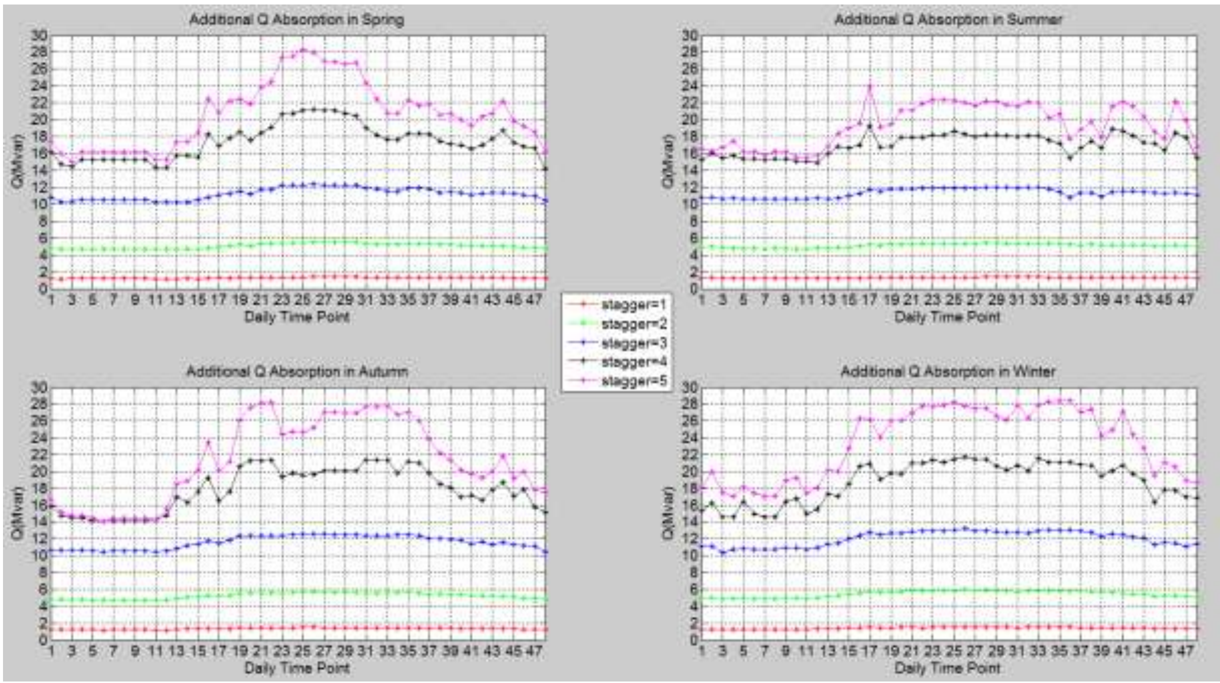
(d) Estimated load shape based on the Droylsden East substation



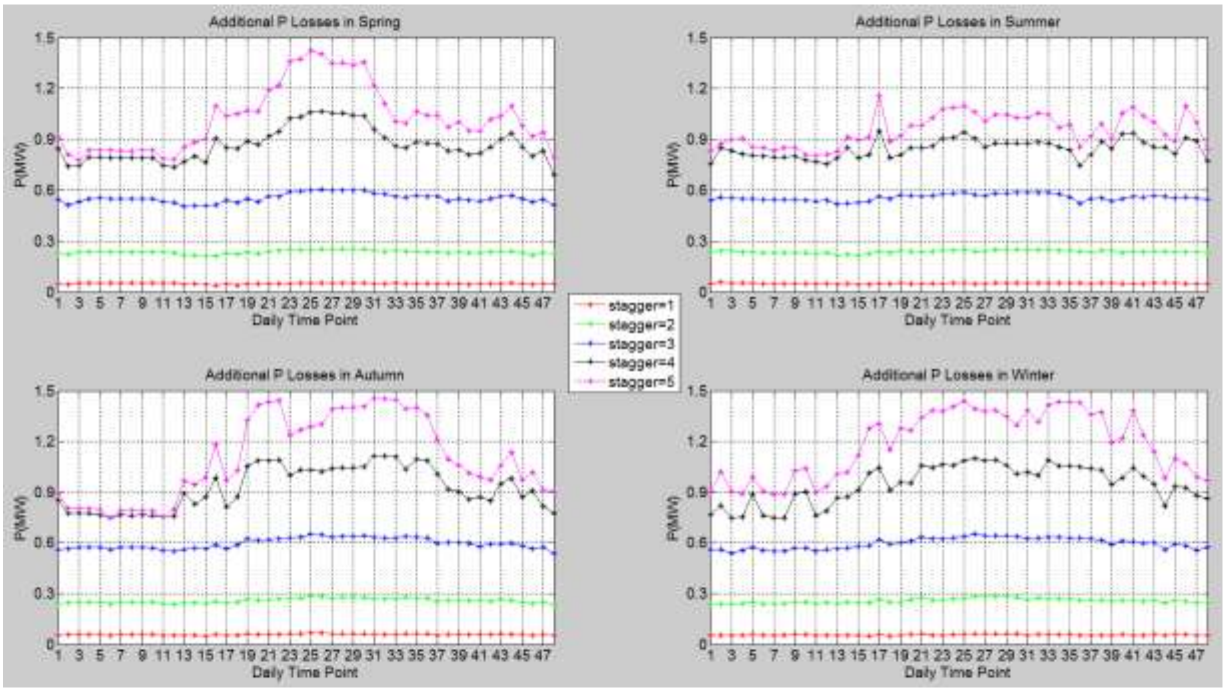
(e) Estimated load shape based on the Stuart substation

Figure F: Comparison of estimated and actual load shapes of the Stalybridge network

Appendix 6 Time-series Capability Studies of Stalybridge Network



(a) Network *Q* absorption capabilities



(a) Network *P* losses due to tap stagger

Figure G: 24-h capability studies for the Stalybridge network in four seasons