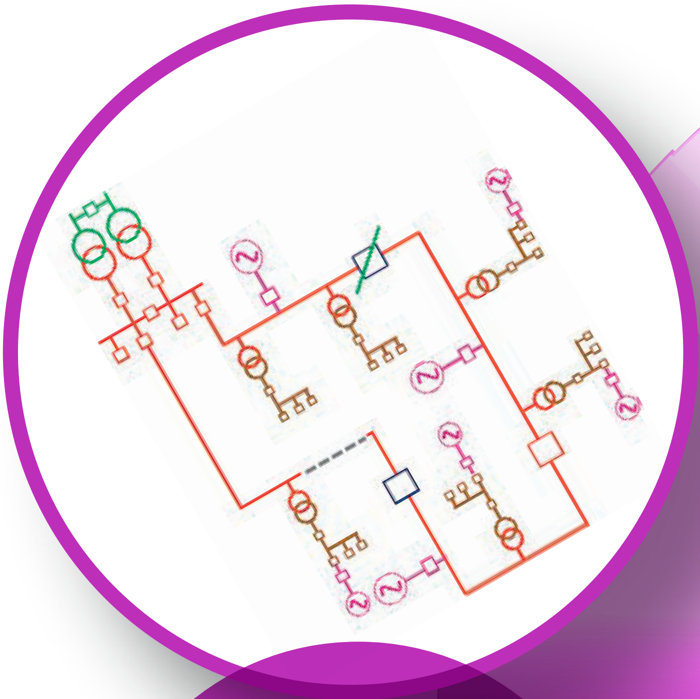
SP ENERGY NETWORKS

Flexible Networks for a Low Carbon Future



Network Reconfiguration Planning Methodology and Application Guide

July 2015

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1 Introduction

This methodology and application guide describes the actions necessary to assess the ability of load transfer based network control and/or automation to increase the capacity headroom in an 11kV distribution network, and to implement reconfiguration schemes which are considered beneficial. The process assumes that capacity headroom is constrained by the rating of one or more primary substations, although there may also be thermal and voltage constraints in the 11kV network.

The methods outlined here are based on those applied during the 'Flexible Networks for a Low Carbon Future' LCNF project, but have been generalised to address typical situations (particularly with respect to the scope of network monitoring) when evaluating the application of network automation to 11kV networks in general.

In this guide, an "11kV network" is a part of the 11kV distribution system, supplied from one or more primary substations, which is electrically continuous at 11kV. In loadflow analysis terms, such a network could be analysed using a single 11kV swing bus.

2 Summary of Assessment Process

The process of assessing the effectiveness of a potential load transfer scheme can be considered as a number of stages, in which reconfiguration options to release headroom are modelled and analysed in progressively more detail. At each stage, infeasible or unattractive options may be rejected from consideration. The main stages of analysis are as follows:

1. Analysis of primary substation load
2. Identification of load transfer options
3. Refinement of load models
4. Outline assessment, quantification and filtering
5. Detailed assessment, quantification and filtering, including
    a. Detailed analysis of specific points in time
    b. Voltage studies
    c. Reliability assessment
6. Selection of options for development and implementation

Each of these assessment stages, together with required data, is described in the following sections:

3 General Information Requirements

Information requirements can be divided into two categories:

1. Information about the distribution network
2. Information about the load

It is important to engage with network operators and planners at an early stage. This will enable the capture of local knowledge about the 11kV networks being considered, such as preferred backfeeding routes, the presence and characteristics of generation, and constraints on the operation of the network. It will also facilitate the engagement with the wider business necessary for selection and development of network reconfiguration options at the end of the analysis and filtering process.

3.1 Load Information

In all cases, load measurements should cover at least the most recent season in which the 11kV networks of interest have least capacity headroom. Normally, this would be expected to be winter, but may be affected by factors such as unusual load patterns and the use of seasonal equipment ratings. Where there is doubt, then data for the most recent 12 months should be used.

Measurements should be taken half hourly, or more frequently, and a common measurement interval selected for the analysis. Where a strong majority of measurements are taken more frequently, then remaining values may be interpolated to match. There is, however, little value in interpolating data from a large number of measurement points to match a few which are monitored at a higher sampling rate. Real and reactive power should be tabulated separately for each load point.

The need for additional temporary monitoring of HV feeder flows and HV customer and/or secondary substation load should be considered at an early stage in project definition. The information provide by this extra monitoring equipment may help to support Flexible Network Control scheme development and assessment by improving the understanding of HV network behaviour More capacity could therefore be released at lower risk. It is likely that next generation telecontrol systems will ultimately provide all of the information which is required for scheme design, assessment, and operation. However, if such equipment is not yet deployed in the 11kV networks of interest, a limited amount of additional monitoring may be helpful in reducing key uncertainties.

4 Assessment of Primary Substation Load Characteristics

The first stage of the analysis is to calculate and inspect the general seasonal, weekly and daily patterns of load, which should be done for each of the primary substations involved. This step will quantify the currently available capacity headroom at the primary substation from which load is to be transferred and at the other primary substations which might be involved. It will also allow different temporal patterns of load transfers to be assessed against the load profiles of the substations involved. Some load transfer options may be rejected at this stage. The resulting understanding of load behaviour will also be important in later stages of analysis.

4.1 Information Requirements

Primary transformer load measurements should be obtained for each of the substations which might potentially involved in load transfers. As mentioned previously, these should, at a minimum, cover the previous peak-load season at the substation from which load is to be transferred, but a full year should be obtained if possible. If available, historical data for up to the previous ten years should be obtained, to allow the most recent annual peak to be compared with longer-term trends and variations.

As discussed in the following paragraph, if mid-feeder HV measurements are available, they may be gathered to reverse the effect of historical network reconfigurations which transferred load between primary substations.

It is important that load data is filtered to remove not only erroneous measurements, but also measurements which reflect abnormal network configurations, such as the transfer of load from one primary substation or HV feeder to another for outage purposes. Where it is possible to do so (for example using mid-feeder measurements at auto-reclosers or other switching locations) the effect of these transfers may be 'reversed' by subtracting load from one substation or feeder and adding it to another – this is preferable to simply discarding the data point.

4.2 Analysis and Outcomes

First, the load duration curve for each primary substation of interest should be calculated, and the magnitude, date and time of the peak substation demand identified. Where historical data is available, the peak demand for preceding years should be identified and compared with the most recent data available to identify trends and assess the impact of weather. Probabilistic analysis can provide an improved indication of the underlying load growth and behaviour [1]. Where the most recent load peak is below average (perhaps because of a mild winter) scaling factors to average and maximum load over the longer period should be calculated. These statistics will give an initial impression of the capacity headroom in the 11kV network of interest, and will show which of the adjacent 11kV networks are likely to have spare capacity which can be used.

Average weekly load profiles for each primary substation should be calculated for the season of lowest capacity headroom in the 11kV network from which load is to be transferred. In such an average load pattern, the value of each point (e.g. 12:00 on Sunday) is the average of all corresponding points over the season. Inspection of these patterns will identify the days of the week on which each substation is usually most heavily loaded. Daily average load profiles should then be calculated for that day. Where similar loads occur on weekdays or weekend days, an average profile should be calculated for that class of day. In addition, single-day profiles should be calculated for each primary substation for the peak day(s) at the substation(s) from which load is to be transferred.

The profiles for the primary substations between which load is to be transferred can then be assessed to determine the periods during which it is desirable to transfer loads. Four classes of load transfer should be considered:

- **Permanent:** One or more sections of 11kV network are moved from one primary substation to another by permanently changing normally open points.
- **Seasonal:** The network configuration is changed twice a year to transfer load from a highly loaded substation to one with spare capacity. Such a mechanism is effective when additional capacity headroom is only required in part of the year, and minimises disbenefits (e.g. increased potential CI/CML) when it is not needed. Where the load profiles permit it and there are benefits in doing so, additional reconfigurations might be added around, for example, the Christmas holiday period.
- **Weekly:** Typically, a weekly load transfer might involve the network being configured differently on weekdays and at weekends.
- **Daily:** The network is reconfigured twice (or more often) per day so that load is transferred from a heavily loaded substation for the period around the daily peak. For example, primary substations with predominantly domestic load peaking in the evening transferring load to a primary substation with predominantly industrial and commercial load that peaks during working hours.

The latter two approaches are particularly attractive when the two primary substations involved in the transfer have significantly different load profiles, such as an evening peak and an overnight peak – load can be transferred from a substation which is at or close to peak load onto one which is lightly loaded in comparison to its daily peak and then returned as the peak of the second substation's demand approaches. Application of this transfer may be made dependent on short-term load forecasting, so that load is only transferred when there is a risk of capacity headroom being exhausted.

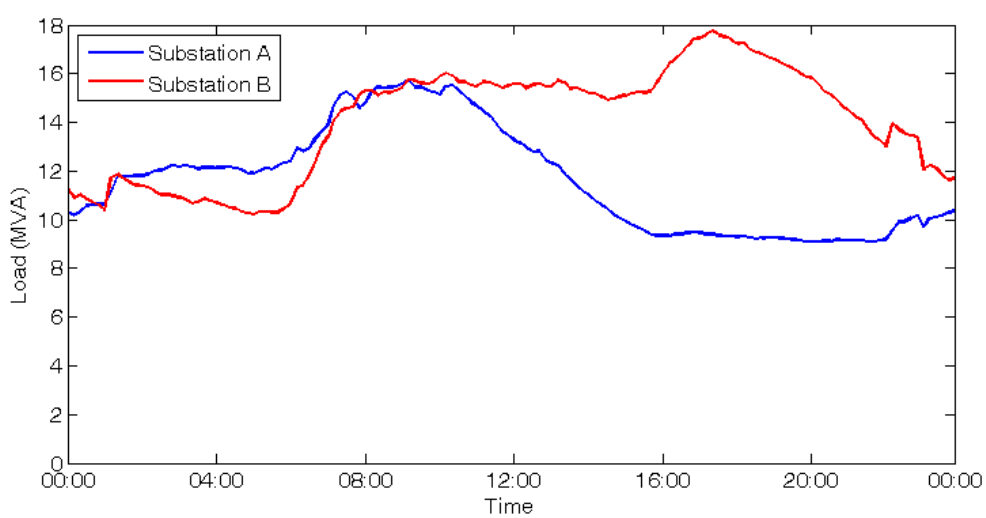


Figure 1: Load profiles offering potential for daily switching

Figure 1 shows a case in which a daily transfer of load from substation B to substation A between mid-afternoon and late-evening would have the effect of reducing the peak load on substation B by about 2MVA without increasing the peak load on substation A.

It may be desirable to analyse two or more temporal switching patterns for each set of primary substations between which loads could be transferred. These might include different classes of transfer, and/or variants of a class (e.g. different combinations of start and end time for a daily transfer).

It should be noted that technical constraints, such as the maintenance implications of frequent switching for network reconfiguration, may impose restrictions on the form of load transfer that can be adopted.

At this stage, infeasible transfers involving adjacent primary substations can be identified and removed from further consideration. Transfers should be considered infeasible where there is little or no available capacity headroom at the adjacent primary substation and no opportunity to apply periodic load transfers which do not increase the peak load at the adjacent substation.

5 Identification of Transferrable Network Sections

This stage of the analysis identifies sections of 11kV network which may be individually transferred, with their associated load, to adjacent networks. It also provides the opportunity to identify locations where it would be desirable to add additional remote control switchgear to provide increased network flexibility.

5.1 Information Requirements

This stage of the analysis requires a topological model of the 11kV network and of those parts of the adjacent networks which can be connected to it. This model should identify all remotely-controlled switchgear, and differentiate between those switches with a protective function and those without. This requirement might be satisfied by a suitable AC or DC loadflow model, which would fulfil the requirements of the more detailed analysis described below. However, a simpler source of information, such as a diagram derived from a distribution management system or other Control Room source would also be suitable.

More general information on the protection of the power network should also be obtained, to identify the location, capabilities and settings of the protective devices applicable to relevant sections of network before and after transfer.

5.2 Analysis

The topological model of the 11kV network from which load is to be transferred should be used to identify existing and planned locations of remote-controlled switchgear. Locations at which it would be advantageous to install additional remote-controlled switchgear should also be considered, if local knowledge of the distribution of load along a feeder suggests that it would be beneficial. Such a need may also be identified as a result of the analysis and apportionment of feeder load, as described below.

Mutually adjacent sets of remote-controlled switches define sections of network (and groups of secondary substations and/or HV customers) which can be transferred, in order, to adjacent primary substations, as shown in Figure 2, in which transferrable network sections are labelled T1–T8:

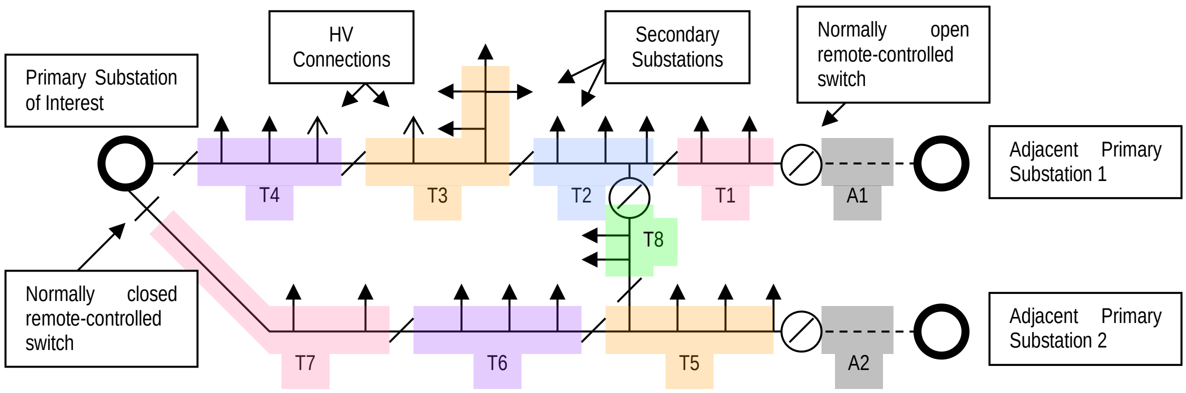


Figure 2: Identification of transferrable network sections

As can be seen in Figure 2, it may be possible to transfer some sections of network onto a choice of adjacent primary substations. This can produce a significant degree of complexity in the sequence of load transfers, particularly when more than one or two sections of network are to be transferred. In Figure 2, the first section which can be transferred to primary substation 1 is T1, which must always be followed by T2. Thereafter, either T3 or T8 may be transferred, followed by T4 or T8 if T3 is transferred, or by T5 or T3 if T8 is transferred. This complexity should be explored in more detail once the load in each transferrable section has been quantified, as discussed in section 6. At this stage it is sufficient to document the boundaries of each transferrable section and the secondary substations and HV connected customers within it.

When selecting candidate network sections for transfer, care should be taken to appropriately exploit remote controlled switches with and without a protective function. By placing open points at non-protective switches, network reliability is likely to be increased, since protection operation will tend to isolate smaller sections of network, as shown in Figure 3:

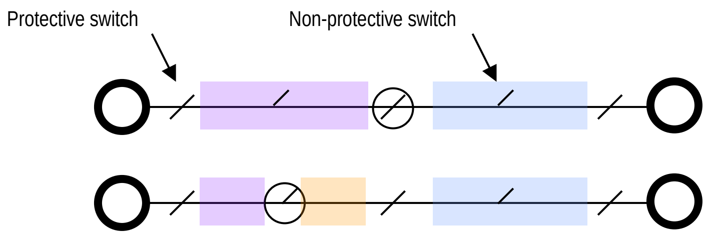


Figure 3: Placement of open point influences size of fault-affected area

With the open point placed at the non-protective switch, a fault between the left-hand substation and the mid-point switch affects half of this feeder section. However, with the open point at the mid-point protective switch, such a fault will trip the entire section from the substation to the open point. This effect can be explored further (and evaluated against increased headroom which might be available) through more detailed modelling, as described in section 7.

5.3 Protection Constraints

Technical constraints on the use (rather than capacity) of alternative supply paths should also be explored at this stage. A particular issue which should be considered is the protection of the network, particularly where a mixture of underground and overhead feeder sections exists. Consider a situation in which, in the portion of network shown in Figure 2, sections T8 and A2 are completely composed of underground cable, while section T5 is overhead. In the 'current' configuration of normally open points shown, it is likely that the feeder circuit breaker at primary substation 2 would not auto-reclose, since any cleared fault would be likely to be a permanent cable fault. Following the transfer of section T5, a significant proportion of the faults on this feeder will be transient overhead line faults, for which auto-reclosure is desirable. It is therefore necessary to either modify the protection at primary substation 2 so that auto-reclosure takes place (optionally with a sectionaliser to switch out section T5 in case of a permanent fault) or to add an auto-recloser at the current normally open point, coordinated with the protection at primary substation 2. Transfer of section T8 may require that a further protective device is added at the boundary with section T5 to ensure that auto-reclosure onto a fault in this section does not take place.

In general then, it should be checked that the existing protection system is suitable for the changes in power flow envisaged:

- In terms of clearing permanent and transient faults in overhead and underground sections.
- In terms of co-ordination under the different directions of fault current flow foreseen.
- In terms of margin between overcurrent settings and expected levels of circuit load current flow.

Where the protection is unsatisfactory then modification of settings and/or addition and replacement of protection devices should be considered in order to permit the implementation of the desired network reconfigurations.

6 Localisation of HV Network Load

This stage of the analysis prepares load data for use in the two following analysis stages. In order to assess the effects of load transfer on primary substation capacity headroom, it is necessary to model the total active and reactive load of secondary substations and HV customers in each transferrable section of network. To assess the feasibility of transfers in terms of thermal and voltage constraints the load must be subdivided to the level of individual secondary substations and HV connections. At this stage, sections of network can be identified in which it would be advantageous to install additional remote-controlled switches for added flexibility. This step can supplement any identifications made on the basis of local knowledge, as discussed above.

The outline analysis described in section 7 can be achieved with a more granular localisation of network load than the detailed analysis in section 8. However, with the exception of one particular form in which load data may be available, it is necessary that the load should be allocated in a more detailed way (as for the detailed analysis) and then aggregated for outline analysis. This is discussed in more detail below.

6.1 Information Requirements

Only data relevant to the HV feeders of interest which have not been discounted at earlier stages of analysis need be gathered. Where available, measured secondary substation and HV customer load data should be used. However, it is recognised that it is unlikely that all secondary substations and HV customers connected to the 11kV feeders of interest will be monitored. For example, pole-mounted secondary substations are rarely monitored. Therefore, available data should be supplemented using primary substation measurements of HV feeder flow, as described in section 4.1, and where available mid-feeder measurements of power flow. HV customer metering data may also be used to supplement other measurements. It will generally be necessary to know the type (i.e. pole or ground mounted), rating and (where fitted) MDI reading for each secondary substation.

Where no secondary or HV customer load measurements are available, then per-feeder flow measurements at the primary substation and (where available) mid-feeder points should be used, together with HV customer metering data, and localised as described in section below.

A number of permutations of load data availability are possible:

1. All secondary substations and HV customers are monitored or otherwise have available load time series data (such as from metering data).
2. All potential switching points provide power flow data. Some or all secondary substations and/or HV connections are unmonitored.
3. Feeder flow data is available from the primary substation. Some potential switching points provide power flow data. Some or all secondary substations and/or HV connections are unmonitored.
4. Feeder flow data is available from the primary substation. No potential switching points on one or more feeders provide power flow data; some or all secondary substations are unmonitored.

It should be noted that load data availability may change among these four cases, either as a result of a programme of substation monitor installation, or as a result of intermittent monitor or communication unreliability.

In the case where power flow data is available from all potential switching points on a feeder for the entire period of interest, then outline assessment of reconfiguration options on that feeder (section 7) may be done on the basis of this information alone, with no need for consideration of secondary substation or HV metering data. The outline assessment may lead to the rejection of some reconfiguration options. The load allocation described in this section should then be carried out only for those HV feeders relevant to the remaining reconfiguration options.

6.2 Load Localisation Process

A load allocation method will generally have the following steps:

1. Identification of network sections within which load must be distributed
2. Separation of known and unknown load
3. Allocation of unknown load to unmonitored secondary substations and HV customers

Where the total load within a section of network (bounded by measurement points and open points) is known, then that section can be treated in isolation from the perspective of load allocation. Consider again the network from Figure 2 in which measurement points are annotated 'M':

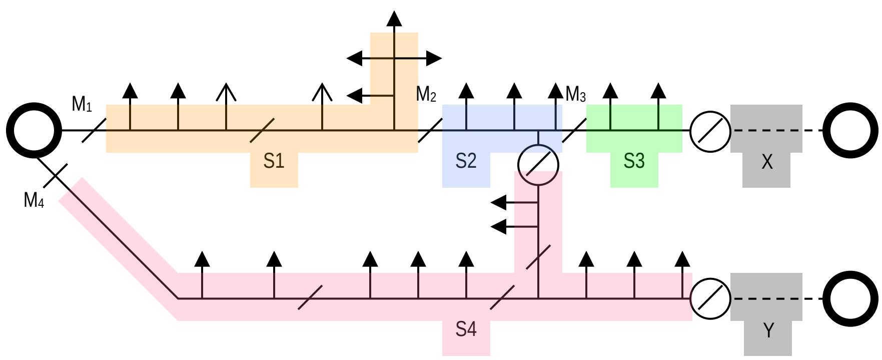


Figure 4: Identification of network sections for load allocation

Four sections S1 – S4 are identified. It should be noted that that number and boundaries of these sections may change depending on the availability of measurements (which might vary over time), and on network reconfigurations involving changes in the location of open points.

For each section, the active and reactive power to be allocated at any point in time are defined as the difference between inflow and outflow for the section at that time. For section S2 in Figure 4, the power to be allocated is defined as:

$$P_{S2}(t) = P_{M2}(t) - P_{M3}(t),\ Q_{S2}(t) = Q_{M2}(t) - Q_{M3}(t) \qquad (1)$$

If:

- all of the measurements $\{P_{Mi}(t),Q_{Mi}(t)\}$ on a feeder are known throughout the period of interest, and
- the measurement points *Mi* on the feeder correspond to *all* of the switching points which can be used for reconfiguration of that feeder,

then the outline assessment described in section 7 can proceed for that feeder on the basis of the results from equation (1). If reconfiguration options involving that feeder are not discounted by the outline assessment, then load localisation for the detailed assessment stage should resume at this point for that feeder.

If not all of the measurements $\{P_{Mi}(t),Q_{Mi}(t)\}$ for a feeder are known, then localisation should continue for that feeder as described in the remainder of this section.

For section S4 (a complete feeder, bounded only by the primary substation circuit breaker and open points), the load to be allocated is simply the measured feeder load:

$$P_{S4}(t) = P_{M4}(t)\,,\; Q_{S4}(t) = Q_{M4}(t) \qquad (2)$$

Where secondary substations and HV connections whose load is monitored are supplied from a network section, the load for that section can be categorised as 'monitored' and 'unmonitored'. Consider section S1 from Figure 4, where monitored secondary substations are annotated 'X', unmonitored secondary substations are annotated 'U', monitored HV connections are annotated 'Y' and unmonitored HV connections are annotated 'V':

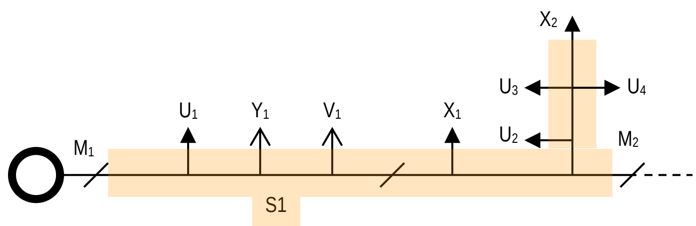


Figure 5: Monitored and unmonitored secondary substations fed from HV network section

Unmonitored HV connections should be considered first. Metering data has been used to provide 'pseudo-measurements' for these points. Where the metering data measurement interval is longer than the interval selected for the analysis (as mentioned in section 3.2), then the HV connection load is assumed to be constant over the measurement interval. This approach is preferred to interpolation between points, since metering data is usually expressed as an energy value, corresponding to the average load over the interval. Interpolation would tend to add further smoothing to the HV connection's load profile, which is considered undesirable, and does not improve the quality of the data. This process produces pseudo-measurements $\{P_{Vi}(t), Q_{Vi}(t)\}$ for each unmonitored HV connection.

In Figure 5, the unmonitored active and reactive power are defined as the difference between the total section load and the load which is observed at monitored secondary substations, and all HV connections.

$$P_{S1,U}(t) = P_{S1}(t) - \sum_{j=1}^{3} P_{Xj}(t) - P_{Y1}(t) - P_{V1}(t) \tag{3}$$

$$Q_{S1,U}(t) = Q_{S1}(t) - \sum_{j=1}^{3} Q_{Xj}(t) - Q_{Y1}(t) - Q_{V1}(t) \tag{4}$$

In general, for an HV network section S_i with N_{Xi} monitored secondary substations, N_{Yi} monitored HV connections and N_{Vi} unmonitored HV connections, the unmonitored load is:

$$P_{Si,U}(t) = P_{Si}(t) - \sum_{j=1}^{N_{Xi}} P_{Xj}(t) - \sum_{k=1}^{N_{Yi}} P_{Yk}(t) - \sum_{l=1}^{N_{Vi}} P_{Vl}(t) \tag{5}$$

$$Q_{Si,U}(t) = Q_{Si}(t) - \sum_{j=1}^{N_{Xi}} Q_{Xj} - \sum_{k=1}^{N_{Yi}} Q_{Yk}(t) - \sum_{l=1}^{N_{Vi}} Q_{Vl}(t) \tag{6}$$

Once the unmonitored load for a network section has been calculated it must be allocated to individual secondary substations and HV connections. This has been achieved using a fixed allocation factor k for each secondary substation:

$$P_{Uj}(t) = k_j P_{Si,U}(t), \; Q_{Uj}(t) = k_j Q_{Si,U}(t) \tag{7}$$

In the absence of more detailed information, the allocation factors can be calculated on the basis of the rated capacity of the secondary substations supplied from each feeder:

$$k_j = \frac{S_{rated,j}}{\sum_{n=1}^{N_{Ui}} S_{rated,n}} \tag{8}$$

In practice, more detailed information is often available in the form of Maximum Demand Indicators (MDI), typically installed at ground mounted substations. A method based on a secondary substation load estimation method used by SP Energy Networks has been applied, in which an initial estimate $S_{est,j}$ is made of the load on secondary substation at secondary substation j at the time of primary substation peak:

$$S_{est,j} = \begin{cases} 0.8S_{MDI,j} & : \quad Ground-mounted \\ 0.2S_{rated,j} & : \quad Pole-mounted \end{cases} \tag{9}$$

These initial estimates are then refined based on a comparison of measured and modelled feeder voltage profiles, as described further in [2]. Allocation factors are then calculated from these estimates:

$$k_j = \frac{S_{est,j}}{\sum_{n=1}^{N_{Ui}} S_{est,n}} \tag{10}$$

Finally, time series of load for each unmonitored secondary substation are calculated:

$$P_{Uj}(t) = k_j P_{Si,U}(t),\ Q_{Uj}(t) = k_j Q_{Si,U} \tag{11}$$

7 Outline Assessment of Transfer Options

The objective of this stage of the assessment is to filter out reconfiguration possibilities which are clearly infeasible, and to identify feeder and substation load peaks for more detailed analysis. In order to fully assess the feasibility and effectiveness of the network reconfiguration options identified as described in section 5, it will be necessary to carry out load flow studies at specific times of interest, specifically:

- The times of the peaks of the primary substation and feeder from which load is transferred.
- The times of the peaks of the primary substation and feeder to which load is transferred.

Depending on the amount of load being transferred, and the period for which the transfer is made (i.e. part of each day, part of each week, seasonally or permanently), it is possible that the time at which one or more of these peaks occurs is changed by the reconfiguration. It is therefore advisable to evaluate all of the times within the period when the peaks might occur (typically the winter season) to determine when these peaks occur under different reconfigurations. Such an evaluation must, of necessity be simple, since the number of evaluation cases (measurement instants and network configurations) will be large, and thus a second, more detailed assessment of cases of particular interest is required afterwards.

7.1 Data Requirements

Information is required about the topology of the network and the loads connected to it. For feeders meeting the conditions set out under equation (1) above, the topological information should specify the sequence of switches along the feeder, and identify the corresponding measurements. The load information should consist of the time series $\{P_{Si}(t),Q_{Si}(t)\}$, as specified in equation (1), and the real and reactive power time series for the interconnecting feeder at the adjacent primary substation.

For feeders which do not meet the conditions set out under equation (1) above, the network topology should show the sequence of switching points, and the load points (secondary substations and HV connections) between them. The load information should consist of the time series $\{P_U(t),Q_U(t)\}$, $\{P_V(t),Q_V(t)\}$, $\{P_X(t),Q_X(t)\}$ and $\{P_Y(t),Q_Y(t)\}$, as defined in section 6 above, for all of the secondary substations and HV connections supplied from the feeder.

In both cases, the load data should cover the season in which the peak load occurs for the substation from which load is to be transferred.

The topological model should include the minimum rating of the main line of the feeder between each pair of switching points. Consider the section of feeder shown in Figure 6, in which the ratings (in MVA at nominal voltage) of each section are shown:

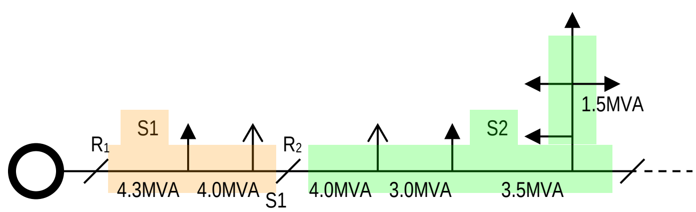


Figure 6: Example of minimum feeder section ratings

In this case, the minimum rating of section S1 is 4.0MVA, while the minimum rating of section S2 is 3.0MVA. The 1.5MVA rating of the spur from section S2 is not considered, since the flow in this spur will not be significantly affected by load transfers.

7.2 Outline Assessment

The outline or initial assessment is based on a simple arithmetic model of power flow in the network. Consider again the HV network fragment shown in Figure 2:

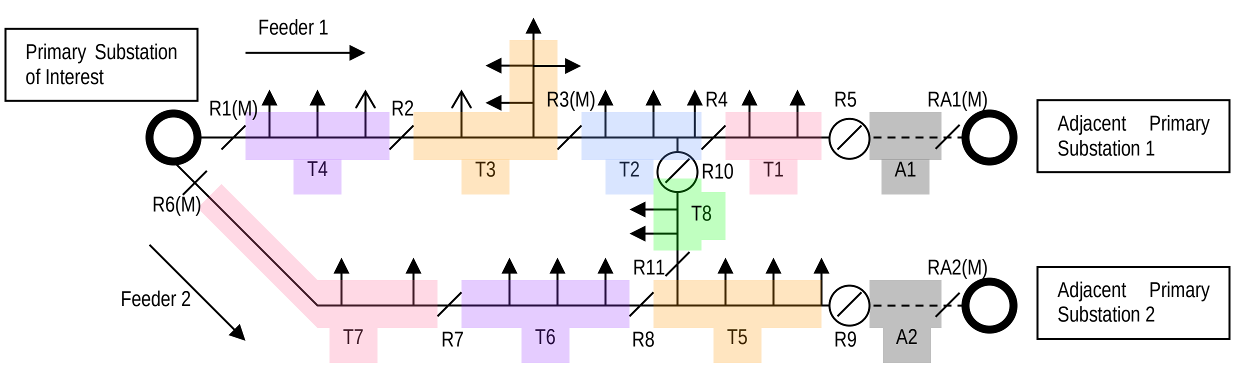


Figure 7: Example HV network for outline assessment

As before, the transferrable network sections are labelled T1–T8. Sections of network normally supplied from adjacent primary substations are labelled A1 and A2. Remotely controlled switches are labelled R1–R11; those for which power flow measurements are available are suffixed '(M)'. RA1 and RA2 are the feeder circuit breakers at the adjacent primary substations.

The first step of the analysis is to calculate the time series of active and reactive load for each transferrable section, defined as the sum of monitored and unmonitored load in that section:

$$P_{Ti}(t) = \sum_{U_j \in T_i} P_{Uj}(t) + \sum_{V_k \in T_i} P_{Vk}(t) + \sum_{X_l \in T_i} P_{Xl}(t) + \sum_{Y_m \in T_i} P_{Ym}(t) \tag{12}$$

$$Q_{Ti}(t) = \sum_{U_j \in T_i} Q_{Uj}(t) + \sum_{V_k \in T_i} Q_{Vk}(t) + \sum_{X_l \in T_i} Q_{Xl}(t) + \sum_{Y_m \in T_i} Q_{Ym}(t) \tag{13}$$

where $U_j \in T_i$ denotes the unmonitored secondary substations supplied from network section T_i. For feeders meeting the conditions given under equation (1) above, the real and reactive load in each section is directly known, and equations (12) and (13) can be replaced by:

$$P_{Ti}(t) = P_{Si}(t) \tag{14}$$

$$Q_{Ti}(t) = Q_{Si}(t) \tag{15}$$

Secondly, for each feeder, the sequence in which transferrable sections might be transferred to the adjacent primary substation is determined. For feeder 1, this is T1, T2, T3, T4. However, the interconnection to feeder 2 via section T8 introduces a complication, since T8 may also be transferred at any stage after the transfer of T2, and T5 and upstream sections of feeder 2 may then be transferred. In practice it is likely that sections of feeder 2 will transfer via section A2, but it is certainly worthwhile to evaluate the transfer to T8 with feeder 1, and possibly T5 also. Local knowledge of network behaviour and constraints during backfeeding can provide guidance. A table of configurations to be studied for each feeder can therefore be written. For feeder 1 in Figure 7, this is:

Stage	Open Point	Feeder 1 main line only	Feeder 1 + T8	Feeder 1 + T8 + T5
0	R5	(base case)		
1	R4	T1		
2	R3	T1,T2	T1,T2,T8	T1,T2,T5,T8
3	R2	T1,T2,T3	T1,T2,T3,T8	T1,T2,T3,T5,T8
4	R1	T1,T2,T3,T4	T1,T2,T3,T4,T8	T1,T2,T3,T4,T5,T8

Table 1: Example table of load transfer steps

For each pair of feeders, the daily and weekly average load profiles, as well as the peak day load profiles should be compared to determine which of the temporal patterns of reconfiguration discussed and selected in section 4 are appropriate. A set of power flow time series should be calculated for each of these temporal patterns and for each tabulated network configuration, as discussed in the following paragraphs.

Firstly the active, reactive and apparent power load time series for the primary substation P from which load is transferred and the adjacent primary substation A to which it is transferred should be determined:

$$P_{P,Ci}(t) = P_{P,base}(t) - \sum_{T_j \in C_i} P_{Tj}(t)\,,\; Q_{P,Ci}(t) = Q_{P,base}(t) - \sum_{T_j \in C_i} Q_{Tj}(t)\,,\; S_{P,Ci} = \sqrt{P_{P,Ci}^2 + Q_{P,Ci}^2} \quad (16)$$

$$P_{A,Ci}(t) = P_{A,base}(t) + \sum_{T_j \in C_i} P_{Tj}(t)\,,\; Q_{A,Ci}(t) = Q_{A,base}(t) + \sum_{T_j \in C_i} Q_{Tj}(t)\,,\; S_{A,Ci} = \sqrt{P_{A,Ci}^2 + Q_{A,Ci}^2} \quad (17)$$

where *base* denotes the load in the base case without load transfers, and $T_j \in C_i$ denotes those sections transferred under configuration C_i. The expected power flow time series at each switch R_k through which power flows from the adjacent substation under the new configuration C_i is also calculated. These represent boundary conditions of network sections which may experience increased current flows under the new configuration:

$$P_{Rk,Ci}(t) = \sum_{T_j \in C_i, T_j \leftarrow R_k} P_{Tj}(t)\,,\; Q_{Rk,Ci}(t) = \sum_{T_j \in C_i, T_j \leftarrow R_k} Q_{Tj}(t)\,,\; S_{Rk,Ci} = \sqrt{P_{Rk,Ci}^2 + Q_{Rk,Ci}^2} \quad (18)$$

where $T_j \leftarrow R_k$ denotes transferrable sections lying 'downstream' of R_k following the load transfer. In addition, the flow through the feeder circuit breaker *RA* at the adjacent primary substation is calculated:

$$P_{RA,Ci}(t) = P_{RA,base} + \sum_{T_j \in C_i} P_{Tj}(t)\,,\; Q_{RA,Ci}(t) = Q_{RA,base} + \sum_{T_j \in C_i} Q_{Tj}(t)\,,\; S_{RA,Ci} = \sqrt{P_{RA,Ci}^2 + Q_{RA,Ci}^2} \quad (19)$$

The following metrics should then be extracted from these time series:

- The magnitude and time of the peak load at the primary substation of interest *P*
- The magnitude and time of the peak load at the adjacent primary substation *A*
- The magnitude and time of the peak flow through each primary substation feeder circuit breaker.
- The magnitude of the peak flow through each remote controlled switch which experiences power flow from the adjacent primary substation under the configuration.

The expected change in capacity headroom at each of the primary substations is calculated from the peak loads at each substation for each reconfiguration case in comparison to the base case. For the adjacent primary substation, the peak load also provides an indication of whether the configuration in likely to be infeasible as a result of exceeding the firm capacity of the substation.

An outline assessment of the feasibility of each reconfiguration option can be achieved by comparing the peak values of the power flow time series at the boundaries of each transferrable section (and the adjacent substation feeder) with the minimum rating of the main line of the feeder within that section. Where the flow out of a section exceeds that minimum rating, it is likely than an overload exists within the section. Where the flow into a section exceeds the minimum rating, it is possible that an overload exists, depending on the distribution of load and variation of circuit rating within the section.

Configurations which are clearly infeasible through gross overloading of the feeder or adjacent primary substation can be discarded at this stage (unless selective reinforcement of the HV network is to be considered, in which case the degree of overloading will provide guidance on the extent of the reinforcement required). Configurations which show marginal or no overloading should be studied in more detail in the following stage of analysis.

8 Detailed Power Flow Assessment of Transfer Options

The detailed power flow assessment determines the change in primary substation capacity headroom for each configuration, and identifies which, if any configurations are infeasible through thermal or voltage constraint violation. Additional interventions which may be required to support network reconfiguration (such as voltage support or selective reinforcement) are also identified.

8.1 Data Requirements

As before, this analysis stage requires information about the load, and information about the HV network. Ideally, an AC loadflow model of the 11kV network from or within which load is to be transferred would be available, together with loadflow models of those feeders of adjacent 11kV networks onto which transfers are considered potentially feasible as a result of the outline analysis. It is not necessary for adjacent 11kV networks to be modelled in their entirety, except to the extent that the ability to transfer load within them needs to be evaluated. Feeders which are not involved in load transfers may be modelled as ‘lumped loads’.

The minimum scope of the loadflow model should be from the 11kV busbars at the primary substation to the LV busbar at each secondary substation, or to the metering point of HV customers. Where two or more primary substations normally run interconnected at 11kV, or it is desired to study conditions when adjacent 11kV networks are briefly paralleled for load transfer purposes, then the primary substation transformers and upstream higher voltage networks (including lumped loads at other substations) must also be modelled so that consistent conditions at the interconnected primary substations are represented in the model. Dependent on the local network topology, this may involve modelling of small portions of 66kV or 132kV network in addition to 33kV. Otherwise, the 11kV networks may be modelled independently, with a separate slack bus for each maintaining primary busbar voltage to a suitable nominal value.

For reliability estimation, existing and proposed protection devices and remote controlled switches should be included in the model, together with estimaes of their switching time.

Where an AC loadflow model is not available, assessment can proceed using lower fidelity models, such as a DC loadflow model. However, the ability to assess the impact of electrical constraints such as circuit thermal capacity or voltage limits will be reduced or eliminated.

Load data should be extracted from the time series defined in section 6.2 for the following times, as determined by the outline analysis described in section 7:

- The times of peak load at the primary substation from which load is to be transferred, in the normal configuration and following each reconfiguration to be studied.
- The times of peak load on the HV feeder from which load is to be transferred, in the normal configuration and following each reconfiguration to be studied.
- The times of peak load at the primary substations to which load is to be transferred, in the normal configuration and following each reconfiguration to be studied
- The times of peak load on the HV feeder to which load is to be transferred, in the normal configuration and following each reconfiguration to be studied.

The following load data is required:

- For each secondary substation or HV customer which is explicitly represented in the loadflow model, the measured or allocated real and reactive load.
- For each feeder which is modelled as a 'lumped load' in the loadflow model, the real and reactive power flow on that feeder measured at the primary substation.
- For each primary and higher-voltage substation represented as a 'lumped load' in the loadflow model, the real and reactive load at each of the times listed above. If this data is not readily available, the annual peak load (or an estimate) for the relevant year may be extracted from the Long Term Development Statement and used as a 'worst case' value.

In addition, for the reliability analysis described in section 8.4, the following data will be required:

- The number of customers supplied from each secondary substation or HV connection represented in the loadflow model.
- The length of each HV branch in the loadflow model, and its type (i.e. cable or overhead line).
- An estimate of the average reliability (in faults/km/year) and time for fault repair for overhead lines and cables. These should be based on recent statistics for the

DNO, averaged over a sufficient number of years to attenuate the effects of specific adverse weather events.

- An estimate of the switching time for each protective and remote-controlled switch included in the model. Where locally-operated switches are included in the model, estimated switching times may also be used. However, since these switches are unlikely to be operated as part of the load transfer scheme, their inclusion is not strictly required.

8.2 Power Flow Analysis of Load Transfers

Given that a significant number of combinations of network configuration and load measurement time are likely to need to be studied, it is strongly recommended that the analysis process should be scripted within the power system analysis software used.

Initially, power flow studies should be carried out for the ‘base case’ configuration at the times of peak load at each primary substation involved. For each such time, the relevant measured or allocated secondary substation and HV connection load values are extracted from the time series defined in section 6.2 and are applied to the power system model. The power flow solution is then obtained, and the following metrics tabulated for each configuration and measurement instant:

- The load at each primary substation
- The number and severity of thermal constraint violations
- The number and severity of voltage constraint violations

The peak substation loads will be used to determine the change in capacity headroom provided by each possible reconfiguration. Constraint violations observed at this stage may be an indication of deficiencies in the network or load models. These should be investigated to determine whether refinement of either model is required.

For each reconfiguration option found to be feasible or marginally infeasible by the outline assessment, the network model should be configured as required by opening and closing switches (where the software permits this representation) or placing branches in and out of service. Studies should be carried out for the following measurement instants, as determined during the outline assessment:

- The times of peak load at the primary substation from which load is to be transferred, in the base case and following reconfiguration.
- The times of peak load on the HV feeder from which load is to be transferred, in the base case and following reconfiguration.
- The times of peak load at the primary substations to which load is to be transferred, in the base case and following reconfiguration.
- The times of peak load on the HV feeder to which load is to be transferred, in the base case and following reconfiguration.

It will be appreciated that some of these cases may involve the same measurement instant, and that the number of studies required is thereby reduced. For each such instant, the relevant measured or allocated secondary substation and HV connection load values are extracted from the time series defined in section 7.1 and are applied to the power system model. The power flow solution is then obtained, and the following metrics tabulated for each configuration and measurement instant:

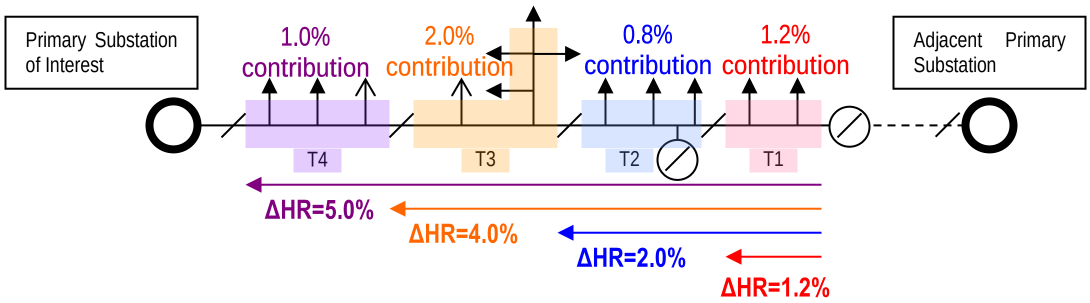
- The load at each primary substation
- The load on each primary substation feeder
- The number and severity of thermal constraint violations
- The number and severity of voltage violations.

Violation of constraints is increasingly likely as the length of HV feeder transferred grows, and will define a maximum extent of transfer for each feeder, beyond which reconfiguration is infeasible. Voltage violations may be reduced or eliminated by installation of voltage regulators, as discussed in [3], and it may be possible to identify small-scale reinforcements to cost-effectively eliminate thermal violations. The effect of such mitigations in permitting larger transfers should be verified by modification of the model and repetition of the loadflow analysis.

For each reconfiguration option which is found to be feasible (or capable of being made feasible through additional interventions), the maximum load over all of the measurement instants analysed is recorded. The change in capacity headroom at the primary substation is then calculated:

$$\Delta HR = \frac{S_{\max,base} - S_{\max,reconfig}}{S_{firm}} \tag{20}$$

where $S_{\max,base}$ is the peak load in the base case, $S_{\max,reconfig}$ is the maximum load following reconfiguration, and S_{firm} is the firm capacity of the primary substation. These values can be added to the table of load transfer steps in Table 1. The contribution of each transferrable section of network to the change in capacity headroom can then be found by comparing the values for adjacent entries in the table, as shown in Figure 8.



Stage	Open Point	Transfer	Headroom	Total Change	Stage Change
0	R5	(base case)	10%	0	–
1	R4	T1	11.2%	1.2%	1.2%
2	R3	T1,T2	12.0%	2.0%	0.8%
3	R2	T1,T2,T3	14.0%	4.0%	2.0%
4	R1	T1,T2,T3,T4	15.0%	5.0%	1.0%

Figure 8: Contribution of transferrable sections to capacity headroom

At this stage, reconfiguration options which give rise to voltage or power flow violations which cannot be remedied should be considered infeasible and removed from further consideration.

8.3 Switching Studies

Reconfiguring the distribution network to achieve the load transfers which have been studied must not involve the interruption of supply to customers. It will thus be necessary to close the existing open point (thereby briefly placing the two primary substations in parallel) before opening a second switch to complete the load transfer. Similarly, to return to a 'normal' configuration when additional capacity headroom is no longer required (or following an unplanned outage with network capacity implications), the new open point must be closed before the normally open switch is reopened.

Under most circumstances, a voltage difference will exist across the open point in the feeder. Where position of the open point or the division of load on the feeder is moved towards one of the substations, this difference will increase, because that part of the circuit is more heavily loaded than normal and thus experiences a larger voltage drop. Thus, it is likely that when a large load transfer is in place (providing a large increase in capacity headroom at one of the primary substations involved), a significant voltage difference may exist across the open point. If large enough, the current flows associated with closing the switch onto this voltage difference could result in unwanted protection operation and loss of supply to customers. Furthermore, during the brief period of parallel operation of the two primary substations during the load transfer, unwanted current flows through the HV network could take place, again with the risk of protection operation.

These unwanted effects can be mitigated through measures such as timing planned load transfer implementation and removal for times of lower load (when the voltage drop along the heavily loaded end of the feeder will be smaller) or by adjusting the voltage at the two primary substations by tapping their primary transformer(s) up or down. The need for, and effectiveness of, these measures should be investigated. It should be noted that inline voltage regulators normally have to be placed in their neutral tap position prior to network reconfiguration to prevent damage from switching transients. A voltage regulator cannot therefore be used to reduce a voltage difference in order to close an open point.

These studies can be undertaken using the loadflow model used for the analysis described in section 8. It is recommended that loads are applied corresponding to the time of peak load at the primary substation from which load is to be transferred, and any voltage regulators set at their neutral tap position. Open points should be configured in turn for each network reconfiguration option along each feeder, and the voltage difference across them tabulated, together with the side of the open point which has the higher voltage. Configurations causing concern in terms of the observed voltage difference should be highlighted for further study as described below.

Where any observed voltage difference gives rise to concern, tapping of the primary transformers at the substations involved should be evaluated. A 3% or 6% reduction at the primary substation on the higher-voltage side of the open point is likely to be most straightforward to apply, and should be simulated for configurations of concern by either reducing the target voltage for the relevant primary transformers (where they are explicitly modelled) or the voltage of the swing bus at the primary busbar.

For planned changes of configuration, adjustment of the primary busbar voltage (affecting all customers supplied from it) can be avoided by switching at times of lower load when voltage differences across open points are smaller. Although this strategy could be examined by applying actual loads from across the year to the model, simply scaling the peak load is likely to give an adequate indication of the level of load which permits switching. For each open point causing concern, the voltage difference should be evaluated while uniformly scaling down the overall system load in steps of 5% to the minimum load shown on the load duration curve mentioned in section 4, and the point at which the voltage becomes acceptable noted. The corresponding level of load can be compared against the load duration curve to determine the overall period in which reconfiguration will be permissible, and against daily load curves to determine times of day when switching should be planned to take place.

8.4 Reliability Assessment

It is likely that network reconfiguration to provide additional capacity headroom will lead to some customers being supplied via a longer HV feeder than at present. This could lead to those customers experiencing more interruptions as a result of faults on the upstream part of the feeder, as shown in Figure 9.

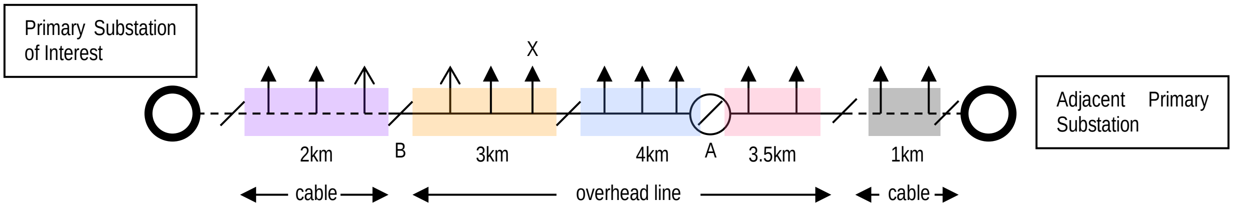


Figure 9: Reconfiguration which may cause change in reliability statistics

In the normal configuration, customers at secondary substation X would experience interruptions as a result of faults in the 2km cable section and the 3km overhead line. Faults in the 4km overhead line would be cleared by the downstream auto-recloser without interrupting customers at X. Following a fault in the cable section these customers could be restored rapidly via A, whereas for a fault in the 3km overhead line section, manual switching or repair would be necessary. If the open point is moved from A to B, these customers are now exposed to interruptions in 1km of cable and 10.5km of overhead line. In the absence of specific understanding about local fault rates, it appears that these customers would experience more interruptions. It will be noted, however, that faults requiring local action to restore these customers are still linked to the 3km overhead line section: the additional interruptions can be restored via B, and are likely to be classified as 'short interruptions'.

To assess the effect on reliability of the various reconfiguration options, it is recommended that power system analysis tool with the capability to calculate reliability metrics should be used. In order to accurately quantify the expected reliability metrics, it would be necessary to use a detailed model of the power system including all protective devices such as sectionalisers and spur fuses, as well as representations of manually-operated switches, including estimates of the time required to operate them. It is unlikely that such a model will be readily available (although if one is available, it should be used).

An estimate of the likely *change* in reliability statistics can however be obtained using a simplified model based on that used for the loadflow studies described in section 8. To this should be added estimates of the average reliability (faults per section per year) and repair time for each cable and overhead line section. These values may be calculated from the length of each section and the average reliability (faults/km/year) for that circuit type.

Such a simplified model will tend to overestimate the number of customer interruptions and average customer minutes lost for the network, since faults on spurs will appear to affect customers supplied from the main line of the feeder, and some opportunities to restore customers by manual switching are not modelled. However, by first using the model to calculate reliability statistics for the base case, the general effect of each reconfiguration on reliability can be assessed by comparing the metrics produced for it by this model with those produced for the base case. At this stage, reconfiguration options with significant adverse consequences for reliability (such as supply of cable-connected customers close to a primary substation via overhead line from a remote primary) may be discarded.

9 Selection of Options for Development

Having conducted the analysis process outlined above, a number of the identified network reconfiguration options are likely to have been discarded, either because of technical infeasibility or adverse effects on reliability.

It is now necessary to identify a subset (which may be the whole set) of the remaining options for further development and implementation. At this stage, engagement with stakeholders from across the DNO, including network operators, planners and those with responsibility for protection and network automation, is important to adequately capture the various interests involved. For each sequence of load transfers along a feeder (as represented by a table similar to that in Figure 8), consideration should be given to whether that feeder should be considered for load transfer, and if so, the extent of the transfer as represented by the number of rows of the table to be implemented.

Factors which should be taken into account in selecting options for development would include:

- The effectiveness of the option in providing additional headroom
- The effect on adjacent primary substations
- The expected cost and implementation time
- The need for additional supporting interventions (such as voltage regulators or protection changes) to permit the option – these will affect the cost and time required.

Additionally, the optimal temporal pattern of transfers should be identified, which should consider both the loading patterns of the primary substations and the expected number of switching operations per year, which will affect switchgear maintenance requirements. A coarser switching pattern (e.g. switching weekly rather than daily) might improve expected maintenance costs at the expense of slightly sub-optimal capacity headroom at the primary substations involved. The period of time over which the additional headroom is needed, and the expected change in primary substation load may also influence this decision – the increase in maintenance cost required may be acceptable to provide headroom over a short period until other interventions can provide additional capacity or reduce load in the long term.

Consideration should also be given at this stage to adding more detailed permanent monitoring to the HV feeders involved. This would provide improved quantification and understanding of network behaviour during load transfer, and will improve quality and reduce risk in the initial design and subsequent review of the Flexible Network Control scheme which is implemented. This could ultimately be expected to lead to better exploitation of available capacity headroom, since margins of uncertainty in network behaviour would be able to be reduced. In the long term, this need will be largely or completely met by next-generation telecontrol equipment. However, where temporary monitoring has been installed to support Flexible Network Control scheme development (as discussed in section 3.1), consideration may be given to leaving it in place for a limited period to monitor initial scheme performance.

10 Application Guide

This section discusses methods by which the network reconfiguration options can be put into practice in the form of a Flexible Network Control scheme. Although one particular method involving, at least initially, Control Engineer led implementation has been selected for use by the Flexible Networks project, this application guide also attempts to provide information and guidance on other approaches which could be adopted.

10.1 Selection of Implementation Approach

In principle, a Flexible Network Control scheme of the sort described here could be implemented either through network automation, or by Control Room intervention. In the first case, algorithms would detect the conditions requiring load transfer, select the load transfer to be applied, initiate switching actions to make the transfer, and reverse the process when network conditions are such that the normal network configuration can be resumed. In a Control Room led approach, these decisions are taken and implemented by Control Engineers in accordance with documented policies and procedures and with some degree of automated support, which may be in the form of Distribution Management System alarms, or pre-defined or pre-configured sequences of switching actions.

Where the number of expected switching actions is low, and where a degree of judgement and experience is required, application and removal of such load transfers by Control Engineer action, supported by automation is recommended as preferable. This situation is likely to arise in particular for seasonal transfers in which it is important to minimise switch operations for maintenance reasons. The point at which the network configuration is returned to normal should be carefully considered so that a reapplication of the transfer will not be required if the load rises unexpectedly.

Where switching is likely to take place frequently, for example in a daily transfer scheme, initiation of reconfiguration by network automation is likely to be preferable in order to avoid placing a significant new workload onto the Control Engineers responsible for the network. However, it will still be necessary to carefully consider the thresholds and deadbands used to configure the scheme in order that the network is not repeatedly switched as the load fluctuates over a short period.

Even if the reconfiguration process is largely or fully automated, it is still important that the Distribution Management System provides complete information about the configuration of the network and the state of the automation scheme. This will enable the

Control Engineer to understand the current state of the network, and its expected response to changes in load, or unexpected events such as fault outages.

A further consideration is whether the implementation should be pro-active or reactive. Consider the HV network shown in Figure 10:

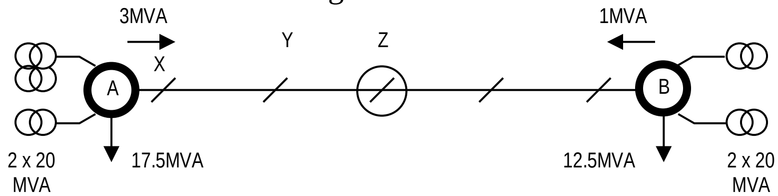


Figure 10: Example reconfiguration case

In the situation shown, the firm capacity at substation A has been exceeded: the total load is 20.5MVA, while the firm capacity is 20MVA. A pro-active reconfiguration scheme would therefore immediately transfer load onto substation B by moving the open point from switch Z to switch Y or switch X. The resulting network configuration would be able to tolerate loss of a transformer at A without exceeding the rated capacity of the remaining transformer.

It can be noted, though, that under intact system conditions, no item of plant is overloaded. Transformer faults are rare, and even following such a fault, the remaining transformer would probably be able to tolerate the modest overload for a period under a dynamic thermal rating regime. In the case of an upstream EHV feeder fault, this period could include waiting for the outcome of an auto-reclose attempt. A reactive reconfiguration scheme would therefore prepare the same switching plan as the pro-active scheme, but would not implement it until an indication of a loss of one transformer was received, and that this loss was permanent. This approach requires that the remaining transformer and any upstream EHV feeder can be given short-term ratings sufficient to supply the complete substation load for the time needed for post-fault switching.

A reactive scheme reduces some of the costs of a pro-active scheme, including switch maintenance and the costs resulting from operation in a sub-optimal configuration for reliability indices. These costs are only incurred in the event of an actual loss of infeed capacity to the substation. Conversely, a reactive scheme would probably have to be automatically initiated so that post-fault actions are taken rapidly. It would need to be closely integrated to the Distribution Management System, so that the initiating conditions can be reliably identified, and to ensure that the Control Engineer's is kept aware of the scheme's intended response to a fault.

10.2 Control Engineer Led Schemes

A Control Engineer led scheme would largely be implemented through the establishment of appropriate Control Room policies and procedures. These policies would be supported by limited Distribution Management System facilities aimed at identifying a potential requirement for action, and carrying out the required sequences of switching actions.

Depending on the arrangements in force in any particular DNO, it may be desirable to produce an outline policy governing the general implementation of Flexible Network Control schemes, together with individual policies which provide supporting detail for each individual scheme. Alternatively, stand-alone policies for each scheme may be preferred.

10.2.1 Requirements for Policy

It is suggested that scheme policies should be determined in advance, but that these should be periodically revised – for example annually, ahead of the peak load season – to reflect forecast network conditions which will affect the amount and duration of load transfer likely to be required. This is discussed in more detail below.

The policies should specify the conditions under which the load transfer will be initiated. This may be strictly time-based, in that the transfer is implemented on a fixed date, or may be load-based, so that it is implemented when the measured load passes a specified value. Conditions for removal of the load transfer should also be set out. Again, these may be purely time-based, or may be triggered by specific load conditions, as discussed in more detail below. The policy may allow the load transfer to be temporarily removed for a period (such as the Christmas holiday), and then re-imposed in response to a triggering event. In general, the policy should specify a single transfer for each feeder which will provide sufficient capacity headroom until removed, rather than incremental transfers along a feeder over time. This will minimise Control Engineer workload and switch maintenance requirements. Incremental transfers involving *different* feeders could still be planned.

The policy should specify the actions to be taken in order to impose or remove the load transfer once the initiating conditions have been detected. Typically this would include checking that:

- All required control facilities are available
- No outages, maintenance activity or other restrictions prevent the load transfer
- The voltage difference across the open point to be closed is not unacceptably high. Where an in-line voltage regulator is providing voltage support, it may be necessary to use a 'ready reckoner' or load flow model to estimate the open point voltage at neutral tap. This is preferable to disturbing customers by tapping to neutral to check the voltage.

Where the transfer is prevented by a large open point voltage difference, the policy should specify actions to reduce this difference to an acceptable level. This may involve adjusting primary transformer AVR set points, or re-scheduling the load transfer for a time when load is lower. The policy should provide guidance on the required level of load with reference to the currently observed load and voltage difference. Recent daily load profiles should then be consulted to determine a suitable switching time.

The policy should give the specific sequence of actions to be undertaken in order to parallel the two primary substations involved in the transfer. This should include the checking and adjustment of primary transformer AVR settings; taking manual control of any in-line voltage regulator, tapping to neutral and verification; any required adjustment to protection settings for parallel operation; and finally closing the paralleling switch. These actions may be made individually by the Control Engineer, or some or all of them may be automated by the DMS. The successful making of the parallel should be verified, and fallback actions specified by the policy in case of failure.

Once the parallel has successfully been made, the two primary substations should be separated, and the HV networks configured for operation in the new state. This will involve opening the required switch to effect the load transfer, and verifying its operation; checking that circuit flows are as expected and that no immediate overloads exist; any required adjustment to protection settings for radial operation with the new open point; re-enabling automatic control of any in-line voltage regulator; adjustment, if required, of primary transformer AVR settings; and finally checking that network currents and voltages are acceptable. These steps may be performed individually, or automated to varying degrees by the DMS. As before, the policy should specify fallback actions in the case of failure.

Operation under unusual network conditions, such as planned or unplanned outages is likely to fall within the scope of existing operational policies. The policy should state which conditions fall into this category. Where these conditions are relatively short-lived, then it is unlikely that adding extra complexity to 'Flexible Network Control' policies will be justified by improved operation of the network. For longer-lived situations – such as a failure of a transformer at a headroom-constrained primary substation such that replacement is needed – it is likely that case-specific planning will be needed. A correctly prepared 'Flexible Network Control' policy may, however, provide valuable support.

The policy should also state what actions should be taken in the event that such unusual conditions arise when the scheme is in operation and transfers have been made. This may include a return to normal network configuration, or a reduction in the extent of one or more transfers, potentially followed by additional transfers to provide additional capacity headroom at the substation of interest.

10.2.2 Policy and Scheme Definition and Maintenance

It is recommended that the policies which implement the Flexible Network Control scheme should be reviewed, and if necessary revised, annually. The review should be based on an assessment of historic scheme performance, and on a forecast of load for the relevant substations for the coming year. The results of the assessment exercise discussed in sections 2 to 9 should be reviewed with respect to any changes in network capability (e.g. new remote-controlled switchgear) or load behaviour. The initial definition of these policies should be based on a similar review of historic and forecast load behaviour. This process of policy definition and maintenance should itself be formalised as a policy.

Factors which should be considered and defined within the scheme policy should include:

- The feeders which are to be subject to load transfer
- The extent of the transfer which is to take place, bearing in mind that, to minimise Control Engineer workload and switchgear maintenance, only one transfer should be specified for each feeder. These first two factors should be selected such that, after taking any enhanced ratings into account, there is an acceptably high probability that load in the period planned-for can be supported within firm network capacity.
- For each load transfer:
    - The order in which it should take place with respect to other transfers in the same scheme. This should be based on factors such as the expected cost in increased CI/CML metrics, and the switching costs of achieving the required level of capacity headroom,
    - The conditions under which it is to occur, which may be either on a particular date; or when a specified load (which corresponds to a particular value of capacity headroom) is observed, either briefly or for a specified sustained period.
    - The conditions under which the transfer should be removed. It is likely that this will be based on load behaviour alone (e.g. that the daily peak load has been continuously below a specified level for a particular number of days), possibly with a time restriction such that the transfer cannot be removed before a particular date. These load values and dates should be selected with reference to historical load profiles and forecast load levels so that the transfer is unlikely to need to be applied more often than intended – for example, in a seasonal scheme, once removed the transfer does not need to take place again before the next peak season.
    - The sequence of actions, including measurement checks and switching operations, required to implement and remove the transfer.
    - Fallback actions required in the case that any stage in the implementation or removal of a transfer fails. These actions may include reversing previously taken steps followed by implementation of a transfer at an alternative location on the feeder and/or on an adjacent feeder; tolerating increase transformer or circuit loads through enhanced thermal ratings (where the feasibility has been assessed); or taking steps to manage load to acceptable levels.
    - Changes to protection settings which are required for paralleled and reconfigured operation.
- Unusual operating conditions which constrain the application of the scheme. These might include:
    - Outages affecting either end of a feeder involved in a transfer, so that the parallel with the remote substation cannot be made.
    - Outages or inward load transfers affecting substations onto which load might be transferred, so that the available capacity headroom is reduced.

In each case, the consequence of the limitation, whether complete infeasibility of the transfer, or a reduction in the extent of the transfer, should be determined.

- Actions to be taken in the event of unusual or unplanned events, including those affecting network capacity at any of the primary substations involved (for example transformer faults, or circuit faults which require customers to be restored by backfeeding).

In addition, the review should produce or review additional supporting material to support Control Engineers in their implementation of the Flexible Network Control scheme. Such material might include:

- Simple loadflow models of the feeder(s) involved in the scheme
- Simple look-up tables or 'ready reckoners' relating open point voltage differences to primary substation loads. Where in-line voltage regulators exist, these should allow the prediction of 'neutral tap' voltages from observations at different possible tap positions.
- Guidance on times when the voltage difference across open points is likely to permit paralleling based on observations of load at specific times of day.

The review process should specifically address the long-term adequacy of each Flexible Network Control scheme, so that the need for future network reinforcement can be anticipated, and reinforcements developed and implemented before additional capacity headroom from Flexible Network Control is exhausted, or the costs of the scheme in switching or reliability become excessive.

Policies setting out the scheme definition and review process should require that appropriate alarms are configured in the Distribution Management System to alert Control Engineers when conditions exist for implementation any of the transfers included in the Flexible Network Control scheme, and are checked or updated as necessary. Where possible, the switching sequences required by the scheme should be configured as a set of automated scripts within the DMS; review and updating of these should be requried as part of the policy review process.

10.3 Automation-Led Schemes

The design and configuration of automation-led schemes should be governed by clearly set out policies. These policies should set out the circumstances in which automation-led control schemes should be considered in preference to Control Engineer led schemes. It is likely that these will include cases in which the preferred reconfiguration involves frequent load transfers, which may be in response to observed power network conditions. Weekly or daily transfers may fall into this category.

As previously discussed, automation-led schemes may be pro-active or reactive in making load transfers. Reactive schemes incur no cost in terms of switching or reliability of supply to customer until *actual* (rather than firm) network capacity is breached, but lead to more network activity immediately after a fault or other contingency. It is recommended that, for consistency, consideration should be given at policy level to whether a mix of pro-active and reactive schemes is acceptable, or whether a uniform preference for one type or the other should be laid down.

The initial stages of designing and implementing an automation-led scheme, and particularly a pro-active scheme are similar to those for a Control Engineer led scheme, in that it will be necessary to identify:

1. The feeders on which load may be transferred
2. The maximum extent of the load transfer on each feeder. It should be noted that multiple stages of load transfer along a feeder may be configured, depending on the forecast requirement for additional capacity headroom.
3. The cost of each transfer, in terms of additional CI/CML and additional switching, in relation to the capacity benefit obtained.
4. The cost of alternative interventions – for example increased exploitation of dynamic ratings – should also be evaluated.
5. The order in which the identified load transfers (and where available, other interventions) are applied may be decided statically at the scheme design and review stage, or it may be decided dynamically by the automation scheme in order to select the lowest cost set of actions to provide the required capacity. If the order is to be dynamically determined, supporting information should be pre-computed:
    a. The CI and CML cost of each transfer
    b. The switching cost of each transfer

   Transfers which are mutually exclusive (e.g. transfers of different lengths of the same feeder) should be identified.
6. The conditions under which the scheme will make load transfers. This may be upon breach of the firm capacity of the substation from which load is to be transferred, or may be at a slightly lower load, to ensure that firm capacity is not breached while the scheme is planning and making load transfers.
7. Required adjustments to protection settings for paralleled and reconfigured operation in making each potential transfer.
8. Conditions under which some or all load transfers cannot be achieved. These may include feeder outages which restrict the ability to parallel adjacent substations, or load transfers or outages affecting adjacent substations which reduce or eliminate the available capacity headroom.
9. Conditions under which the scheme should be inactive, so that response to firm capacity exhaustion should be managed entirely by the Control Engineer.

It will be necessary to construct a loadflow model of the 11kV feeders involved in the transfers in order for the automation scheme to predict the effect and acceptability of switching and load transfer actions. Thermal models of plant which may be subject to enhanced or dynamic ratings should be constructed to support estimation of the cost of such rating.

As in the Control Engineer led case, the design and parameterisation of the scheme should be reviewed regularly in the light of changes to network capability and load. The long-term adequacy of the scheme to meet anticipated future demand should be specifically considered in order that required reinforcements can be delivered in a timely way.

The specific implementation of pro-active and reactive automation-led Flexible Network Control schemes differs somewhat, and each is discussed individually in the following sections.

10.3.1 Pro-active Schemes

In a pro-active scheme, load transfers are made (and other interventions are made or accounted for[1]) as soon as the load exceeds the triggering threshold, which as discussed above may be at or slightly below the firm capacity of the substation from which load is to be transferred. On satisfaction of this condition, the automation scheme should take the following actions:

1. Forecast the expected maximum load on the substations which may be involved in transfers
2. Determine the maximum required additional beyond-firm capacity which is required before the network is returned to normal configuration. For a daily transfer scheme, this will require that the daily peak is forecast, while for a weekly scheme the required figure is the weekly peak. The required additional capacity may include a margin to cover errors in forecasting.
3. Use these forecasts to determine the expected duration of the transfer.
4. If the transfer order is specified in advance, select interventions in the order listed until the required capacity is achieved. Otherwise, select the minimum cost combination of load transfers and other interventions required to provide this capacity. The cost should include:
    a. Pre-computed CI and CML costs of each transfer for the expected duration
    b. Loss-of-life costs incurred by enhanced or dynamic rating use for the forecast load profile after transfers. These costs should reflect the likelihood of the increased rating actually being used as a result of a contingency which reduces actual network capacity to firm capacity, and may require reference to a thermal model of the relevant assets.
    c. Changes in network losses for the expected load profile on each feeder. These should be assessed using the developed load-flow model, with secondary substation and HV customer load scaled to forecast primary substation loads (unless there is an identified need for special treatment).

[1] An intervention involving the use of an enhanced or dynamic rating does not strictly occur until the current in the affected plant exceeds its "usual" rating, which is likely to happen only when a contingency reduces actual capacity to the firm capacity. Nevertheless, the future use of this extra capacity must be accounted for when determining how much load to transfer between substations.

Transfers which are infeasible because of current network conditions (as identified at item 8 in the scheme design activity in the previous section) should be excluded, and additional interventions selected to achieve the required capacity.

5. Implement the required transfers in sequence by:
   a. Checking that required control and automation facilities are available
   b. Checking that the voltage difference across the normally open point will permit its closure. If necessary, the loadflow model should be used to check that the voltage difference is permissible once any in-line voltage regulator is tapped to neutral.
   c. Determining whether adjustment to primary transformer AVRs is necessary prior to paralleling.
   d. Using the loadflow model to ensure that there will be no immediate violation of thermal or voltage constraints in the new configuration
   e. Disabling automatic control of any in-line voltage regulator, and tapping to neutral
   f. Adjusting primary transformer AVRs as required.
   g. Making any protection adjustments required for paralleled operation.
   h. Closing and checking the existing open point.
   i. Opening and checking the switch at the new open point.
   j. Making any protection adjustments required for operation following the transfer
   k. Returning primary transformer AVR settings to their previous state, if required
   l. Re-enabling automatic control of any in-line voltage regulator.

6. If any check or action is unsuccessful, then the steps already taken should be reversed, and the transfer marked as unavailable. Additional transfers or other interventions should be selected to replace the capacity which it would have provided. An alarm should be raised for the attention of the Control Engineer so that investigation of the problem can take place.

7. Although it is expected that a single application of this algorithm should provide sufficient capacity to meet the load peak of the daily or weekly timescale (as appropriate), it is possible that unexpected load increases will required additional interventions. The triggering threshold should therefore be updated, so that further intervention will be initiated in those circumstances. It should be noted that load transfers will not require the threshold to be updated, since their effect is to reduce the load on the primary substation of interest to a level below the existing threshold.

For each load transfer which is made, the Flexible Network Control scheme should determine the conditions under which it may be removed. Since interventions are dispatched in order of cost, their removal should normally be in the reverse order of their application. Therefore, removal of a transfer should require that the load falls to a level which can be met within firm capacity (as modified by previously dispatched enhanced or dynamic ratings), and is expected to remain at or below that level for the remainder of the daily, weekly or other period addressed by the scheme.

When removal of a load transfer is required, this should be achieved by repeating the steps of items 5 and 6 of the process of making a load transfer given above. When a load transfer or other intervention is removed, the triggering threshold for the scheme should be updated so that a further intervention can be made as the load rises to the next peak. As before, removal of a load transfer will normally leave the threshold unchanged.

It should be appreciated that not all of the load transfers or other interventions applied on detection of triggering thresholds will necessarily be removed before the minimum point of the load cycle. Furthermore, where load follows a gradually rising or falling trend, it may be necessary to increase the extent of a load transfer on a feeder between applications, or while it is applied. Figure 11 shows these situations in relation to a simplified and exaggerated load profile.

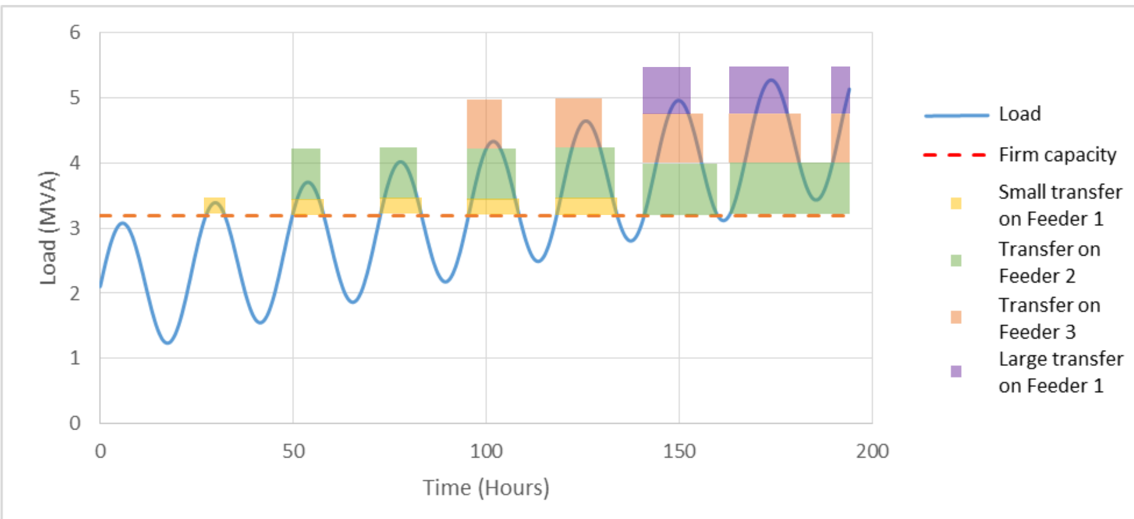


Figure 11: Seasonal load trend results in changes in interventions in pro-active scheme

In Figure 11 (in which perfect forecasting of the load is assumed), the first breach of firm capacity results in the application of the least-cost load transfer, a small reconfiguration of Feeder 1 for a relatively short duration around the peak. On subsequent days, the seasonal load growth (perhaps towards winter peak) means that more transfers are required, such that by the 7th day (i.e. just before 150 hours), the next available transfer is a larger and more costly transfer on Feeder 1, which supersedes the smaller transfer. This means that the transfer on Feeder 2 is now lowest cost. At the end of the following day, the minimum load is such that the transfer on Feeder 2 must remain in effect until the seasonal trend reduces the minimum load below the firm capacity. If the load continued to increase, then the transfer on Feeder 3 would also eventually be retained over the daily minimum.

It is important that Control Engineers are aware of the status and actions of the automation scheme. It is therefore recommended that alarms should be set slightly below the triggering level for initiating load transfers, and slightly above the level for removing a transfer. The scheme itself should update these as the triggering load levels change in response to load transfers. In this way, the Control Engineer will be informed that switching is likely to take place in the near future. Further alarms should be generated on initiation of switching, which should succinctly indicate the transfer(s) which are being made, and when switching is complete. As already mentioned, an alarm should be generated in the event of a failure to complete any element of the scheme, so that investigation and rectification of the problem can be initiated.

At all times, the automation scheme should monitor the level of load on the primary substation from which load is to be transferred, so that intervention is invoked when required. Loads on adjacent primary substations should also be monitored while the load transfer is in place, and DMS alarms generated if firm capacity is exceeded. The Control Engineer can then plan and initiate mitigating action.

Control Room policies should set out methods of enabling and disabling operation of the Flexible Network Control scheme, and circumstances in which this might be necessary. It is recommended that the DMS diagram should indicate the status of the scheme and present controls to enable and disable it. In general, disabling the scheme should prevent any further control actions from being undertaken by it, so that the network remains in the same state until action is initiated by the Control Engineer. It is likely to be preferable to enable the scheme at times of low load, so that no immediate action will be planned and implemented by it. However, if it must be made active at a time of year when load is permanently above the firm capacity of the substation of interest, it may be necessary to enable it with a transfer already having been made. This should be considered carefully in the specific context of any proposed scheme to which it might apply.

10.3.2 Reactive Schemes

In a reactive Flexible Network Control scheme, no switching will take place until a contingency occurs which causes actual network capacity to be less than the measured load. This would typically be the case following the loss of a primary transformer or EHV infeed when the load is above the firm capacity.

The reactive scheme will however, prepare a load transfer plan (incorporating other interventions where appropriate) so that load is rapidly reduced below the actual capacity when the contingency is detected. A result of this approach is that load will be above the network capacity for the period between the contingency and the automated implementation of the transfer plan. It is therefore vital to confirm that short-term dynamic rating capability is available to cover the expected implementation time, as discussed further below.

Since a reactive scheme will only carry out switching in the rare event of a contingency which reduces actual capacity to firm capacity, the average switching and CI/CML costs will be very much lower than a pro-active scheme. However, since load transfers will only take place when they are immediately required to relieve an overload, the risks relating to unreliability are larger, since a rapid response to a failure of the scheme to transfer sufficient load will be needed.

The reactive scheme will normally be in a quiescent state, but should enter a planning mode whenever the measured load exceeds the firm capacity of the substation of interest. The scheme will determine (but not implement the sequence of actions which would be taken if a relevant contingency were to occur at that moment. The actions required in this planning process should be to:

1. Forecast the expected maximum load on the substations which may be involved in transfers
2. Determine the maximum required additional beyond-firm capacity which would be required before the network returned to normal configuration. For a daily transfer scheme, this will require that the daily peak is forecast, while for a weekly scheme the required figure is the weekly peak. The required additional capacity may include a margin to cover errors in forecasting.
3. Use these forecasts to determine the expected duration of the transfer.
4. If the transfer order is specified in advance, select interventions in the order listed until the required capacity is achieved. Otherwise, select the minimum cost combination of load transfers and other interventions required to provide this capacity. The cost should include:
    a. Pre-computed CI and CML costs of each transfer for the expected duration
    b. Loss-of-life costs incurred by enhanced or dynamic rating use for the forecast load profile after transfers. These costs should reflect the likelihood of the increased rating actually being used as a result of a contingency which reduces actual network capacity to firm capacity, and may require reference to a thermal model of the relevant assets.
    c. Changes in network losses for the expected load profile on each feeder. These should be assessed using the developed load-flow model, with secondary substation and HV customer load scaled to forecast primary substation loads (unless there is an identified need for special treatment).

    Transfers which are infeasible because of current network conditions (as identified at item 8 in the scheme design activity in the section 10.3) should be excluded, and additional interventions selected to achieve the required capacity.
5. Generate a switching sequence of required actions to sequentially implement the planned transfers, including:
    a. Checking pre-conditions
    b. Adjustments to protection before and after reconfiguration
    c. Control of primary transformer AVRs and in-line voltage regulators
    d. Switch operations
    e. Checking for success and planning of fallback actions to achieve required load reduction

Where possible, a DMS automation script or a similar facility should be assembled from prepared fragments so that the actions can be rapidly invoked when needed.

This procedure should be repeated frequently and regularly while the measured load is above firm capacity. Planned actions will thereby be based on the most up-to-date forecasts of load behaviour based on current measurements.

When the measured load is above the firm capacity, the scheme will be alert for indications of a relevant contingency, either by monitoring the DMS alarm stream or by detecting sudden upward changes in primary transformer load. When such a contingency is detected, the scheme will enter an active state, and the planned switching sequence will be immediately implemented. Where the contingency can be determined to relate to an item of plant which is subject to transient faults (such as an EHV overhead line), and sufficient short-term overload capacity is available, the scheme may delay action for auto-reclose time. This will avoid unnecessary switching in the case that full capacity is rapidly restored.

If the measured load falls below firm capacity without implementation of the transfer plan, the scheme should return to its normal quiescent state,

Once a transfer plan has been implemented, the scheme should behave in the same way as a pro-active scheme (section 10.3.1), making and removing load transfers as required to support the daily or weekly load pattern.

An exception exists to the rule that a reactive scheme will not act until a contingency is detected. This arises in the case that the measured load is large enough that available short-term capacity cannot support it for the expected switching time. In this case, one or more pro-active load transfers must be made whenever the load exceeds this level so that the load is reduced to a value within the short-term capacity. These transfers should be managed in the same way as for pro-active transfers described in section 10.3.1.

A reactive scheme is likely to result in an HV distribution network which responds more vigorously to faults than is traditional. For this reason, it is important that Control Engineers are informed of the state of the scheme, and are able to interrogate it to determine its planned actions in the event of a relevant fault. DMS alarms should be generated when the scheme enters or leaves its planning mode, and when a plan is revised in response to new measurements of load. The DMS diagram should give an indication of the scheme state, and allow the current plan in case of a contingency to be displayed. As in the case of the pro-active scheme, policies should be established for the enabling and disabling of the scheme by control engineers.

11 References

[1] "Flexible Networks – Improved Use of Primary Substation Data", TNEI report 7640-05.
[2] "Future Roadmap for Improvement of HV & LV Network Modelling ", TNEI report 7640-08.
[3] "Flexible Networks – St Andrews Series Voltage Regulator Location Study", TNEI report 7640-01