THE UNIVERSITY OF TASMANIA

AN EXPERT SYSTEM FOR VOLTAGE CONTROL AND REACTIVE POWER COMPENSATION PLANNING IN THE HEC SYSTEM

BY

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ABTRACT

An Expert System for Voltage Control and Reactive Power Compensation Planning in the H.E.C system

The paper describes an application of an Expert system to the control of voltages and to the evaluation of optimum levels of reactive power compensation in electric power systems.

The expert system is designed to assist in Hydro Electric Commission (HEC) transmission planning studies. Load flow studies of the future configuration of the power system often indicates problems with low voltage levels. To alleviate such problems a decision is required on the choice of control actions which could include the adjustment of machine terminal voltages, or of tap changers on transformers, or the switching of shunt capacitors.

The network sensitivity analysis is utilised to select the most effective control action. The results include specification of the optimal location for shunt capacitors and recommend a size of capacitor bank. The expert system also evaluates the security level for different contingency outages to select the most severe contingency case for the voltage and reactive power control study. The criteria used is based on reactive power reserve margin.

The expert system was developed on the basis of a commercial package VP-EXPERT. The concept of the system utilises the sensitivity tree method to formulate the problem and assist in decision-making. VP-EXPERT interacts with PSSE (Power System Simulator Engineering) which is a power flow software package used by the HEC in load flow analysis. PSSE is provided with an internal data manipulation language IPLAN which allows the creation and analysis of a network sensitivity matrix and the construction of a knowledge base.

The expert system has been successfully tested against the AEP 14-bus network and the North-East Tasmania subsystem. Results of these tests are discussed.

AN EXPERT SYSTEM FOR VOLTAGE CONTROL AND REACTIVE POWER COMPENSATION PLANNING IN THE HEC SYSTEM

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1.INTRODUCTION

In power systems, any changes to the system configuration or in power demands result in voltage variations in the system. These variations may lead to a critical situation being voltage violation or collapse which occurs when the system is unable to meet a given load demand. The situation can be improved by the suitable allocation of reactive power sources throughout the system, i.e., by adjusting transformer taps, changing generator voltages, and by switching reactive power compensation (VAR). Control of reactive power sources in the system will improve the voltage profile and can reduce the system losses. An optimization procedure for the direct computation of voltage and reactive power control is implemented on the basis of the network sensitivity analysis [7,8,16,17,18].

In the planning and design of a high voltage transmission network, it is desirable to install controllable VAR capacity to support voltages at load buses during emergencies. The selection of where and how much VAR capacity is required to maintain satisfactory voltage levels to overcome the voltage violation problem during critical contigencies is presented [12,13,14].

A methodology to determine the voltage stability limit of a multi-machine power system is introduced. This method is used to determine the critical system state for the voltage and reactive power control study [10,11].

In the past, many methods of VAR control have been developed to minimize the system losses and to improve the voltage profiles. They employ different optimization techniques. These methods are complex, and they only provide analytical solutions but do not provide direct advice to the system operators on the actions required to overcome the problem.

Expert systems (Artificial Intelligence) have attracted much interest in recent years. Application of expert systems to power systems is still in its initial development stage, and much research has been undertaken to bring this new technique into practical use [1,2,3,4,23].

The main objective of this thesis is to develop an expert system for reactive power compensation. It is designed to improve the security of power system and to reduce system losses. In particular, it is designed to convert analytical solutions into a sequence of actions to be performed by operators or system designers.

The proposed objective of the expert system is to aid in the detection of voltage violation problems and in the search for a control scheme to correct any detected voltage problem. The expert system will be designed to assist transmission planning engineers to formulate a strategy for the reactive power compensation of the system. It will include a concept of reactive power reserve to be available in the system to cover major transmission/generation plant outages, and the selection of locations and minimum VAR capacity that should be installed to improve system security and to reduce system losses.

2. THEORY ON VOLTAGE CONTROL AND REACTIVE POWER COMPENSATION

In steady state, the power system behavior can be described by the power flow relations. Given the power system topology, component parameters, power generations and load demands, the power equations can be solved to obtain bus voltages and angles. When an operating point is close to the nominal condition, the power flow relations can be approximated by decoupled equations. That is:

- The real power injections (generations and loads) are more sensitive to variation in voltage angles, and

- The reactive power injections are more sensitive to variation in voltage magnitudes.

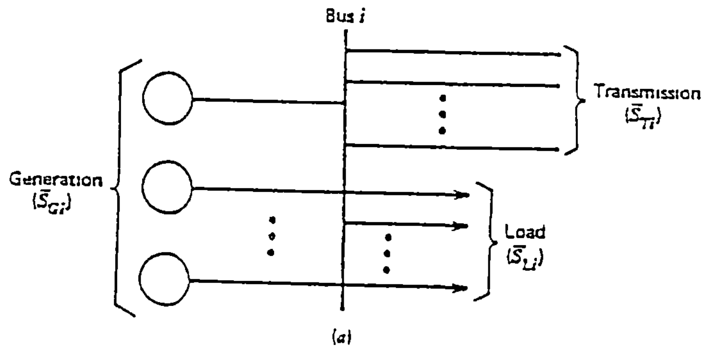
When reactive power is injected into a load bus, the voltage at the bus increases. Based on the decoupling property, bus voltage magnitudes can be maintained by controlling the reactive power injections into the power system.

To ensure the quality and reliability of supply to the customers by maintaining the load bus voltages within certain upper and lower limits is a practical requirements in power system operation. Any changes to the system configuration or in power demands can result in higher or lower voltages in the system. Abnormal voltages may lead to equipment damage, or the equipment may be switched out of the system if it is protected by automatic devices.

2.1. POWER SYSTEM MODEL

In general an electrical power system can be represented by Figure 2.1.1.

Thinking of the system as being modelled by an electrical network, it would see that the straightforward approach would be to use either conventional-loop or nodal-analysis methods to solve for voltages and currents of interest. This direct approach is not possible, because the loads are known as complex powers, not impedances; also, the generators can not be modelled as voltage sources in the circuit analysis sense but behave more like power sources. This problem is basically that of solving 2N non-linear algebraic equations for a N bus system and therefore requires numerical analysis techniques.



where

$\bar{S}_{Gi}$ = 3ϕ complex generated power flowing *into* the i^{th} bus.
$\bar{S}_{Li}$ = 3ϕ complex load power flowing *out of* the i^{th} bus.
$\bar{S}_{Ti}$ = 3ϕ complex transmitted power flowing *out of* the i^{th} bus.

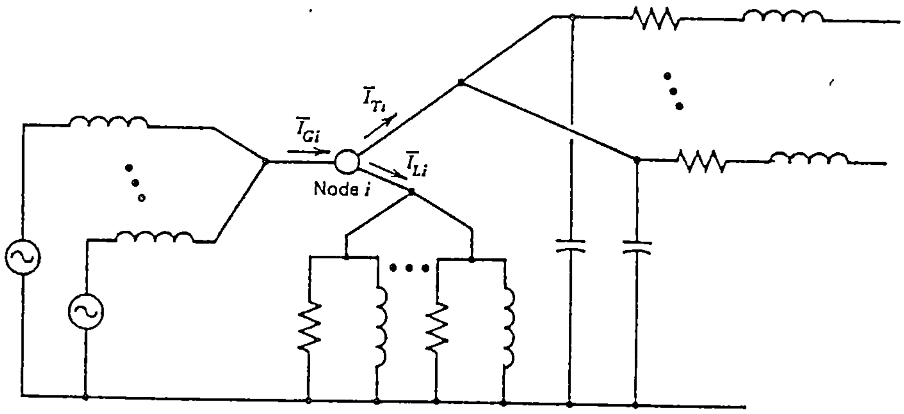


Figure 2.1.1 Representation of an electrical power system.

By considering

$$\bar{I}_{Gi} = \bar{I}_{Li} + \bar{I}_{Ti} \quad (2.1.1)$$

Taking the conjugate,

$$\bar{I}^*_{Gi} = \bar{I}^*_{Li} + \bar{I}^*_{Ti}$$

Multiplying through by $\bar{V}_i$,

$$\bar{V}_i \bar{I}^*_{Gi} = \bar{V}_i \bar{I}^*_{Li} + \bar{V}_i \bar{I}^*_{Ti}$$

$$\bar{S}_{Gi} = \bar{S}_{Li} + \bar{S}_{Ti} \quad (2.1.2)$$

Since

$$\bar{S}_{Gi} = P_{Gi} + j\,Q_{Gi} \quad (2.1.3)$$

$$\bar{S}_{Li} = P_{Li} + j\,Q_{Li} \quad (2.1.4)$$

$$\bar{S}_{Ti} = P_{Ti} + j\,Q_{Ti} \quad (2.1.5)$$

It follows that

$$P_{Gi} = P_{Li} + P_{Ti} \quad (2.1.6)$$

$$Q_{Gi} = Q_{Li} + Q_{Ti} \quad (2.1.7)$$

The P's and Q's represent real and reactive powers, respectively. They total to six variables per bus. For a N bus system, we have 2N equations involving 6N variables. Power flow calculations are made at specified load conditions. Therefore, P_{Li} and Q_{Li} are given. This leaves us with four variables per bus: P_{Gi}, Q_{Gi}, P_{Ti} and Q_{Ti}, so we shall investigate its structure and detail.

2.1.1. STATEMENT OF THE POWER FLOW PROBLEM

By recalling the complex transmitted power in equation (2.1.5).

$$\bar{S}_{Ti} = P_{Ti} + j\,Q_{Ti} = \bar{V}_i \bar{I}_{Ti}^*$$

We now may eliminate the current $\bar{I}_{Ti}^*$ using the admittance matrix [Y].

Recall $[I] = [Y]\ [V]$

Or $\bar{I}_{Ti} = \sum_{j=1}^{N} \bar{y}_{ij} \bar{V}_j \qquad i = 1, 2,...,N$

Let $\bar{y}_{ij} = y_{ij} \angle \gamma_{ij}$

$\bar{V}_j = V_j \angle \theta_j$

Then $\bar{I}_{Ti}^* = \sum_{j=1}^{N} y_{ij} V_j \angle - \theta_j - \gamma_{ij}$

Thus $\bar{S}_{Ti} = \sum_{j=1}^{N} V_i V_j y_{ij} \angle \theta_i - \theta_j - \gamma_{ij} \qquad i = 1, 2,..., N$

In rectangular components,

$$P_{Ti} = \sum_{j=1}^{N} V_i V_j y_{ij} \text{ COS } (\theta_i - \theta_j - \gamma_{ij}) \qquad (2.1.8)$$

$$Q_{Ti} = \sum_{j=1}^{N} V_i V_j y_{ij} \text{ SIN } (\theta_i - \theta_j - \gamma_{ij}) \qquad (2.1.9)$$

$i = 1, 2,...,N$

We have replaced the 2N variables (P_{Ti} and Q_{Ti}) by the 2N variables (V_i and θ_i).

It shows that the transmitted real and reactive powers at a given bus will in general be a function of the voltage magnitude and phase at all the other buses in the system.

By substituting P_{Ti} and Q_{Ti} in equations (2.1.6) and (2.1.7), we have:

$$P_{Gi} = P_{Li} + \sum_{j=1}^{N} V_i V_j y_{ij} \cos(\theta_i - \theta_j - \gamma_{ij}) \tag{2.1.10}$$

$$Q_{Gi} = Q_{Li} + \sum_{j=1}^{N} V_i V_j y_{ij} \sin(\theta_i - \theta_j - \gamma_{ij}) \tag{2.1.11}$$

$$i = 1, 2, \ldots, N$$

The admittance $\bar{y}_{ij}$ in rectangular form is

$$\bar{y}_{ij} = G_{ij} + j B_{ij} \tag{2.1.12}$$

Where G_{ij} is the conductance between node i and j,

B_{ij} is the susceptance between node i and j.

Let $C_i = P_{Li}$

$D_i = Q_{Li}$

$P_i = P_{Gi}$

$Q_i = Q_{Gi}$

The equations (2.1.10) and (2.1.11) can be rewritten as:

$$P_i = C_i + V_i \sum_{j=1}^{N} V_j \left[G_{ij} \cos(\theta_i - \theta_j) + B_{ij} \sin(\theta_i - \theta_j) \right] \tag{2.1.13}$$

$$Q_i = D_i + V_i \sum_{j=1}^{N} V_j \left[G_{ij} \sin(\theta_i - \theta_j) - B_{ij} \cos(\theta_i - \theta_j) \right] \tag{2.1.14}$$

Hence, the power flow of the general N bus power system is described by a set of 2N simultaneous equations.

Consider a power system with N buses, or substations. The generator buses are numbered from 1 to N_G and the load buses from N_G+1 to N (ie. $N = N_G + N_L$), where N_L is the number of load buses.

To solve the load flow equation, normally the real power injection and bus voltage magnitude, P_i and V_i , at a generator bus; and the real and reactive power demands, P_i and Q_i , at a load bus, are specified. A slack bus (or swing bus) with constant V_i and θ_i is also designated.

By considering the voltage independent load demands, equations (2.1.13) and (2.1.14) can be solved to obtain the steady state power system operating point.

TABLE 1 : Bus type for power flow analysis

Bus type	Type	Known	unknown
slack	3	V_i , θ_i	P_i , Q_i
generator	2	P_i , V_i	Q_i , θ_i
load	1	P_i , Q_i	V_i , θ_i

2.2 NETWORK SENSITIVITY ANALYSIS

Power system operators ensure the quality and reliability of supply to the customers by maintaining the load bus voltages in their permissible limits. Any changes to the system configuration or in power demands can result in higher or lower voltages in the system. Redistribution of reactive power generations in a power system is necessary to improve the system voltage profiles and to minimize the real power losses. Reactive power distributions in the system can be controlled by the system operator by suitably adjusting the following controllable variables:

- Transformer taps
- Generator terminal voltages
- Switchable shunt capacitors/ reactors (VAR sources)

These control variables (state variables) have their upper and lower permissible limit. Any changer to these state variables have the effects of changing the system voltage profiles and the reactive power output of generators and system losses.

The sensitivity analysis formulates the reactive power allocation problem extending the method of Newton-Raphson (NR) loadflow. In the NR loadflow method, the Jacobian is formed relating real and reactive power injections to changes in bus voltages and angles. The inverse of the Jacobian matrix is called the Sensitivity matrix, which is used to find the most sensitive parameter in the control variables, which when adjusted will produce the most effective change in the dependent variables so that a certain desired operating condition can be achieved.

2.2.1 NETWORK SENSITIVITY MATRIX

The basis loadflow equation (2.1.13) and (2.1.14) can be rewritten as follows:

$$G_{2k-1} = C_k - P_k + V_k \sum_{\alpha}^{N} V_{\alpha k}[G_{k\alpha} \text{COS}(\theta_k - \theta_\alpha) + B_{k\alpha}\text{SIN}(\theta_k - \theta_\alpha)] = 0 \tag{2.2.1}$$

$$G_{2k} = D_k - Q_k + V_k \sum_{\alpha}^{N} V_{\alpha k}[G_{k\alpha} \text{SIN}(\theta_k - \theta_\alpha) - B_{k\alpha}\text{COS}(\theta_k - \theta_\alpha)] = 0 \tag{2.2.2}$$

where

P_k , Q_k : Active and reactive power generation at bus K
C_k , D_k : Active and reactive power consumption at bus K
α : Set of nodes directly connected to node K, including node K itself.

For simplicity, the variables and parameters involve in equations (2.2.1) and (2.2.2) will be classified into three vectors:

(i) Operating variable vector U:

It is also denoted as the independent variable vector or the control vector. This is an M_dimensional vector comprising of the operating variables in system voltage and reactive power control (ie. generator terminal voltages, transformer taps and switchable shunt capacitors/ reactors).

(ii) Controlled and dependent variable vector X:

This vector consists of such unknown variables in usual power flow calculations as voltage magnitudes and phase angles at load nodes, reactive power flows of branches which do not appear explicitly, and such other dependent variables as voltage magnitudes and phase angles not included in the operating variable vector V. The total number of controlled and dependent variable explicit in (2.2.1) and (2.2.2) must equal 2N in order for the power flow to be specified uniquely.

(iii) Parameter vector P:

The components of the parameter vector P are the variables whose values are specified in load flow calculation excluding operating variables, conductances, and susceptances not influenced by the change of tap positions of load ratio controllers.

Therefore, the electrical variables are classified as follows:

$$U = \begin{array}{ll} V, \theta & \text{for the slack bus} \\ P, V & \text{for the generator bus} \\ P, Q & \text{for the load bus} \\ n & \text{(turns ratio) for the inphase controllable transformer} \\ \text{other control variables} & \end{array} \tag{2.2.3}$$

$$X = \begin{array}{ll} P, Q & \text{for the slack bus} \\ Q, \theta & \text{for the generator bus} \\ V, \theta & \text{for the load bus} \end{array} \tag{2.2.4}$$

$$P = \quad C, D \quad \text{for all buses} \tag{2.2.5}$$

By use of these three vectors X, U and P. Equations (2.2.1) and (2.2.2) can be expressed as:

$$G (X, U, P) = 0 \tag{2.2.6}$$

where G is a 2N - dimensional column vector function with G_{2k-1} and G_{2k}, K = 1, 2.... N as its components.

$$G = \text{col} (G_1, G_2 ..., G_{2k-1}, G_{2k},..., G_{2n-1}, G_{2n}) \tag{2.2.7}$$

Suppose that in an N-node power system the operating condition is such that $X = X_0$ for a specified control vector $U = U_0$. Since the pair of vectors X_0 and U_0 satisfies the power flow equation (2.2.6). Then

$$G(X_0, U_0, P) = 0 \tag{2.2.8}$$

Let us assume that by changing the operating condition of voltage and reactive power regulating devices, the operating variable vector U has experienced a change ΔU from U_0. If the control and dependent variable vector X changes from X_0 to $X_0 + \Delta X$ in accordance with the change ΔU, then

$$G(X_0 + \Delta X, U_0 + \Delta U, P) = 0 \tag{2.2.9}$$

If ΔU is taken to be very small, then the variance ΔX is generally small. By applying the Taylor series expansion to (2.2.9) with X_0, U_0, P as the reference state and neglecting higher order terms in ΔX and ΔU, we have:

$$G(X_0, U_0, P) + G_x(X_0, U_0, P)\,\Delta X + G_u(X_0, U_0, P)\,\Delta U = 0 \tag{2.2.10}$$

Where G_x is the Jacobian matrix of G with respect to the controlled and dependent variable vector X.

$$G_x = \frac{\partial (G_1, G_2, \ldots, G_{2N})}{\partial (X_1, X_2, \ldots, X_{2N})} \tag{2.2.11}$$

Where $X_1, X_2 \ldots, X_{2N}$ are the elements of X. In similar manner,

$$G_u = \frac{\partial (G_1, G_2, \ldots, G_{2N})}{\partial (U_1, U_2, \ldots, U_M)} \tag{2.2.12}$$

Where $U_1, U_2 \ldots U_M$ are the elements of the operating variable vector U. Note that, in general, G_u is not a square matrix. Equation (2.2.8) and (2.2.10) gives

$$G_x(X_0, U_0, P)\,\Delta X = -G_u(X_0, U_0, P)\,\Delta U$$

$$\Delta X = -[G_x]^{-1}[G_u]\,\Delta U \tag{2.2.13}$$

Let

$$S = -[G_x]^{-1}[G_u] \tag{2.2.14}$$

Then

$$\Delta X = S\,.\,\Delta U \tag{2.2.15}$$

or more concretely in matrix form

$$\begin{bmatrix} \Delta X_1 \\ \Delta X_2 \\ \cdot \\ \cdot \\ \cdot \\ \Delta X_{2N} \end{bmatrix} = \begin{bmatrix} S_{11} & S_{12} & \ldots\ldots & S_{1M} \\ S_{21} & S_{22} & \ldots\ldots & S_{2M} \\ \cdot & & & \\ \cdot & & & \\ \cdot & & & \\ S_{2N1} & S_{2N2} & \ldots\ldots & S_{2NM} \end{bmatrix} \begin{bmatrix} \Delta U_1 \\ \Delta U_2 \\ \cdot \\ \cdot \\ \cdot \\ \Delta U_M \end{bmatrix}$$

(2.2.16)

The $2N_xM$ coefficient matrix S is called the sensitivity matrix of power flow with respect to the operating variable U. This matrix gives a linear relation between a small change in the operating vector U, and the corresponding change in the controlled and dependent variable vector X. This linear relation is fully utilized in the optimizing computation of real time voltage and reactive power control.

2.2.2 PROGRAMMING TECHNIQUE USEFUL FOR COMPUTATION OF S MATRIX

Recall equation (2.2.13)

$$\Delta X = -[G_x]^{-1} [G_u] \Delta U$$

rewrite

$$[G_x] \Delta X = -[G_u] \Delta U \qquad (2.2.17)$$

or in matrix form.

$$\begin{bmatrix} \frac{\partial G_1}{\partial X_1} & \frac{\partial G_1}{\partial X_2} & \cdots & \frac{\partial G_1}{\partial X_{2N}} \\ \frac{\partial G_2}{\partial X_1} & \frac{\partial G_2}{\partial X_2} & \cdots & \frac{\partial G_2}{\partial X_{2N}} \\ \vdots & \vdots & & \\ \frac{\partial G_{2N}}{\partial X_1} & \frac{\partial G_{2N}}{\partial X_2} & \cdots & \frac{\partial G_{2N}}{\partial X_{2N}} \end{bmatrix} \begin{bmatrix} \Delta X_1 \\ \Delta X_2 \\ \vdots \\ \Delta X_{2N} \end{bmatrix} = - \begin{bmatrix} \frac{\partial G_1}{\partial U_1} & \cdots & \frac{\partial G_1}{\partial U_M} \\ \frac{\partial G_2}{\partial U_1} & \cdots & \frac{\partial G_2}{\partial U_M} \\ \vdots & & \\ \frac{\partial G_{2N}}{\partial U_1} & \cdots & \frac{\partial G_{2N}}{\partial U_M} \end{bmatrix} \begin{bmatrix} \Delta U_1 \\ \Delta U_2 \\ \vdots \\ \Delta U_M \end{bmatrix}$$

(2.2.18)

Let us divide the controlled and dependent variable X into two smaller vectors X_x and X_y. The former stands for reactive powers and voltage magnitudes, and the latter for active powers and phase angles. Furthermore, divide the 2N modal power flow equations G into function vectors:

$$G_{2k} = G_{even} = \mathrm{Col}\,(G_2, G_4, G_6,\ldots, G_{2k}, \ldots G_{2N}) \qquad (2.2.19)$$

Associated with reactive power flows and

$$G_{2k-1} = G_{odd} = \mathrm{Col}\,(G_1, G_3, G_5,\ldots, G_{2k-1}, \ldots G_{2N-1}) \qquad (2.2.20)$$

Related to active power flows. Then the Jacobian matrix G_x is partitioned as

$$G_x = \left[\begin{array}{c|c} \dfrac{\partial G_{even}}{\partial X_x} = A & \dfrac{\partial G_{even}}{\partial X_y} = B \\ \hline \dfrac{\partial G_{odd}}{\partial X_x} = C & \dfrac{\partial G_{odd}}{\partial X_y} = D \end{array}\right] \qquad (2.2.21)$$

Where A, B, C and D are NxN Jacobian matrices. In similar manner, G_u matrix is partitioned as

$$G_u = \left[\begin{array}{c} \dfrac{\partial G_{even}}{\partial U} = I \\ \hline \dfrac{\partial G_{odd}}{\partial U} = J \end{array}\right]$$

Where I and J are NxM matrices. Then equation (2.2.17) can be rewritten as:

$$\left[\begin{array}{c|c} A & B \\ \hline C & D \end{array}\right] \left[\begin{array}{c} \Delta X_x \\ \hline \Delta X_y \end{array}\right] = - \left[\begin{array}{c} I \\ \hline J \end{array}\right] [\Delta U] \qquad (2.2.23)$$

The rank of the Jacobian matrix G_x originally employed for the determination of the sensitivity matrix is equal 2N where N is the total number of nodes, and it might be anticipated that the computing time required for the calculation of the S matrix of a large scale power system would become prohibitively long because the inversion of G_x is involved. In general, the changes in active powers and voltage phase angles caused by the operation of voltage and reactive power regulating devices are very small compared with those in reactive powers and voltage magnitudes. There∂fore, the sensitivity constants for the former close of system variables may be neglected in the practice of voltage and reactive power control. This approach has the advantage of reducing the size of the sensitivity matrix from the size of (2N x 2N) to a size of (N x N). Thereby saving much computation storage and effort without adverse effect on accuracy.

Finally, for voltage and reactive power control we rewrite the sensitivity matrix with $X = X_x$ as follows:

$$\Delta X = - \left[\frac{\partial G_{2k}}{\partial X}\right]^{-1} \frac{\partial G_{2k}}{\partial U} \Delta U \qquad (2.2.24)$$

or

$$S = - [J_x]^{-1} [J_u] \qquad (2.2.25)$$

where

$$J_x = \left[\frac{\partial G_{2k}}{\partial X}\right]$$

$$J_u = \left[\frac{\partial G_{2k}}{\partial U}\right]$$

where ΔX represents the small change in the controlled and dependent variable X in accordance with the change in ΔU. Thus [U], [X] and [P] can be reduced to:

$$U = \begin{cases} V & \text{for the slack and generator bus} \\ Q & \text{for the load bus} \\ n & \text{for the controllable transformer} \\ \text{other controllable variables} & \end{cases}$$

$$X = \begin{cases} Q \text{ for the slack and generator bus} \\ V \text{ for the load bus} \end{cases}$$

$$P = \quad D \text{ for all buses}$$

2.2.3. DERIVATION OF THE SENSITIVITY MATRIX

Recall equation (2.2.25)

$$S = -[J_x]^{-1}[J_u]$$

The devices available for controlling the violated contraints are

(i) Generation buses (PV and slack), whose terminal voltage, V, can be regulated.

(ii) Controllable transformers tap position, n, can be regulated.

(iii) Switchable reactive power sources (capacitor/ reactor, D, can be regulated).

The calculation of the sensitivity matrices for these three control devices is as follows:
(obtained from equation (2.2.2))

a) The elements of the $[J_x]$ matrix

(i) Generator buses $$\frac{\partial G_{2k}}{\partial Q_i} = \begin{cases} -1 & \text{for } i = K \\ 0 & \text{for } i \neq K \end{cases} \qquad (2.2.26)$$

(ii) load buses $\dfrac{\partial G_{2k}}{\partial V_i} =$

$$\begin{cases} \sum_{\alpha}^{N} V_\alpha [G_{i\alpha} \mathrm{SIN}(\theta_i - \theta\alpha) - B_{i\alpha} \mathrm{COS}(\theta_i - \theta\alpha)] - V_i B_{ii} & \text{for } i = K \\ V_k [G_{ki} \mathrm{SIN}(\theta_k - \theta i) - B_{ki} \mathrm{COS}(\theta_k - \theta i)] & \text{for } i = \alpha \ (\neq K) \\ 0 & \text{for } i \neq \alpha \neq K \end{cases}$$

(2.2.27)

b) The elements of the $[J_u]$ matrix

(i) Generators $\dfrac{\partial G_{2k}}{\partial V_i} =$

$$\cdot \sum_{\alpha}^{N} V_\alpha \, [G_{i\alpha} \mathrm{SIN}(\theta_i - \theta\alpha) - B_{i\alpha} \mathrm{COS}(\theta_i - \theta\alpha)] - V_i B_{ii} \qquad \text{for } i = K$$

$$\cdot V_k [G_{ki} \mathrm{SIN}(\theta_k - \theta i) - B_{ki} \mathrm{COS}(\theta_k - \theta i)] \qquad \text{for } i = \alpha \; (\neq K)$$

$$\cdot 0 \qquad \text{for } i \neq \alpha \neq K$$

(2.2.28)

(ii) Reactive power sources (switchable shunt capacitor/ reactor)

$$\frac{\partial G_{2k}}{\partial D_i} = \begin{cases} 1 & \text{for } i = K \\ 0 & \text{for } i \neq K \end{cases}$$

(2.2.29)

(iii) Controllable transformers $\dfrac{\partial G_{2k}}{\partial n} =$

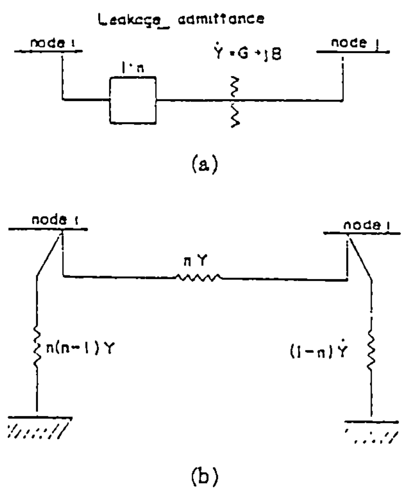
$$\cdot \frac{V_i V_j}{n} [G_{ij} \mathrm{SIN}(\theta_i - \theta_j) - B_{ij} \mathrm{COS}(\theta_i - \theta_j)] + 2 V_i^2 B_{ij} \qquad \text{for } i = K$$

$$\cdot \frac{V_i V_j}{n} [G_{ij} \mathrm{SIN}(\theta_i - \theta_j) + B_{ij} \mathrm{COS}(\theta_i - \theta_j)] \qquad \text{for } j = K$$

$$\cdot 0 \qquad \text{for } i, j \neq K$$

(2.2.30)

Note that $V_i > V_j$



Load ratio controller. (a) Original circuit.
(b) Equivalent circuit.

2.3. VOLTAGE CONTROL AND REACTIVE POWER COMPENSATION

2.3.1. VOLTAGE CONTROL

The control variables have their upper and lower permissible limits. For the transformer taps and generator voltages, and for the switchable shunt VAR sources, these limits can be observed, respectively, by the inequality constraints:

$$n_{ij}^{min} \leq n_{ij} \leq n_{ij}^{max} \quad (2.3.1)$$

$$Q_G^{min} \leq Q_G \leq Q_G^{max} \quad (2.3.2)$$

$$D_i^{min} \leq D_i \leq D_i^{max} \quad (2.3.3)$$

where

n_{ij}^{max}, n_{ij}^{min}, n_{ij}: are the maximum and minimum and the present tap position (in turns ratio) settings of the transformer between bus i and j.

Q_G^{max}, Q_G^{min}, Q_G: are the maximum and minimum limits and the operating value of the reactive power output of the generator at bus G.

D_i^{max}, D_i^{min}, D_i: are the maximum and minimum VAR limits and the present VAR output of the switchable shunt VAR source at bus i.

Voltage control in the power system is subject to security constraints such as thermal limits of equipments, line and generator capacities, etc.

The voltage limits are denoted by a set of inequalities:

$$V_i^{min} \leq V_i \leq V_i^{max} \qquad i = 1, 2 \ldots n \quad (2.3.4)$$

For load buses, the typical voltage limits at normal operation are:

$$V_i^{min} = 0.95 \text{ pu}, \qquad V_i^{max} = 1.05 \text{ pu}$$

The voltages at generator buses, however, are controlled but they are vary in a narrow band typically of 1%.

When the load voltage violates the constraints of equation (2.3.4), normal practice is to utilize reactive compensators such as switched shunt capacitors, reactors, transformer tap changers, synchronous condensers, to restore the voltage profile. The generator bus voltages are also controlled to maintain the load voltages. However, if the utilization of all of the above methods fails to restore the voltage profile, the system operators will have to resort to load management.

The following control measures are commonly used to adjust reactive power and bus voltage of a power system:

(i) Change of the transformer tap:

This measure increases or decreases bus voltage by changing the transformer turns ratio (n). Let the tap position of the transformer at point i before control be denoted by n_{ij}^{o} and assume that it is controlled by Δn from this value. Then the admissible value of operation of the load ratio controller must be an integer satisfying

$$n_{ij}^{min} \leq n_{ij}^{o} + \Delta n \leq n_{ij}^{max} \quad (2.3.5)$$

(ii) Change of the generator terminal voltage:

This measure supplies a certain amount of reactive power to the transmission line and so the voltage drops along the lines are controlled. Changing the injected reactive power by changing the generator excitation alters both generator bus and load bus voltages. This approach is similar for synchronous condenser.

$$Q_G^{min} \leq Q_G^{o} + \Delta Q_G \leq Q_G^{max} \qquad (2.3.6)$$

where

Q_G^{o} is the reference value of the generator reactive power output before control.

ΔQ_G is the operating amount of reactive power adjustment.

(iii) Change of shunt capacitor or shunt reactor:

Increasing the shunt capacitor (reactor) injects (rejects) reactive power on the bus and increases (decreases) bus voltage at all loads. Usually the closer the bus to the shunt capacitor (reactor) electrically, the more the voltage is increased (decreased).

The inequality

$$D_i^{min} \leq D_i^{o} + \Delta D_i \leq D_i^{max} \qquad (2.3.7)$$

should be fulfilled, where D_i^{o}, ΔD_i are the number of shunt capacitors (reactors) switched on or off and the number of banks before control, respectively. All variables must take on integers.

Note that, since buses in a power system are connected via the transmission lines. By changing the control variable settings, some bus voltages increase and other bus voltages decrease. Suppose that one of the control variables is changed to alleviate the violation, and a set of nodes corresponding to the changed control variable represents a number of dependent variables that may also be violated as a result of the change in the control variable. In order to avoid the occurrence of the new violations, pre-checking would have to be considered in the problem formulation.

It is also noted that, when the above control measures are used to control the power system voltage, they are not equally effective. In addition, the amount of control needed from each measure is not unique. For these reasons, some additional criteria are needed in practice, one criterion of interest is used to find the effective order of the control actions is the sensitivity technique which has been described in section 2.2.

2.3.2 REACTIVE POWER COMPENSATION (SHUNT CAPACITOR INSTALLATION)

As the bus voltage is strongly dependent on the reactive power flow, the reactive power dispatch can be used to control the bus voltages. This happens when the use of all the above mentioned control measures is not able to overcome the voltage violation problem.

Actually, reactive power redispatch is more or less equal to the measure of reactive power compensation. This is because reducing the reactive power drawn from a certain bus is the same as increasing the reactive power injection at that bus. The difference is that the reactive power compensation measures are pre-installed. They may not be available on each load bus, whereas, the reactive power dispatch is usually available to some extent.

However, as reactive power requirements on the load buses are mainly decided by the consumer, the reactive power dispatch has to take into account the consumers' requirements. If those requirements cannot be satisfied, it means that additional reactive power compensation measures such as shunt capacitors are needed.

2.3.2.1 AUTOMATIC ALLOCATION OF NETWORK CAPACITORS

Selecting locations and sizes for capacitor banks which are used for voltage correction in a transmission system is a problem that planning engineers have to face very often. Due to the configuration of present transmission networks, it is impossible to predict by simple inspection of the system the amount and location of static capacitors required to raise voltages above certain minimums.

The following section describes a procedure that performs capacitor location and size automatically, by taking a number of low-voltage buses and carrying out a sensitivity measure to define the best bus for shunt capacitor installation. Finally a trial and error analysis is required to calculate the capacitor bank size.

a) Bus selection

Selecting a bus in the system to which a capacitor should be added requires a criterion that will dictate the choice. Since the purpose of adding capacitors is to raise the voltage level, a sound criterion would be to define the best bus as the one that causes the maximum overall voltage rise in all the low-voltage buses when a test capacitor is added.

The analysis of the sensitivity measure is based on the bus impedances frame.

$$\bar{E}_{bus} = \bar{Z}_{bus} \cdot \bar{I}_{bus} \qquad (2.3.8)$$

It is desirable to determine a new voltage vector $\bar{E}_{bus}$ after the addition of a capacitor. The capacitor is considered as a "disturbance" of the state of equilibrium represented as an injected current, ΔI. Then

$$\bar{E}_{bus}(new) = \bar{E}_{bus}(old) + \Delta\bar{E}_{bus} \qquad (2.3.9)$$

or

$$\bar{E}_{bus}(new) = \bar{Z}_{bus} (\bar{I}_{bus} + \Delta\bar{I}_{bus}) \qquad (2.3.10)$$

or

$$\Delta\bar{E}_{bus} = \bar{Z}_{bus} \cdot \Delta\bar{I}_{bus} \qquad (2.3.11)$$

The increment in voltage due to the capacitor currents is shown in equation (2.3.11). Now when adding such a capacitor (ΔQ_k) at bus K, the expression for power flow becomes

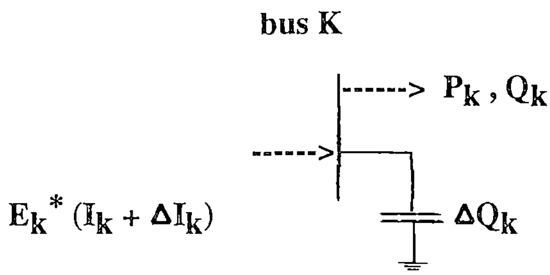
$$-P_k - jQ_k + j\,\Delta Q_k = E_k^* (I_k + \Delta I_k) \qquad (2.3.12)$$

Assuming that ΔQ_k is to be very small so that ΔE_k is negligible.
Therefore

$$j\,\Delta Q_k = E_k^* \cdot \Delta I_k \tag{2.3.13}$$

or

$$\Delta I_k = j\,\frac{\Delta Q_k}{E_k^*} \tag{2.3.14}$$



This injection current at bus K will cause a voltage change in all other buses that can be approximated by equation (2.3.11).

$$\begin{bmatrix} \Delta E_1 \\ \Delta E_2 \\ \cdot \\ \cdot \\ \Delta E_K \\ \cdot \\ \cdot \\ \Delta E_N \end{bmatrix} = \begin{bmatrix} Z_{11}\, Z_{12} \cdot\cdot Z_{1K} \cdots Z_{1N} \\ Z_{21}\, Z_{22} \cdot\cdot Z_{2K} \cdots Z_{2N} \\ \cdot \\ \cdot \\ Z_{K1}\, Z_{K2} \cdot\cdot Z_{KK} \cdots Z_{KN} \\ \cdot \\ \cdot \\ Z_{N1}\, Z_{N2} \cdot\cdot Z_{NK} \cdots Z_{NN} \end{bmatrix} \begin{bmatrix} 0 \\ 0 \\ \cdot \\ \cdot \\ \Delta I_k \\ \cdot \\ \cdot \\ 0 \end{bmatrix} \tag{2.3.15}$$

or

$$\Delta E_i = Z_{iK} \cdot \Delta I_K = Z_{iK} \left(\frac{j\,\Delta Q_K}{E_K^*}\right) \tag{2.3.16}$$

A sensitivity measure can now be associated to each bus defined as a sum of the changes in voltage of all low-voltage buses.

$$Z_{test}(K) = \Sigma\, \Delta E_i = \Sigma\, Z_{iK} \left(\frac{j\,\Delta Q_K}{E_K^*}\right) \tag{2.3.17}$$

where the summation is to be taken over all low-voltage buses. Note that this sensitivity measure is dynamic, since the number of buses with depressed voltage decreases as capacitors are added to the system. For every low voltage bus, the test is performed and the bus with the highest Z_{test} is selected for the next capacitor addition.

b) Capacitor unit size

Each bus has a maximum size of capacitor unit, which is calculated based on maximum acceptable voltage change. If the bus is selected as a prospective capacitor location, this size will be used in the process of building up a bank. The following constraint is to avoid switching problems during normal operations, for emergencies, this constraint may by increased.

$$\Delta E_K \leq 4.5\%\ E_K(\text{old}) \tag{2.3.18}$$

where ΔE_K: total voltage increase of bus K due to connection of capacitor.

$E_K(old)$: initial voltage magnitude at bus K.

An approximate calculation of the capacitor unit size is based on the use of three phase fault level at the capacitor bus.

$$\Delta E_K = \frac{\Delta Q_k}{MVA_{sc}} \cdot E_K(old) \qquad (2.3.19)$$

where MVA_{sc}: three phase fault level at bus K before capacitor installed.
ΔQ_k: capacitor unit size
ΔE_K: the increment in voltage permissible.

The permissible capacitor unit size is calculated as:

$$\Delta Q_k \leq MVA_{sc} \cdot \Delta E_K \qquad (2.3.20)$$

or

$$\Delta Q_k \leq MVA_{sc} \cdot [4.5\% \; E_K(old)] \qquad (2.3.21)$$

c) Reactive power conpensation requirement

Once the most sensitive bus for capacitors has been selected, the capacitor unit size is then calculated. This unit is of a discrete size according to current market standards.

After one capacitor unit has been added at bus K and a new corresponding voltage level has been reached, all buses are checked for the following constraints through AC load flow simulation.

$$E_i(new) \leq E_i(max) \qquad (2.3.22)$$

$$\Delta E_K \leq 4.5\% \; E_K(old) \qquad (2.3.23)$$

If either one is violated, the last added capacitor unit is removed from the system and the initial conditions are restored. And a new search for the "best" bus is initiated.

When contraints in equations (2.3.22) and (2.3.23) are met, the lower limit of voltage is checked for all buses.

$$E_i(new) \leq E_i^{min} \qquad (2.3.24)$$

If all buses have a voltage within specified upper and lower limits, the problem is solved and the amount of reactive power compensation requirement is printed. If one or more buses are still below minimum voltage, a new capacitor allocation routine is started.

Note that for each contingency case a unique reactive correction pattern is required in order to correct the resultant voltage drops at the load buses. The capacitor allocation logic is being extended to cover multiple outage conditions by using of fractionally switched banks. The logic is similar to the procedure implemented in capacitor allocation except that, instead of having only one single capacitor bank, additional ones will be the multiple switchable units which represent for each system condition. The results specify capacitor banks that can be fractionally switched on or off depending on the type of outage or generation changes.

2.4 NETWORK STABILITY MARGIN ANALYSIS - CONTINGENCY SELECTION

Since power equipment is designed to be operated within certain voltage limits, most pieces of equipment are protected by automatic devices that can cause equipment to be disconnected if these limits are violated. If an outage occurs on a system that causes violation of voltage limits, a series of further uncontrolled outages may follow. If this process continues, the entire system or large parts of it may completely collapse. This is usually referred to as a system blackout.

In general, voltage instability leading to system collapse appears to be due to the inability of networks to meet a demand for reactive power at certain critical buses. Practical control algorithms to prevent voltage collapse should identify the critical buses in the network and maintain control on voltages at these buses in particular. It has been seen that the problem of voltage instability and the allocation and amount of reactive power reserves are closely related.

To ensure the situation of voltage collapse is avoided, the reactive power reserves must be located properly. The knowledge of the reactive power reserve conditions is important in operation of a transmission network and will act mainly on the reliability and flexibility on performance of the power system. The planning criteria applied to the allocation of reactive power will be essential in the improvement of system security level with respect to various load situations and outage conditions.

In the following section a method of determining the system security margin, which defines the distance to voltage instability condition, is presented. This method is recommended as a tool to find the worst case from the contingency test. Once the worst case has been found, A study on reactive power compensation requirement for the network in that outage condition is carried out to identify dispersed VAR supply for the purpose of maintaining voltage profiles within specified limits, and increasing the security margin of anticipated operating conditions with respect to voltage collapse.

2.4.1 DETERMINATION OF VOLTAGE STABILITY LIMIT IN SIMPLE POWER SYSTEMS

In order to understand voltage collapse problem, a simplified case of system configuration represented in figure 2.4.1 is discussed.

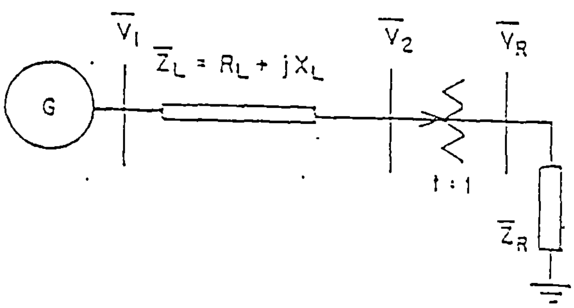


Figure 2.4.1 A simple system

$$\bar{Z}_R = Z_R \angle \phi$$

$$\bar{Z}_L = Z_L \angle \zeta$$

$\bar{V}_1$ is a constant voltage source.

Letting $$\bar{Z} = \frac{\bar{Z}_L}{\bar{Z}_R} = Z \angle \theta$$

it can be shown that

$$V_R = \frac{t\, V_1}{[\,(t^2 + Z \cos\theta)^2 + (Z \sin\theta)^2\,]^{1/2}} \qquad (2.4.1)$$

Normal operations of the OLTC transformer involves turns ratio adjustment corresponding to a change in V_R. If V_L drops, t is decreased thereby raising V_R. Thus $\Delta t < 0$ implies $\Delta V_R > 0$ for stable operation. However, if $\Delta t < 0$ results in $\Delta V < 0$, the receiving end voltage will be reduced further, indicating voltage collapse. Therefore, for voltage stable operation of this system,

$$\frac{d\,V_R}{dt} < 0 \qquad (2.4.2)$$

Combining equation (2.4.1) and (2.4.2) we find the corresponding condition

$$Z < t^2 \qquad (2.4.3)$$

Hence for voltage stability,

$$\frac{|\bar{Z}_L|}{|\bar{Z}_R|} < t^2 \qquad (2.4.4)$$

Assuming that the operating value of t is equal 1 (the nominal value)

$$\frac{|\bar{Z}_L|}{|\bar{Z}_R|} < 1 \qquad (2.4.5)$$

Hence, for normal operations $|Z_R| > |Z_L|$.

Figure 2.4.2 shows the variations of V_R against MVA demand S_R.

Point A (where $V_R = V_R^{critical}$) represents the critical system state. The upper segment ($V_R > V_R^{critical}$) is considered the stable operating region. ie.

$$\frac{|\bar{Z}_L|}{|\bar{Z}_R|} < 1,$$

in this region, increasing the sending end voltage increases the receiving end .

The lower segment is the unstable region, in this region, increasing the sending end voltage actually reduces the receiving end voltage.

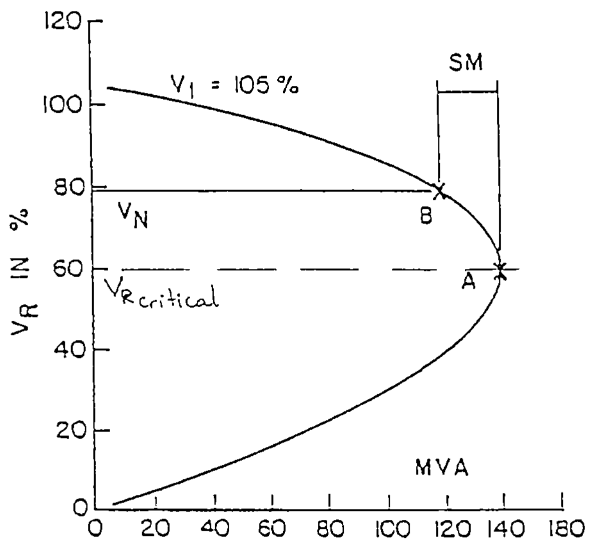


Figure 2.4.2: The variations of V_R against S_R.

The critical point corresponds to the condition $|\bar{Z}_R| = |\bar{Z}_L|$, which is the condition under which the maximum available power is obtained at the receiving end. This power is

$$\bar{S}_R^{max} = \frac{1}{4}\frac{e^{j\phi}}{COS^2\,[(\zeta - \phi)/2]}\frac{V_1^2}{Z_L} \qquad (2.4.6)$$

The corresponding load voltage, which is the minimum stable voltage at the load terminal is

$$\bar{V}_R^{critical} = \frac{\bar{V}_1 \quad e^{-j(\zeta - \phi)/2}}{2 \quad COS\,[(\zeta - \phi)/2]} \qquad (2.4.7)$$

The theory given here may be extended to the multi-node case with ideal voltage source. But the above results cannot, however, be applied simply to multi-machine power system networks owing to the fact that synchronous generators are not ideal voltage sources.

2.4.2. DETERMINATION OF VOLTAGE STABILITY LIMIT IN MULTIMACHINE SYSTEMS

The problem of determining the voltage stability of a general multimachine power network is formulated as a nonlinear optimization problem ie.

Maximise [Total MVA demand]   for a given transmission configuration.

Subject to:

a) Distribution of increase of the MVA demand at all load buses
b) MVAr and MW limits on generators
c) Generators MW participations
d) Constant power factor of MVA demand
e) Limits on controlled voltages and OLTC transformer taps.

With regard to above constraints, consider a power system to have N buses; buses 1 to M are generators buses and buses M+1 to N are load buses. The 1st bus is assumed to be the slack bus. The respective constraints are formulated as follows:

a) Distribution of increase of the MVA demand at all load buses. These contraints describe and enforce the pattern of increase of the MVA demand vector S, where

$$S^T = [\, S_{M+1}, S_{M+2}, ..., S_N \,] \tag{2.4.8}$$

A vector ß has been introduced for the distribution pattern of the MVA demand be specified.

$ß_i$ is a per unit value representing the relative increase in the load at bus i with respect to the corresponding system total load increase, ie.

$$S_i^{new} = S_i^{initial} + ß_i \, \Delta S_T \tag{2.4.9}$$

Where

$$ß_i = \frac{S_i^{initial}}{S_T^{initial}} = \frac{S_i^{new}}{S_T^{new}} \tag{2.4.10}$$

$$\Delta S_T = S_T^{new} - S_T^{initial} \tag{2.4.11}$$

$S_i^{initial}$ is the initial known MVA demand at bus i.

S_i^{new} is the new MVA demand at bus i after an increase ΔS_T in the total MVA load of the system.

and

$$S_T = \sum_{J_L} S_i \tag{2.4.12}$$

Where J_L = [M+1, M+2, ..., N] : load buses

b) MVAr and MW limits on generators:

In determining the system voltage stability limit, it is necessary to take the power production capabilities of the system generating units into account. These constraints limit the MVAr and MW outputs from system generators to their respective specified limits, ie.

$$P_i^{min} \leq P_i \leq P_i^{max} \tag{2.4.13}$$

$$Q_i^{min} \leq Q_i \leq Q_i^{max} \tag{2.4.14}$$

$$i = [\, 2, 3, ..., M \,]$$

c) Generator MW participation:

As the load increases, the MW output of each generating unit is increased from the base point to "participate" in the load change. For this purpose, the participation factors are specified in a vector γ, where γ_i is the specified participation factor of generator i. The total system demand P_D is expressed as:

$$P_D = \sum_{J_L} P_j + P_{losses} = \text{Total MW load + Losses} \tag{2.4.15}$$

$$\gamma_i = \frac{\Delta P_i}{\Delta P_D} = \frac{P_i^{new} - P_i^{initial}}{P_D^{new} - P_D^{initial}} \tag{2.4.16}$$

Where $P_D^{initial}$ and $P_i^{initial}$ are the initial total system MW demand and initial MW output of generator i, respectively. Hence we have:

$$P_i^{new} = P_i^{initial} + \gamma_i \, \Delta P_D \tag{2.4.17}$$

d) Constant power factor of MVA demand:

The power factor of the incremental load at each load bus may be assumed to retain constant at a specified value. This optional constraint set which allows control with the power factor of the load increases is enforced by the following requirement:

$$\Delta P_i = pf_i \, \Delta S_i \tag{2.4.18}$$

Where

ΔS_i is the MVA load increase at bus i

ΔP_i is the MW load increase at bus i

pf_i is the power factor of load increase at bus i.

e) Limits on controlled voltages and OLTC transformer taps:

A tap changer controlled voltage is allowed to vary within specified limits if the tap setting is not at its limits.

The solution of this optimization problem is the system state at the critical point (stability limit) and the corresponding value of the total MVA load (ie. S_T^{limit}).

2.4.3. SECURITY MARGIN

Having determined the system critical state, the security margin SM is defined as:

$$SM\,(\%) = \frac{\sum_{J_L} S_j^{limit} - \sum_{J_L} S_j^{initial}}{\sum_{J_L} S_j^{limit}}$$

$$SM\,(\%) = \frac{S_T^{limit} - S_T^{initial}}{S_T^{limit}} \qquad (2.4.19)$$

Where S_j^{limit} is the MVA load at bus j at the critical state.

For a stable initial operating conditions, SM takes on values between 0 to 1. SM = 0 at the voltage stability limit (critical point). A negative value of SM means that the network is unable to supply the specified initial MVA demand.

Note that the SM value will be used to define the distance to voltage instability condition. The most serve contingency case is chosen to be the one with the smallest value of SM. VAR support is then determined to achieve satisfactory voltage levels and security margins. The typical values of the required voltage level and security margin condition for all system states are:

$$V^{min} = 0.95 \text{ p.u}$$

$$V^{max} = 1.05 \text{ p.u}$$

$$SM \geq 10\,\%$$

3. BACKGROUND ON EXPERT SYSTEMS

An expert system is a computer program system that behaves like an expert in some domain. Each system has knowledge in a particular domain and is capable of solving problems that require that knowledge.

Expert systems derive their power from the problem domain knowledge they possess and from their use of heuristics (rules of thumb) in going about their problem solving activities. They can be used as computer-based consultants to humans in the performance of complex tasks. Such as the real time voltage-Reactive power control.

Expert systems are particularly useful for making expert advice readily accessible, so that non-experts can use expert systems to solve problems in a comparable way to domain experts.

Development of an expert system can be conveniently divided into three main modules: a knowledge base, an inference engine and an user interface.

(i) The knowledge base comprises knowledge that is specific to the domain of application, including such things as simple facts about the domain, rules that describe relations or phenomena in the domain, and possibly methods, heuristics and ideas for solving problems in the domain. Knowledge can be structured into production rules, each of which represents a single piece of knowledge and takes the form of:

IF (antecedent)
Then (consequent)

When the antecedent of a rule is satisfied, the current rule may fire, and the consequent is performed, perhaps satisfying the antecedent of another rule.

(ii) The inference engine applies the knowledge base to solve a problem. It directs or controls the operation of the expert system, deciding which rules to apply, how they will be applied, when the process is completed and when a possible solution can be suggested. There are two common control or inferencing mechanisms, known as forward chaining and backward chaining.

A forward chaining system attempts to watch known facts with antecedents of production rules, and fires the rules accordingly. Executing the consequents of these rules adds new facts to the knowledge base. This continues until either a goal consequent is performed and the system stops, or the available facts can not be used to infer any other new fact, and the result is unknown.

A backward chaining system is initiated by goal hypotheses. The system attempts to see if the goal hypotheses are correct, by determining whether the antecedent(s) of rule(s) which cause the hypotheses to be established, are satisfied. This, in turn, causes consideration of further rules which would confirm the required antecedent(s).

(iii) The user interface provides smooth communication between the user and the system. It also provides the user with an insight into the problem-solving process executed by the inference engine. It is convenient to view the inference engine and the interface as one module.

3.1. THE EXPERT SYSTEM SHELL - VP-EXPERT

The expert system shells reduce the amount of resources required for the development of expert systems, with already implemented data structures (rules, frames, objects), and inference mechanisms. Hence building an expert system requires adding domain-specific knowledge to one such shell.

A software package called VP-EXPERT is selected to be used as the expert system shell because it is cheap (about AUS $600.00), and it offers most user-interface requirements.

An expert system shell such as VP-EXPERT is basically an inference engine. It can be used to reason about many different knowledge bases. This is the reason why building an expert system using VP-EXPERT is easy.

The VP-EXPERT is flexible, portable, provides support for external software such as high-level programming languages, databases and graphics, and runs on MS/DOS.

The VP-EXPERT 's inference engine provides both forward chaining and backward chaining facilities. It also allows user to create highly graphical user interfaces, supplying the user with easy implementation of both horizontal and vertical gauges, intelligent blank fields, meters, and buttons. Hypertext links are available, as are pop-up menus and mouse control.

3.1.1. VP-EXPERT 's RULES

In VP-EXPERT, reasoning knowledge can be expressed by using RULEs. A RULE expresses the expertise contained in an expert system through IF/THEN conditional statements called RULE statements.

In its simplest form a RULE must have an antecedent (the IF part) and a consequent (the THEN part). VP-EXPERT 's format is:

```
IF          <set of conditions>
THEN        <hypothesis>
    and do  <set of actions>
BECAUSE     <set of explanations>
```

When a set of conditions are met, the rule can be fired or applied, the hypothesis or goal becomes true, and the set of actions are performed. A set of explanations shows how the rule reaches its conclusions.

3.1.2. VP-EXPERT 's CONTROL STRATEGY

In order to reach its goal, VP-EXPERT 's inference engine systematically searches for new values to assign to appropriate variables that are present in the knowledge base. Thus it has the capability to add to the known store of knowledge.

When a rule is fired, the inference engine begins to search for a value to be assigned to its associated goal variables. If the value assigned to that goal is not known, the inference engine searches the RULE base for a value to assign to that goal. Initially not all variable values which might aid in the search are known. Thus the search must systematically accumulate new knowledge by considering RULEs from the RULE base which might yield helpful facts in the process of finding the goal. VP-EXPERT does this via a search method commonly called backward chaining. In addition, forward chaining is supported to its original extensive backward chaining facilities.

4. EXPERT SYSTEM DEVELOPMENT

This section presents the development of an expert system for voltage control/ reactive power compensation to restore the voltage profile.

The expert system block diagram is shown in figure 4.1. For the solution of system voltage control and reactive power compensation problem, the knowledge base is identified and expressed in terms of production rules in sections 4.2.

Based on the identified knowledge and the production rules, the inference engine is developed in section 4.3 on the basis of using the sensitivity tree technique to analyse the relationship between the bus voltages and the control measures for voltage control.

4.1. BLOCK DIAGRAM OF THE EXPERT SYSTEM

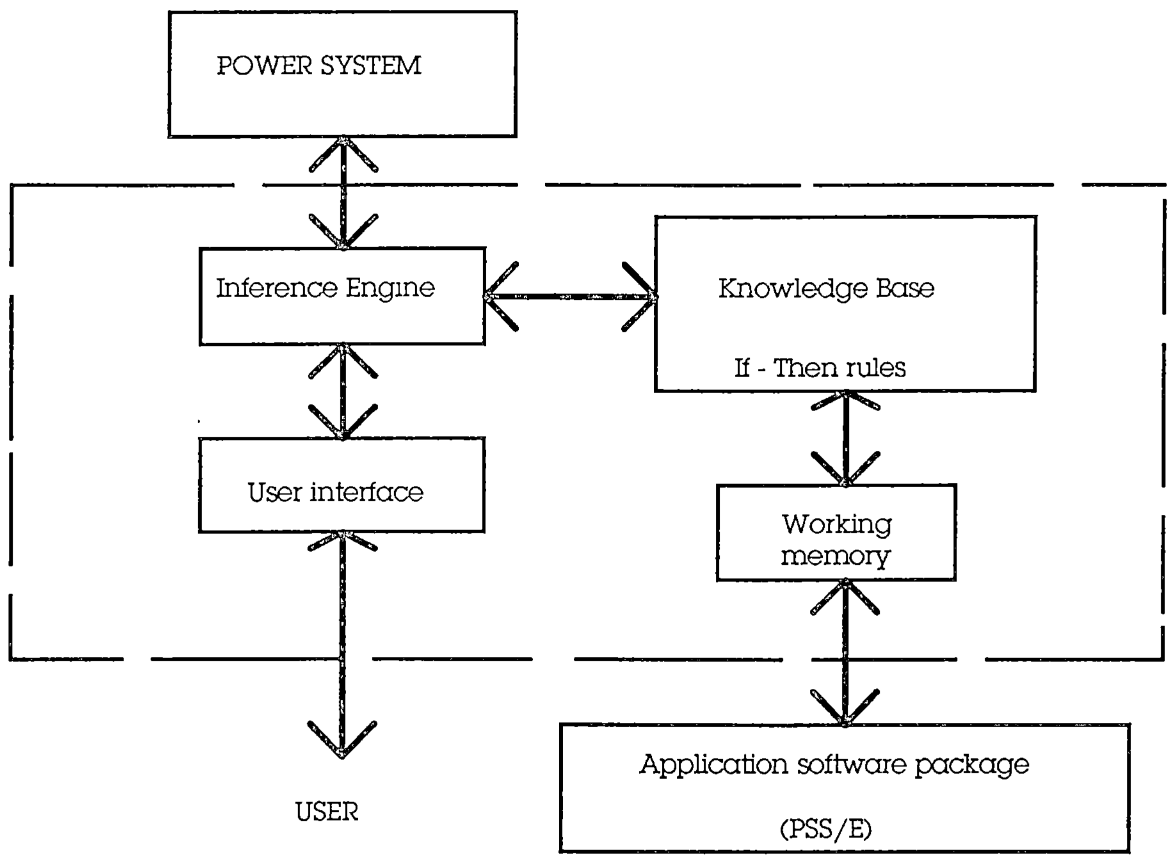


Figure 4.1: Block diagram of the expert system for voltage/reactive power control.

4.2. THE KNOWLEDGE BASE

In the voltage and reactive power control expert system developed, the following knowledge is needed to form the knowledge base:

- The upper and lower limits of voltage at each bus

- The upper and lower limits of each control measure

- A sensitivity factor table for each load bus voltage and the control measures. (The system may operate in different configurations for which the sensitivity factors may be quite different).

It is well known that to maintain bus voltages within certain upper and lower limits is a practical requirement in power system operation. When a bus in a power system has an abnormal voltage, either high or low, the usual approach is a despatcher takes is to switch a capacitor bank, adjust the tap positions of transformer tap changers or vary the generator bus voltage to restore a normal voltage profile.

When a low voltage is present, a capacitor bank or synchronous condenser provides reactive power to the power system, raising load bus voltages. The tap changer can adjust the secondary/ primary turns ratio of a transformer and hence increase the secondary voltage magnitude. As the tap positions are raised, however, the total reactive power demand of the power system may increase as a result of the higher secondary voltage.

Sometimes, a voltage problem cannot be solved by adjusting the existing reactive power sources, then the additional shunt capacitor should be installed in the system to formulate the low voltage problem.

Empirical rules exist for the Voltage-Reactive power control of power systems. An experienced power engineer can select appropriate control actions to resolve a voltage problem efficiently. The existence of empirical knowledge forms a good basis for an expert system approach. Based on this philosophy, the expert system for voltage/ reactive power control was developed and used forward chaining inference mechanism to improve the processing speed. To design an effective expert system, it is crucial to develop a high quality knowledge base. The knowledge base should contain the knowledge required to perform the task well. For the voltage / Reactive power control problem, the following rules are identified:

1_ If a load bus voltage drops below the operating limit, control devices such as: Shunt capacitors, transformer taps, generator voltages and synchronous condensers can be switched or adjusted to restore the voltage profile.

2_ If a load bus voltage drops below the operating limit, it is most efficient to apply the reactive power compensation locally (ie. which has highest sensitivity value). If the capacity of local compensators is insufficient to restore the voltage problem, then compensators with next highest sensitivities should be chosen.

3_ If the low voltage problem occurs at a bus, the tap position of the local transformer tap changer can be adjusted to correct the problem. However, increasing the tap position may cause other load bus voltages to drop.

4_ Generator bus voltages can be raised to solve the low load bus voltage problems.

Note that the Voltage / Reactive power control adjustment planning has covered the estimations of required amount of additional installation of shunt capacitors to ensure to have enough VAR source facility for maintaining proper voltage under the normal condition and under the single contingency conditions.

The knowledge required to perform the task was expressed in terms of production rules (IF-THEN structures). This implementation was written in the production system language, IPLAN, which is similar to FORTRAN and utilizes a backward chaining mechanism for inference. The following is a list of the knowledge-based programs and their function:

- Outage.IPL:

This program provides a selection to the user on system contingency outage condition.

- SM.IPL:

This program calculates the voltage stability limit of the power network for different system configurations, that will be used for selecting an appropriate configuration for Voltage / Reactive power control study.

-SEN.IPL:

This program calculates sensitivity factors of the power network. These factors will be used in determining the minimal adjustments to the reactive power control variables required to alleviate voltage violation problems.

- VCONTROL.IPL:

This program provides bus voltage control. When a voltage problem occurs, control measures such as switched shunt capacitors, transformer taps and generator voltages are utilized to provide a voltage correction according to their sensitivity value.

- CAPPLAN.IPL:

This program is used in selecting locations and estimating sizes of the additional shunt capacitors, which need to be installed in the network to overcome the voltage violation problem.

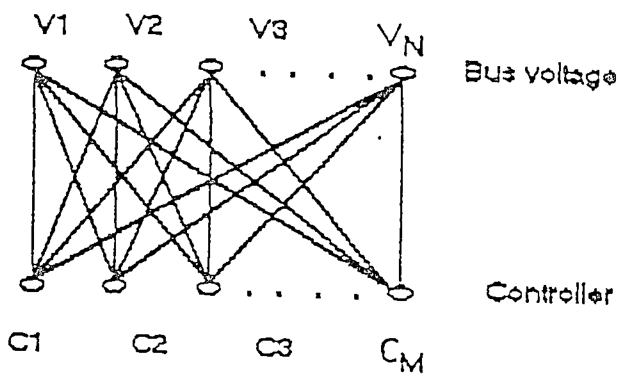
Note that the flow charts of these IPLAN programs are shown in section 5.3.

4.3. INFERENCE ENGINE-USE OF THE SENSITIVITY TREE

The inference engine is used to chain the facts given in the knowledge base and the basic rules. The fundamental ideas for the development of the basic rules and the inference engine for the proposed expert system are outlined here.

In order to easily analyse the relationship between the bus voltage and the control measures the sensitivity trees are used to represent the system relationships.

For an N bus power system with M control measures, the relationship between the bus voltages and the control measures can be represented as shown in figure 4.3.1.



(a)

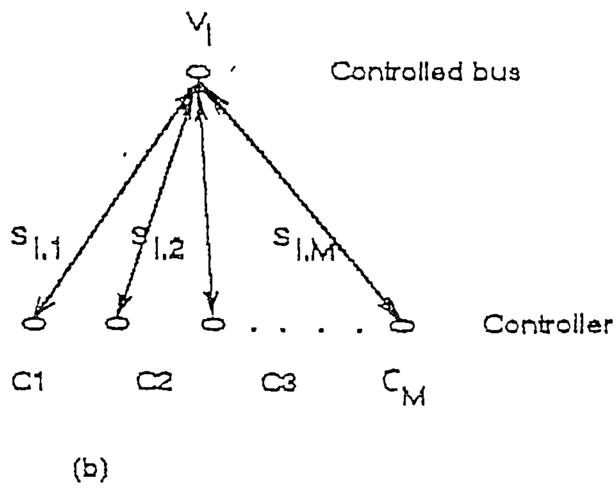


Figure 4.3.1. Representation of the voltage control - sensitivity tree

Note that $S_{i,k}$ are the sensitivity factors between the control measures and the load bus voltages.

The root of the tree is the controlled bus voltage. Each root connects the control measures through branches. The sensitivity factor associated with the controlled bus voltage and the control measure is given on the corresponding branch.

It can be seen that for each bus voltage, several control measures can be used for adjustment. It can also be seen that changes in each control measure result in changes of several bus voltages. For a certain bus voltage violation, it is possible to calculate by using the sensitivity technique the control action needed to overcome this voltage violation. Two facts limit the control action. First, the control action should not exceed the control constraints. Second, the control action used to overcome the voltage violation should not produce new bus voltage violations.

Based on the sensitivity tree, the basic rules and the inference engine of the proposed voltage and reactive power control expert system are developed. The following procedure involves a series recursive searches, which can be realized in IPLAN language. Note that, for convenience of implementation and efficiency of execution, the procedure is divided into a number of tasks. Each task corresponds to a particular, modular function. These tasks (IPLAN programs) and their functions were shown in the previous section 4.2.

VOLTAGE CONTROL MODULE:

1. The expert system is started by asking the user to seclect a contingency outage from the network one-line diagram shown on screen. The system security margin for this outage is then calculated, which will be used to formulate the critical condition of the outages.

2. Next, the expert system identifies the system operating configuration and calculates the network sensitivity factors. The sensitivity trees of voltage control are built and stored in an external file (SEN1.AAA). These trees will be used as the knowledge base.

3. Compare the current voltage magnitudes of each bus with their specified limits. Find the buses with abnormal voltage and the magnitude of the voltage violations.

4. Monitor the buses with voltage violation.

5. Identify the bus with maximum violation.

6. For this maximum violation bus, sequentially search for the most effective (the highest weighted sensitivity) control measure by using the sensitivity tree, which was stored in the external file.

7. Calculate the control action needed to recover the voltage violation and check the control action from the controllers' contraints. If the control action exceeds the limit, the control limit is chosen as the control action. This calculation is made by using multi-loadflow simulations through the PSS/E software package. Note that it is guaranted that recovering proper voltage level at one bus does not cause bus voltage violations on other buses during the calculation. It is also guaranted that the control action has to be suitable to the size for the adjustment if the control measure is a switchable shunt capacitor (the capacitor bank size is specified in an external file called "SWITCHCP.dat").

8. Check if the control action has exceeded the limit or the voltage violation does not decrease, this control measure is ignored, and the controller with next highest sensitivity factor is chosen.

9. Recalculate the new bus voltages after the control action.

10. Monitor the recommended control action and the new bus voltages after control action.

11. Repeat the procedure from (3) to (10) until the bus voltage violation has been overcome.

12. For large disturbances it may happen that even after all the possible voltage control measures have been used, the bus voltage violation still cannot overcome. In this case, a reactive power compensation module (ie. additional shunt capacitor installation) is needed.

13. Repeat the above procedure for each voltage violation bus until all bus voltages are within limits.

REACTIVE POWER COMPENSATION MODULE

1. Compare the current voltage magnitudes of each bus with their specified limits, find the buses with abnormal voltage and the magnitude of the voltage violations.

2. Monitor the buses with voltage violation.

3. Calculate the sensitivity factors based on Jacobian Z matrix and sensitivity test for the voltage violation buses.

4. Identify the bus with highest sensitivity factor, which is selected as the most sensitive bus for shunt capacitor installation.

5. Calculate the maximum bank size based on of the estimation fault MVA value and voltage variation permissible limit.

6. Calculate the amount of shunt capacitor needed to recover the voltage violation. It is guaranted that recovering proper voltage level at one bus does not cause bus voltage violations on other buses.

7. Recalculate the new bus voltages after the shunt capacitor installed.

8. Monitor the total MVAR of shunt capacitor needed, the maximum band size and the new bus voltages after the shunt capacitor installed.

9. Repeat the module from (1) to (8) until all bus voltages are within limits.

Figure 4.3.2 shows the details configuration of the developed expert system.

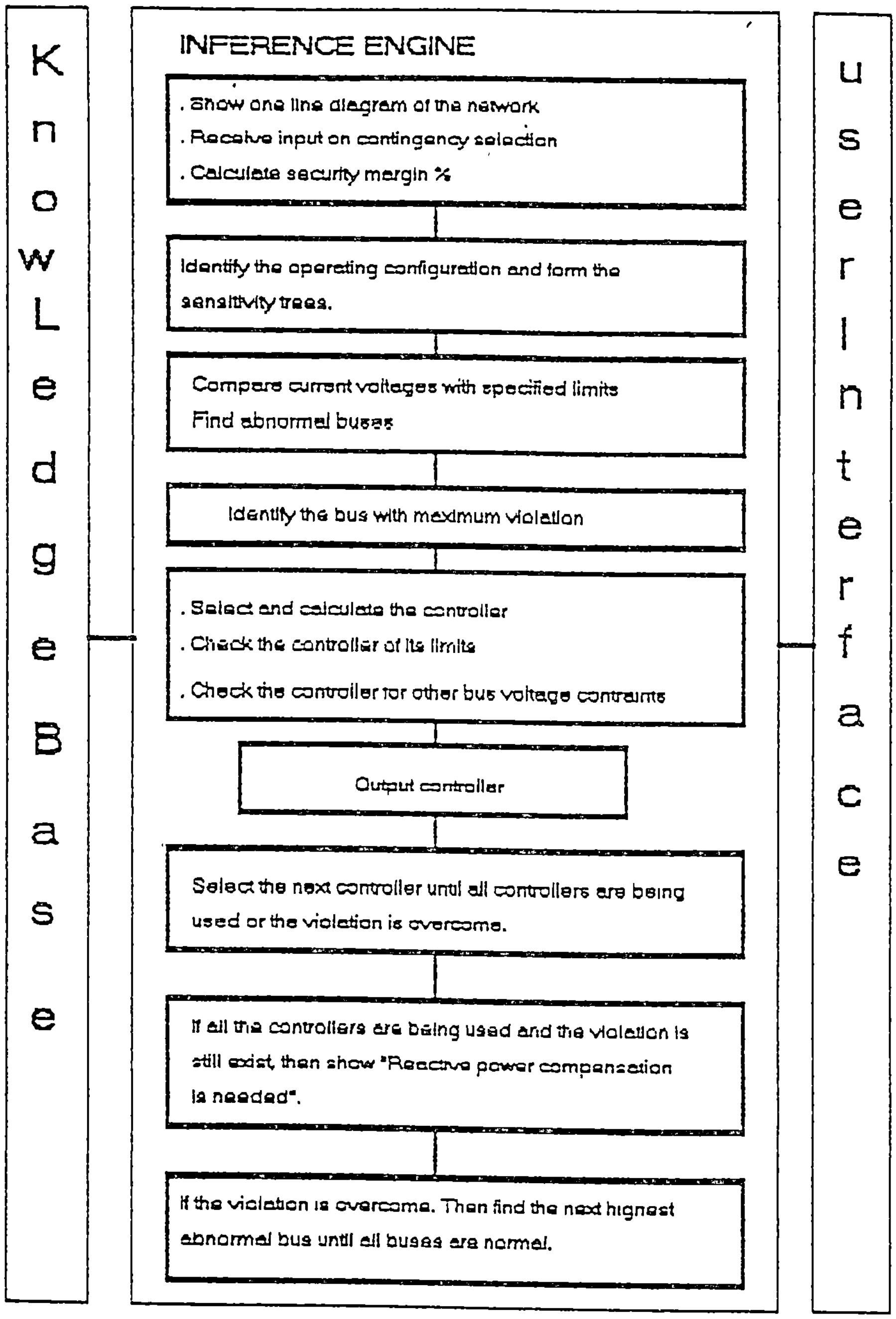


Figure 4.3.2: System configuration of the developed expert system

5. IMPLEMENTATION OF THE EXPERT SYSTEM

This section provides some details about the implementation of the expert system. The expert system is implemented on IBM personal computers or compatibles. The hardware and software requirements are listed in sections 5.1 and 5.2, respectively.

IPLAN language is used in writing the knowledge-based programs because this language has been designed to be utilized as a stand-alone product to control the existing power flow application programs such as PSSE. The flow charts of the knowledge-based programs are shown in section 5.3.

A software called VP-EXPERT is used as a tool for the user interface and to integrate the power flow software PSSE (Power System Simulator Engineering) .

Section 5.4 deals with the data structure of the expert system implemented in conjunction with the PSSE input data format.

MS-DOS batch files, LIST.COM and KEY-FAKE.COM are utilized in the expert system to provide the command sequences, input and output data to control the execution of the expert system.

Note that the PSSE software runs under control of DBOS, a so-called "DOS extender" written at the university of Salford, England; and PTI (Power Technologies Institution) has supplied an appropriate "run-time " version of DBOS.

5.1. HARDWARE REQUIREMENTS

- An 80386SX, 80386 or 80486 PC, with a hard disk
- A maths coprocessor (80287, 80387 or Weitek) is recommended
- At least 1MB of memory
- A EGA graphics board and monitor.

5.2. SOFTWARE REQUIREMENTS

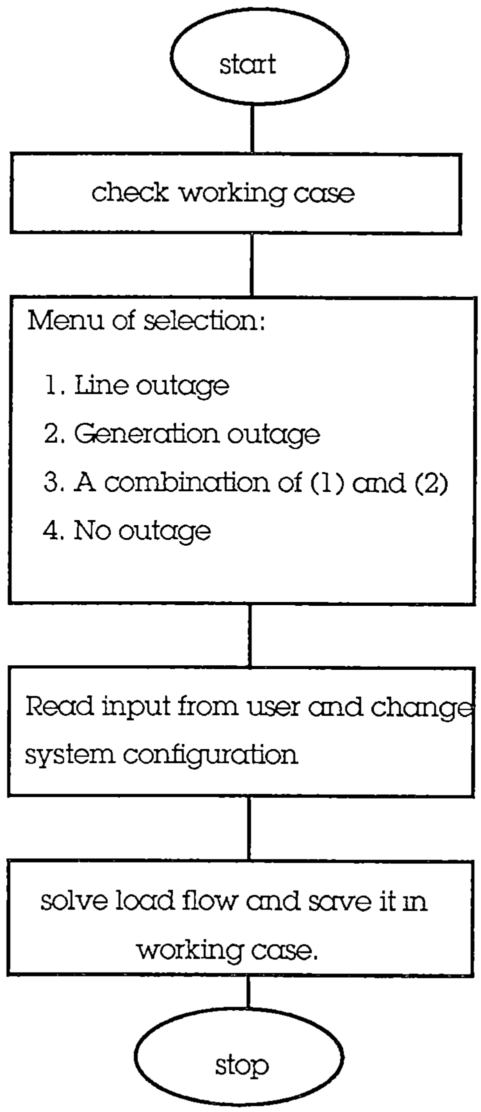
- MS/PC-Dos version 3.3 or higher
- DBOS version 2.51 or higher (or "run time" version)
- PSSE version 19 or higher
- VP-EXPERT version 2.0 or higher.

5.3. PROGRAM DEVELOPMENT

The following shows the flow charts of the IPLAN programs, which are used to build up the knowledge base of the expert system and to provide interface with PSSE through the expert system shell VP-EXPERT.

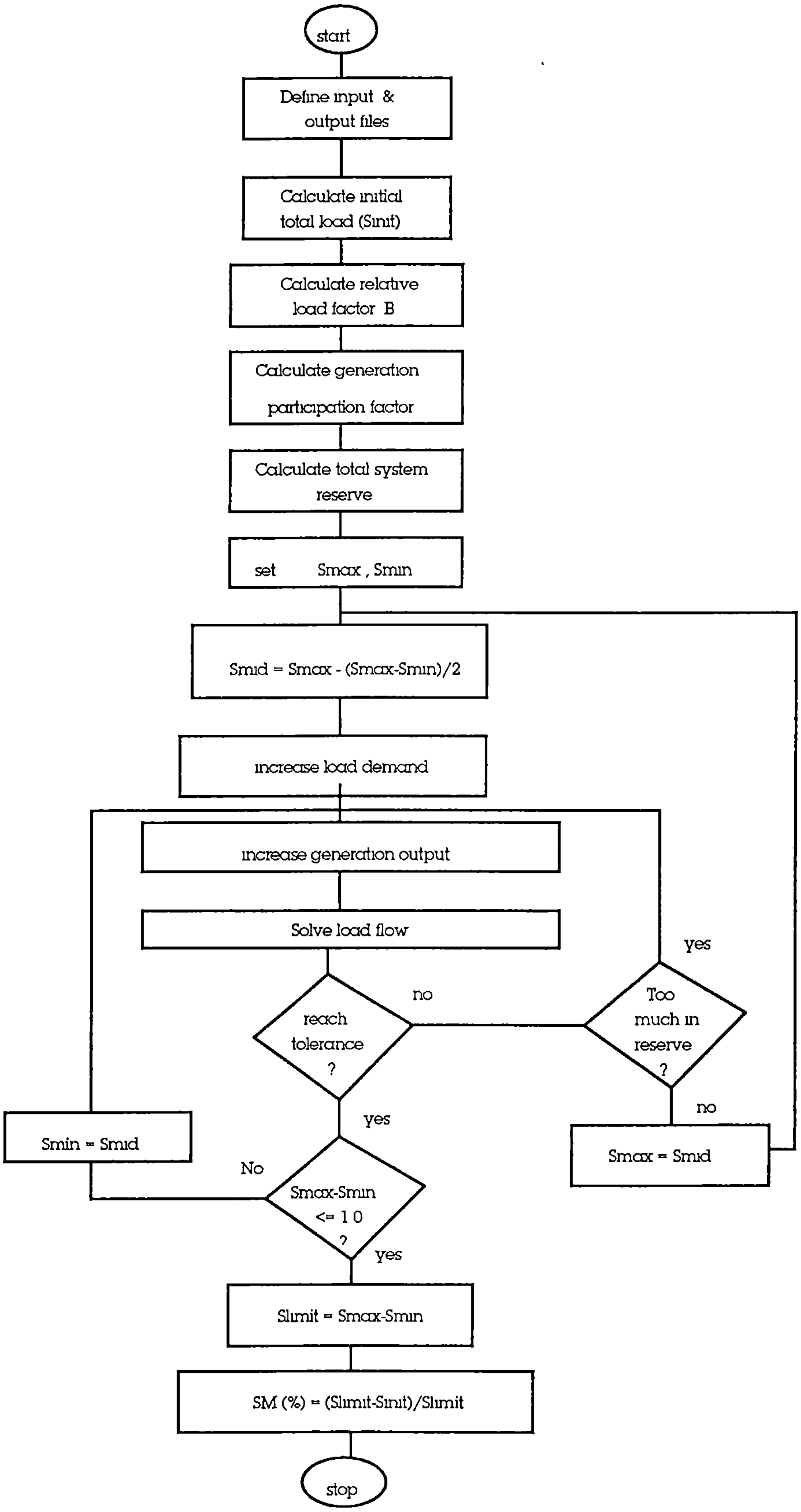
5.3.1. FLOW CHART OF CONTINGENCY OUTAGE SELECTION

The flow chart of an IPLAN program called "OUTAGE.ipl", which provides a selection to the user on system contingency outage condition, is shown as follow.



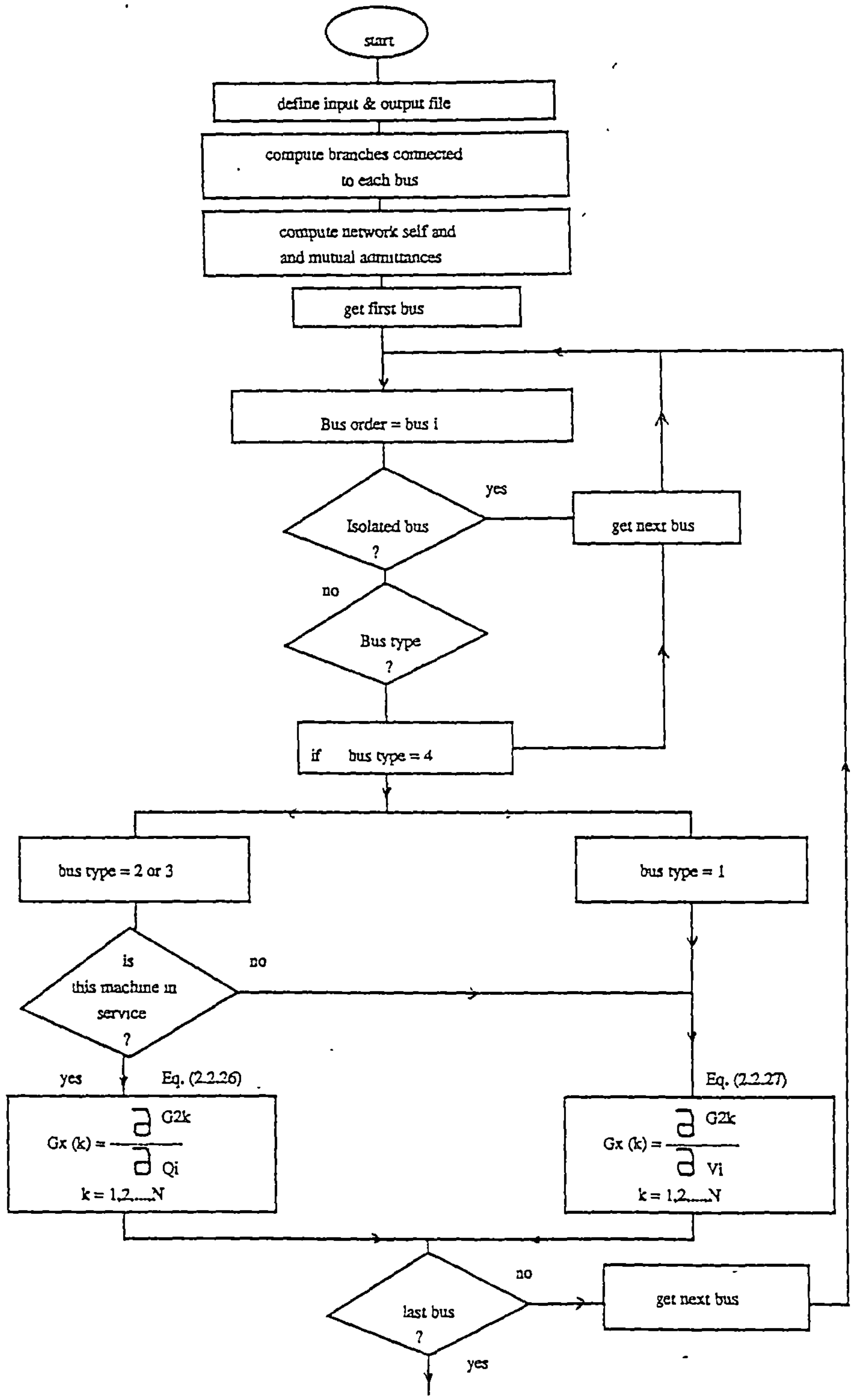
5.3.2. FLOW CHART OF POWER SYSTEM SECURITY MARGIN CALCULATION

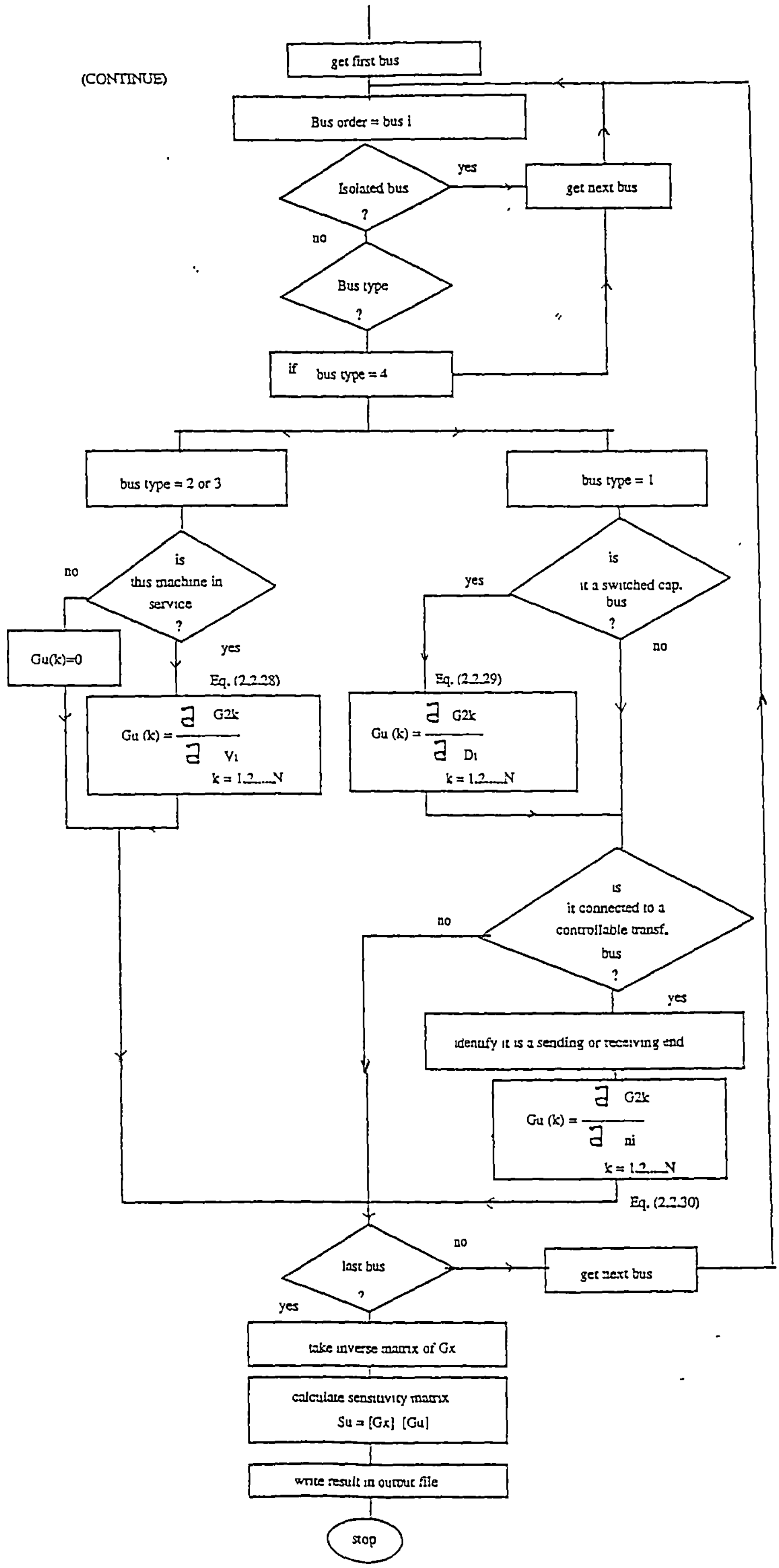
The flow chart of an IPLAN program called "SM.ipl", which calculates stability margin and critical voltage of multimachine power systems, is shown as follow.



5.3.3. FLOW CHART OF NETWORK SENSITIVITY ANALYSIS

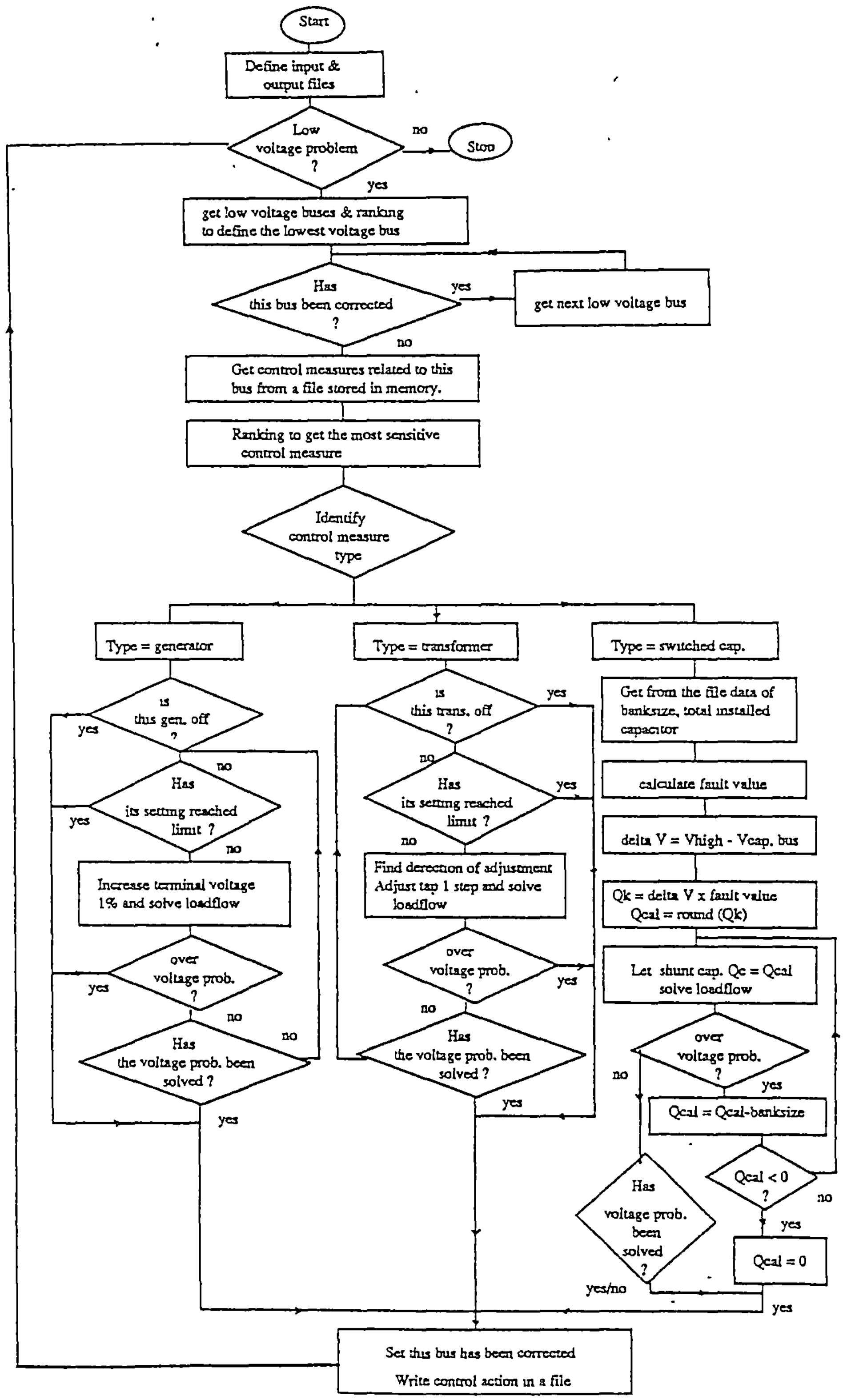
The following figure shows the flow chart of an IPLAN program called "SEN.ipl", which was developed to calculate the sensitivity matrix of power systems.




(CONTINUE)
get first bus
Bus order = bus i
Isolated bus ?
yes
get next bus
no
Bus type ?
if bus type = 4
bus type = 2 or 3
bus type = 1
is this machine in service ?
no
yes
Gu(k)=0
Eq. (2.2.28)
$Gu(k) = \frac{\partial G2k}{\partial Vi}$
k = 1,2,...,N
is it a switched cap. bus ?
yes
no
Eq. (2.2.29)
$Gu(k) = \frac{\partial G2k}{\partial Di}$
k = 1,2,...,N
is it connected to a controllable transf. bus ?
no
yes
identify it is a sending or receiving end
$Gu(k) = \frac{\partial G2k}{\partial ni}$
k = 1,2,...,N
Eq. (2.2.30)
last bus ?
no
get next bus
yes
take inverse matrix of Gx
calculate sensitivity matrix
Su = [Gx] [Gu]
write result in output file
stop

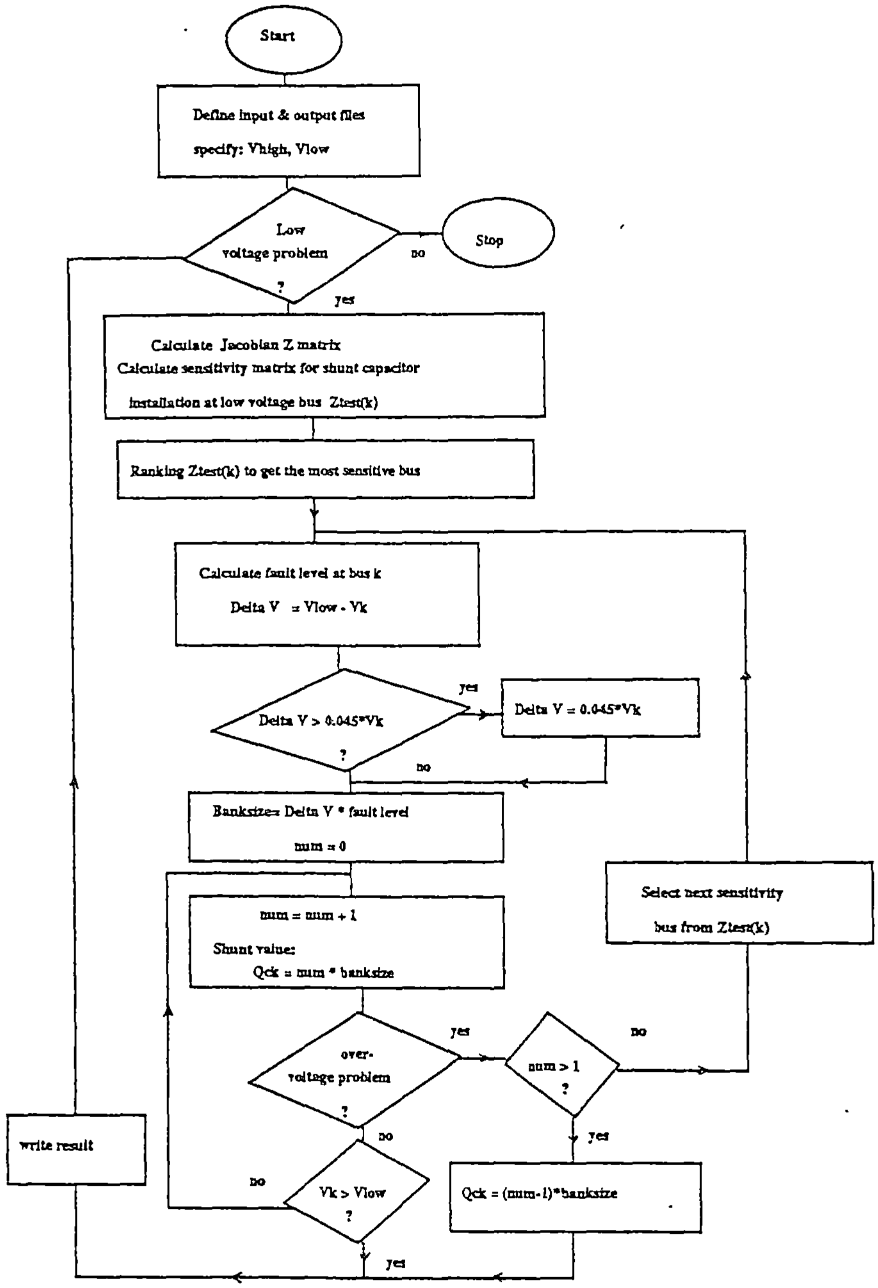
5.3.4. FLOW CHART OF VOLTAGE CONTROL

The flow chart of an IPLAN program called "VCONTROL.ipl", which provides voltage/VAR control by adjusting the existing reactive power sources, is shown as follow.



5.3.5. FLOW CHART OF ADDITIONAL CAPACITORS ESTIMATION

An IPLAN program called "CAPPLAN.ipl", which formulates the location and size of network additional capacitors, was developed incorporating the above procedure. The flow chart of this program is shown as follow.



5.4. DATA STRUCTURE

In general, it is desirable to have a data structure that is easy to read, efficient to process and easy to expand.

For power flow calculation, the power system information and the condition of the operations are required, such as: bus data, branch, generator, transformer, load, shunt reactive power etc. Hence a power flow data file is needed.

For the Voltage / Reactive power control problem, the expert system needs to acquire power system information. In this case, the most relevant data will be voltages and power demands of the problem (load) buses and the availability and limits on controllers. This information will be provided, as a result of power flow calculations, in the working memory records. In addition, a data file about the existing switched shunt capacitors is also required if the power system consists any switched shunt capacitors.

For convenience, all the power system data is given in form of the PSSE input data format. The structure of the power system data and the switched capacitor data is shown in appendix A.

6. EXPERT SYSTEM TESTING RESULTS

The goal of developing the expert system is to search the right control actions needed to correct the voltage violation problem in order to maintain all load bus voltages within certain upper and lower limits. If the suggested actions can correct the voltage problem, then the expert system is considered to function properly.

Two examples are given in this section to test the performance of application of the developed expert system. The first one is the AEP 14_bus system with some modifications. The second one is the North-East Tasmania subsystem.

For each example, the base case and the contingency cases (eg. line outage) are considered. By using the expert system to calculate the stability margin for these cases, as a result, the worst contingency case can be defined for the following voltage/ reactive power control and VAR support studies. After execution the voltage/ reactive power control and VAR support actions, the calculation of system stability margin is repeated to check the satifactory voltage control of the system, which is operated in new operating condition including VAR supported. Note that the total system losses is a factor which will be included in the expert system performance evaluation.

For each contingency case, the post-disturbance voltage profiles (initial voltage) and the final voltage profiles obtained after execution of the control actions and VAR support, suggested by the expert system, are given. Detailed control actions for voltage problem solving by the expert system are recorded. Tasks that performed by the expert system during problem solving process are also given. They include:

- Task 1: calculate the network sensitivity factors and construct the sensitivity trees.
- Task 2: voltage violation check
- Task 3: voltage correction

For performance testing the operating constraints are assumed as follows:

Table 6.1: SYSTEM SPECIFICATION

VARIABLE	LIMIT
Transformer Tap	0.90 - 1.10 p.u
Load bus voltage	0.95 - 1.05 p.u
Max. generator terminal voltage	1.06 p.u
Specified stability margin	> 10 %

6.1. AEP SYSTEM

The AEP 14-bus system [19] is chosen to demonstrate the usefulness of the expert system. The network one-line diagram and the network parameters are given in appendix C.

For this network the base case and five contingency cases are considered [10]. Table 6.1.1 shows the list of the contingencies and the computed security margin SM for each case, before taking VAR allocation, given by the expert system.

Table 6.1.1: System security margin for the contingency cases
[Before VAR allocation]

CASE No.	LINE OUTAGE	SM (%)
1	Base case (no outage)	16.35
2	100 - 200 (one of two lines)	11.63
3	100 - 500	2.38
4	200 - 400	5.62
5	600 - 1300	14.13
6	900 - 1400	15.34

By using multiple AC-load flow computations, the expert system computes the security margin SM of the system condition at the limit of total MVA load. Beyond the point, load flow solutions can not be obtained. The plot of load bus voltage variation against the increment of total MVA load of the system with full configuration is shown in Figure 6.1.1.

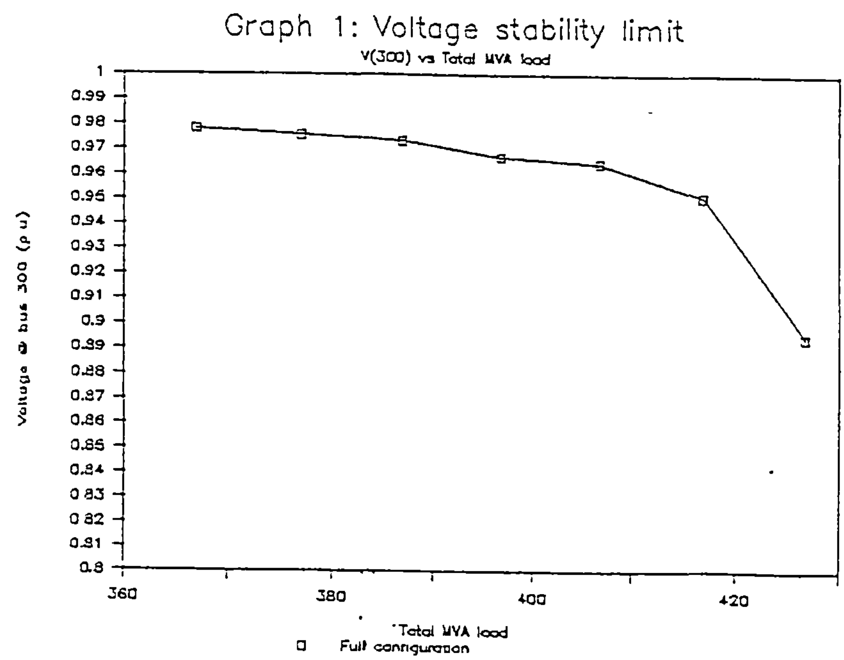


Figure 6.1.1: Voltage versus total MVA load at Bus 300.

It will be noted that some of the contingency cases have security margin (SM) that are lower than the required SM specified. VAR support is therefore considered for the network. It is also noted that to minimise the amount of VAR support installation, the voltage /reactive power control should be performed at the first stage.

As shown in Table 6.1.1, case 3 with SM of 2.38% is the most severe operating state and therefore selected for voltage/ reactive power control and VAR support study.

Detailed control actions for voltage/ reactive power control and VAR support problem solving by the expert system are recorded as follows.

(i). VOLTAGE/ REACTIVE POWER CONTROL

Contingency: Line 100 - 500 outage

a) Task 1: calculate the sensitivity factors for this sytem configuration and construct the sensitivity trees for all load buses.

b) Task 2: voltage violation check

* Number of voltage violations : 11
* The problem severity is : major problem (No. violated buses >= 3)

Low voltage detection:

Bus number	Voltage (p.u)
1200	0.76494
1400	0.77162
1300	0.78585
1000	0.78743
1100	0.79135
900	0.80441
600	0.82628
500	0.82808
400	0.82938
700	0.83419
1500	0.85681

* The worst problem is at bus 1200. Therefore the most effective control is selected at bus 1200.

c) Task 3: Voltage correction

Get the sensitivity tree for this controlled bus from the network sensitivity factors calculation for this outage:

Controlled bus: 1200

Sensitivity factors	Control measures	Description
- 0.44451	V 1600	Syn. condenser connected to bus 1600
- 0.21501	N 500-1500	Trans. connected between 500-1500
- 0.20825	V 200	Gen. connected to bus 200
0.20689	D 1300	S. capacitor connected to bus 1300

- 0.16767	V 800	Syn. condenser connected to bus 800
- 0.10330	V 300	Syn. condenser connected to bus 300
0.06634	D 900	S. capacitor connected to bus 900
- 0.04886	N 400-900	Trans. connected between 400-900
- 0.03888	N 400-700	Trans. connected between 400-700
0.00000	V 100	Gen. connected to bus 100

- Action 1: select the most sensitive control measure

** V 1600 : synchronous condenser connected to bus 1600 **

- controlled bus voltage = 0.76494 pu

- original setting at:

V schedule = 1.04 pu
V actual = 0.89414 pu

Because (V schedule > V actual). Therefore this controller is not suitable for adjusting.

*** controlled bus voltage < 0.95 pu. Then voltage control action is continued ***

- Action 2: select controller with the next highest sensitivity factor.

** N 500 - 1500 : transformer connected between buses 500-1500 **

- controlled bus voltage = 0.76494 pu

- original setting at:

Tap = 0.932

Because (0.9 < Tap < 1.1). Therefore this controller tap can be adjusted to:

- New setting at:

Tap = 0.90075

- controlled bus voltage = 0.79404 pu

*** controlled bus voltage < 0.95 pu. Then voltage control action is continued ***

- Action 3: select the most sensitive control measure

** V 200 : generator connected to bus 200 **

- controlled bus voltage = 0.79404 pu

- original setting at:

V schedule = 1.045 pu
V actual = 0.9864 pu

Because (V schedule > V actual). Therefore this controller is not suitable for adjusting.

*** controlled bus voltage < 0.95 pu. Then voltage control action is continued ***

- Action 4: select the most sensitive control measure

** D 1300 : switched capacitor connected to bus 1300 **

- controlled bus voltage = 0.79404 pu

- original setting at:

  Switched shunt = 0.0 MVAr
  Installed capacity = 20 MVAr

Because (switched shunt < installed capacity). Therefore this controller can be adjusted to.

- new setting at:

  Switched shunt = 20.0 MVAr

- controlled bus voltage = 0.88786 pu

*** controlled bus voltage < 0.95 pu. Then voltage control action is continued ***

- Action 5: select the most sensitive control measure

** V 800 : synchronous condenser connected to bus 800 **

- controlled bus voltage = 0.88786 pu

- original setting at:

  V schedule = 1.04 pu
  V actual = 0.94567 pu

Because (V schedule > V actual). Therefore this controller is not suitable for adjusting.

*** controlled bus voltage < 0.95 pu. Then voltage control action is continued ***

- Action 6: select the most sensitive control measure

** V 300 : synchronous condenser connected to bus 300 **

- controlled bus voltage = 0.88786 pu

- original setting at:

  V schedule = 1.01 pu
  V actual = 0.92193 pu

Because (V schedule > V actual). Therefore this controller is not suitable for adjusting.

*** controlled bus voltage < 0.95 pu. Then voltage control action is continued ***

- Action 7: select the most sensitive control measure

** D 900 : switched capacitor connected to bus 900 **

- controlled bus voltage = 0.88786 pu

- original setting at:

  Switched shunt = 0.0 MVAr
  Installed capacity = 20 MVAr

Because (switched shunt < installed capacity). Therefore this controller can be adjusted to.

- new setting at:

Switched shunt = 20.0 MVAr

- controlled bus voltage = 0.95417 pu

*** controlled bus voltage >= 0.95 pu. Hence, the low voltage problem at this controlled bus has been fixed ***

d) Task 2: voltage violation check

* Number of voltage violations : 4
* The problem severity is : major problem (No. violated buses >= 3)

Low voltage detection:

Bus number	Voltage (p.u)
500	0.90681
400	0.90915
1400	0.94626
1000	0.94731

* The worst problem is at bus 500. Therefore the most effective control is selected at bus 500.

c) Task 3: Voltage correction

Get the sensitivity tree for this controlled bus from the network sensitivity factors calculation for this outage:

Controlled bus: 500

Sensitivity factors	Control measures	Description
- 0.46227	V 200	Gen. connected to bus 200
- 0.19716	V 300	Syn. condenser connected to bus 300
- 0.19261	V 1600	Syn. condenser connected to bus 1600
0.13817	N 500-1500	Trans. connected between 500-1500
- 0.11824	V 800	Syn. condenser connected to bus 800
0.06846	N 400-700	Trans. connected between 400-700
0.03482	D 1300	S. capacitor connected to bus 1300
0.03083	D 900	S. capacitor connected to bus 900
0.02240	N 400-900	Trans. connected between 400-900
0.00000	V 100	Gen. connected to bus 100

- Action 1: select the most sensitive control measure

** V 200 : generator connected to bus 200 **

- controlled bus voltage = 0.90681 pu

- original setting at:

V schedule = 1.045 pu
V actual = 1.0089 pu

Because (V schedule > V actual). Therefore this controller is not suitable for adjusting.

*** controlled bus voltage < 0.95 pu. Then voltage control action is continued ***

- Action 2: select the most sensitive control measure

** V 300 : synchronous condenser connected to bus 300 **

- controlled bus voltage = 0.90681 pu

- original setting at:

V schedule = 1.01 pu
V actual = 0.94735 pu

Because (V schedule > V actual). Therefore this controller is not suitable for adjusting.

*** controlled bus voltage < 0.95 pu. Then voltage control action is continued ***

- Action 3: select the most sensitive control measure

** V 1600 : synchronous condenser connected to bus 1600 **

- controlled bus voltage = 0.90681 pu

- original setting at:

V schedule = 1.04 pu
V actual = 1.0399 pu

Because (V schedule > V actual). Therefore this controller is not suitable for adjusting.

*** controlled bus voltage < 0.95 pu. Then voltage control action is continued ***

- Action 4: select controller with the next highest sensitivity factor.

** N 500 - 1500 : transformer connected between buses 500-1500 **

- controlled bus voltage = 0.90681 pu

- original setting at:

Tap = 0.90075

This controller can not be adjusted. Because the voltage problem can not be solved by varrying this Tap.

*** controlled bus voltage < 0.95 pu. Then voltage control action is continued ***

- Action 5: select the most sensitive control measure

** V 800 : synchronous condenser connected to bus 800 **

- controlled bus voltage = 0.90681 pu

- original setting at:

V schedule = 1.04 pu
V actual = 1.00446 pu

Because (V schedule > V actual). Therefore this controller is not suitable for adjusting.

*** controlled bus voltage < 0.95 pu. Then voltage control action is continued ***

- Action 6: select controller with the next highest sensitivity factor.

** N 400 - 700 : transformer connected between buses 400-700 **

- controlled bus voltage = 0.90681 pu

- original setting at:

Tap = 0.978

Because (0.9 < Tap < 1.1). Therefore this controller tap can be adjusted to:

- New setting at:

Tap = 0.92175

- controlled bus voltage = 0.90753 pu

*** controlled bus voltage < 0.95 pu. Then voltage control action is continued ***

- Action 7: select the most sensitive control measure

** D 1300 : switched capacitor connected to bus 1300 **

- controlled bus voltage = 0.90753 pu

- original setting at:

Switched shunt = 20 MVAr
Installed capacity = 20 MVAr

Because (switched shunt = installed capacity). Therefore this controller can not be adjusted.

*** controlled bus voltage < 0.95 pu. Then voltage control action is continued ***

- Action 8: select the most sensitive control measure

** D 1300 : switched capacitor connected to bus 1300 **

- controlled bus voltage = 0.90753 pu

- original setting at:

Switched shunt = 20 MVAr
Installed capacity = 20 MVAr

Because (switched shunt = installed capacity). Therefore this controller can not be adjusted.

*** controlled bus voltage < 0.95 pu. Then voltage control action is continued ***

- Action 9: select controller with the next highest sensitivity factor.

** N 400 - 900 : transformer connected between buses 400-900 **

- controlled bus voltage = 0.90753 pu
- original setting at:

  Tap = 0.969

Because (0.9 < Tap < 1.1). Therefore this controller tap can be adjusted to:

- New setting at:

  Tap = 0.97525

- controlled bus voltage = 0.90772 pu

*** controlled bus voltage < 0.95 pu. Then voltage control action is continued ***

- Action 10: select the most sensitive control measure

** V 100 : generator connected to bus 100 **

- controlled bus voltage = 0.90772 pu
- original setting at:

  V schedule = 1.05 pu
  V actual = 1.05 pu

Because (V schedule = V actual) and (V schedule < 1.06 pu). Therefore this controller is suitable for further adjusting. But as a result from voltage correction estimation, by further adjusting this controller overvoltage problem will exist.

*** controlled bus voltage < 0.95 pu. Then voltage control action is continued ***

****
* All controllers have been used. The voltage problem still *
* exists. Hence, reactive power compensation is needed. *
****

(ii) REACTIVE POWER COMPENSATION (VAR support) STUDY

a) Low voltage detection:

Bus number	Voltage (p.u)
400	0.90843
500	0.90753

b) Calculate the sensitivity factors for capacitor bus selection

Capacitor bus	Sensitivity factors
400	0.12889
500	0.04296

c) Run number 1:

. Select the bus with highest sensitivity factor value.

Capacitor bus = 400

. Result of capacitor study:

Maximum bank size = 42 MVAr

Total capacitor required to be installed at bus 400 = 58 MVAr

. Bus voltages:

Low voltage bus number	Initial value (p.u)	Final value (p.u)
400	0.90843	0.94934
500	0.90753	0.93973

. Low voltage problem still exists. Hence, the VAR support study is continued.

c) Run number 2:

. Select the bus with the next highest sensitivity factor value.

Capacitor bus = 500

. Result of capacitor study:

Maximum bank size = 39 MVAr

Total capacitor required to be installed at bus 500 = 14 MVAr

. Bus voltages:

Low voltage bus number	Initial value (p.u)	Final value (p.u)
400	0.94934	0.95733
500	0.93973	0.95005

. The low voltage problem is fixed.

```
*******************************************************
*     There is no more volatge violation problem.       *
*                                                       *
*    The voltage/reactive power control & reactive power *
*           compensation study is completed.            *
*******************************************************
```

A summary on the volatge/ reactive power control and reactive power compensation study for the AEP network with the critical case of line 100-500 outage is shown in appendix C. Furthermore, to ensure that the VAR support of (58 + 14 =) 72 MVAr is good enough to overcome the voltage violation problem for all cases, the testings on voltage/reactive power control for all cases with additional 72 MVAr installed have been undertaken and their results are also shown in appendix C.

Table 6.1.2 shows the resulting voltage/ reactive power control and VAR support study. The system security margin requirements remain satisfied for all contingency cases.

Table 6.1.2: System security margin for the contingency cases

[After VAR allocation]

CASE No.	LINE OUTAGE	SM (%)
1	Base case (no outage)	23.97
2	100 - 200 (one of two lines)	19.12
3	100 - 500	10.64
4	200 - 400	13.29
5	600 - 1300	20.64
6	900 - 1400	21.83

6.2. NORTH-EAST TASMANIA SUBSYSTEM

As a power system becomes complicated and the number of voltage regulating facilities installed in the system increases, the voltage control problem tends to be more complex and more difficult to handle. For a large power system, the processing efficiency of the expert system would depend more on the size of the voltage problem rather than the system size. For higher efficiency, it is very useful to decompose a large power system into smaller subsystems by applying the Diakoptic algorithm, a wide-spread voltage problem is broken down into a number of smaller localized problems which will be suitable to apply the expert system for voltage control.

In order to demonstrate the effectiveness of the expert system applied to large power systems, the North-East Tasmania subsystem is decomposed from the large HEC power system for voltage/ reactive power control study.

The network one-line diagram and the network parameters of the North-East Tasmania subsystem are given in appendix C.

For this particularly network the base case and three contingency cases are considered. Table 6.2.1 shows the list of the contingencies and the computed security margin SM for each case, before taking VAR allocation, given by the expert system.

Table 6.2.1: System security margin for the contingency cases

[Before VAR allocation]

CASE No.	LINE OUTAGE	SM (%)
1	Base case (no outage)	53.40
2	100 - 300	20.39
3	100 - 400	35.91
4	300 - 500	50.10

The plot of load bus voltage variation against the increment of total MVA load of the subsystem with full configuration is shown in Figure 6.2.1.

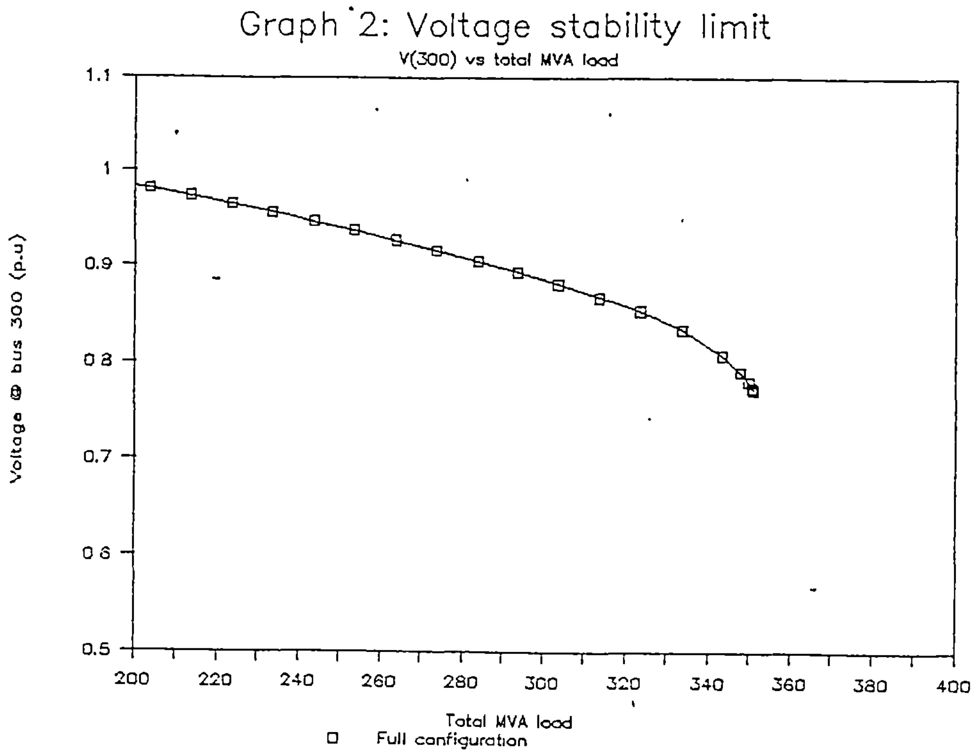


Figure 6.2.1: Voltage versus total MVA load at Bus 300.

As shown in Table 6.2.1, case 2 with SM of 20.39% is the most severe operating state and therefore selected for voltage/ reactive power control and VAR support study.

Detailed control actions for voltage/ reactive power control and VAR support problem solving by the expert system are recorded as follows.

(i). VOLTAGE/ REACTIVE POWER CONTROL

Contingency: Line 100 - 300 outage

a) Task 1: calculate the sensitivity factors for this sytem configuration and construct the sensitivity trees for all load buses.

b) Task 2: voltage violation check

* Number of voltage violations : 9
* The problem severity is : major problem (No. violated buses >= 3)

Low voltage detection:

Bus number	Voltage (p.u)
1000	0.80781
900	0.81346
800	0.82105
700	0.89097
300	0.89333
500	0.92080
1100	0.92299
600	0.93346
400	0.94420

* The worst problem is at bus 1000. Therefore the most effective control is selected at bus 1000.

c) Task 3: Voltage correction

Get the sensitivity tree for this controlled bus from the network sensitivity factors calculation for this outage:

Controlled bus: 1000

Sensitivity factors	Control measures	Description
- 0.92646	N 500-600	Trans. connected between 500-600
- 0.88050	N 300-700	Trans. connected between 300-700
- 0.54970	V 200	Gen. connected to bus 100
- 0.45954	V 100	Gen. connected to bus 200
- 0.43007	N 400-600	Trans. connected between 400-600

- Action 1: select the most sensitive control measure

** N 500 - 600 : transformer connected between buses 500-600 **

- controlled bus voltage = 0.80781 pu

- original setting at:

Tap = 1.0

Because (0.9 < Tap < 1.1). Therefore this controller tap can be adjusted to:

- New setting at:

Tap = 0.90625

- controlled bus voltage = 0.92797 pu

*** controlled bus voltage < 0.95 pu. Then voltage control action is continued ***

- Action 2: select the most sensitive control measure

** N 300 - 700 : transformer connected between buses 300-700 **

- controlled bus voltage = 0.92797 pu

- original setting at:
  Tap = 1.0

Because (0.9 < Tap < 1.1). Therefore this controller tap can be adjusted to:

- New setting at:
  Tap = 1.025

- controlled bus voltage = 0.95606 pu

*** controlled bus voltage >= 0.95 pu. Hence, the low voltage problem at this controlled bus has been fixed ***

d) Task 2: voltage violation check

* Number of voltage violations : 3
* The problem severity is : major problem (No. violated buses >= 3)

Low voltage detection:

Bus number	Voltage (p.u)
1100	0.92925
600	0.93972
400	0.94948

* The worst problem is at bus 1100. Therefore the most effective control is selected at bus 1100.

e) Task 3: Voltage correction

Get the sensitivity tree for this controlled bus from the network sensitivity factors calculation for this outage:

Controlled bus: 1100

Sensitivity factors	Control measures	Description
- 0.79092	V 200	Gen. connected to bus 100
- 0.23550	V 100	Gen. connected to bus 200
- 0.22039	N 400-600	Trans. connected between 400-600
0.00512	N 500-600	Trans. connected between 500-600
0.00082	N 300-700	Trans. connected between 300-700

- Action 1: select the most sensitive control measure

** V 200 : generator connected to bus 200 **

- controlled bus voltage = 0.92925 pu

- original setting at:
  V schedule = 1.055 pu
  V actual = 0.97985 pu

Because (V schedule > V actual). Therefore this controller is not suitable for adjusting.

*** controlled bus voltage < 0.95 pu. Then voltage control action is continued ***

- Action 2: select the most sensitive control measure

** V 100 : generator connected to bus 100 **

- controlled bus voltage = 0.92925 pu

- original setting at:

  V schedule = 1.0455 pu
  V actual = 1.0455 pu

Because (V schedule = V actual) and (V schedule < 1.06). Therefore this controller can be adjusted to:

- new setting at:

  V schedule = 1.05596 pu
  V actual = 1.05596 pu

- controlled bus voltage = 0.94288 pu

*** controlled bus voltage < 0.95 pu. Then voltage control action is continued ***

- Action 3: select the most sensitive control measure

** N 400 - 600 : transformer connected between buses 400-600 **

- controlled bus voltage = 0.94288 pu

- original setting at:

  Tap = 1.0

Because (0.9 < Tap < 1.1). Therefore this controller tap can be adjusted to:

- New setting at:

  Tap = 1.00625

- controlled bus voltage = 0.94955 pu

*** controlled bus voltage < 0.95 pu. Then voltage control action is continued ***

- Action 4: select the most sensitive control measure

** N 500 - 600 : transformer connected between buses 500-600 **

- controlled bus voltage = 0.94955 pu

- original setting at:

  Tap = 0.90625

Because (0.9 < Tap < 1.1), this controller tap can be adjusted to:

- New setting at:

  Tap = 0.9125

- controlled bus voltage = 0.95043 pu

*** controlled bus voltage >= 0.95 pu. Hence, the low voltage problem at this controlled bus has been fixed ***

f) Task 2: voltage violation check

* Number of voltage violations : 0
* The problem severity is : normal

```
**************************************************
*    All voltage problems have been fixed.        *
*  Reactive power compensation is not required    *
**************************************************
```

```
*******************************************************
*        There is no more volatge violation problem.        *
*                                                           *
*      The voltage/reactive power control & reactive power  *
*            compensation study is completed.               *
*******************************************************
```

A summary on the volatge/ reactive power control study for the North-East Tasmania subsystem with the critical case of line 100-300 outage is shown in appendix C. Furthermore, to ensure that there is no VAR support required to overcome the voltage violation problem for all cases, the testings on voltage/reactive power control for all cases have been undertaken and their results are also shown in appendix C.

Note that Table 6.2.1 shows the system security margin calculated for all cases without VAR support are greater than 10%, which means there would not be any VAR support required for this subsystem and it has been proved through the tests.

7. DISCUSSION AND FURTHER WORKS

DISCUSSION:

The following is the main features of the developed expert system:

-The input/output interface facilities gives a friendly user interface to the power system.

-The expert system for voltage and reactive power control can restore the system to desired limits even when the system is subjected to large disturbances.

-The expert system automatically tunes to the new system operating condition when the system operating configuration changes.

-The developed expert system has capability to solve voltage problem for power network which has less than 50 buses.

-The test results show the expert system performs the tasks well and very sactisfactory results:

* All bus voltages are within the specified limits.

* The network operating security level is increased.

* Reduction in total system losses, which means reduce the operating cost.

-There is a reduction in total system losses during voltage/ reactive power control. Therefore, the developed expert system can be used to find the new operating condition of the power network for the purpose as similar task as getting optimal load flow solution.

FURTHER WORK:

Although the expert system performs the task well, there is much scope for further development. There are a number of extensions to the expert system in order to reduce the execution time and to improve response in solving problems in large power systems. These extensions are:

- There is an advantage in selecting IPLAN language for building up the knowledge base. Because, as already stated, IPLAN is a programming language designed to be ultilized as a product to control the existing power flow application programs such as PSS/E. But there is also a disadvantage related on this selection. Because of limitations in IPLAN programs, (real variables = 4000 and integer variables = 4000), there is a limitation on power network size.

For power network which has more than 50 buses, the determination of the sensitivity S matrix (sensitivity factors) is difficult. The computing time required for the calculation of the S matrix would increase when the total number of buses increases. To overcome this problem the Diakoptic algorithm can be applied to decompose the power network into a number of smaller subsystems for voltage control.

However, for further development by applying the Triangular matrix factorization technique in the calculation of the S matrix, the reduction in computing time and the increment in network size can be achieved. Note that with the developed expert system it takes a few minutes to solve a voltage violation problem of a power network which has less than 50 buses, this executing time is quite acceptable compared to the real-time control time frame (in few minutes).

- Include the knowledge-based load shedding in the expert system. Note that in order to restore a normal voltage profile, when the existing control measures fail to restore the voltage profile, the reactive power dispatch such as VAR support and/or load shedding will be needed. Dropping loads may reduce the line flows and reactive power demands and hence the system voltage may be corrected, but the consumer's requirements must be taken into account.

8. CONCLUSION

Development of an expert system for voltage control and reactive power compensation has been successful. Based on the wide band of theories given in the first two chapters in this paper, a knowledge based system was developed and represented by a group of production rules, which control the execution of the power flow calculation and data manipulation through the expert system shell VP-EXPERT.

The developed expert system can be used to aid in the detection of voltage violation problems, and to restore the voltage profile by the suitable allocation of reactive power sources throughout the power system, ie., by adjusting transformer taps, changing generator voltages, and by switching reactive power compensators (VAR). The expert system also includes the evaluation of different locations and of the minimum VAR capacity that should be installed in the power system to improve system security and to reduce system losses.

The expert system was tested to establish its capability by using the standard test case (AEP 14-bus system) and the real case of Tasmania 's North-East part of the HEC transmission network. By applying the expert system of voltage/ reactive power control to the power networks and setting the contingency outages, the following new operating conditions are achieved :

- The voltage profiles are restored by reallocating the reactive power sources. This includes the evaluation on selection of locations and minimum VAR capacity that should be installed.

- All load bus voltages are controlled within the specified limits.

- The network operating security level is increased.

- Total system losses are reduced, with a consequent reduction of operating costs.

- Analytical results are expressed in natural language and hence are easy to understand.

The test shows that the expert system performs well and gives very satisfactory results. All goals for completion of the expert system have been achieved. The execution time measurements obtained through the test indicate that the expert system is feasible for on-line operation for problems which require response time in few minutes provided that the required control measurements are available.

The expert system can be successfully used to assist the system designers in transmission planning studies. It will not replace an expert, but it will support a technical specialist.

Further developments, such as including load shedding into the knowledge base of the expert system, can be made to enable the expert system to be used in system operation, particularly for the assessment of reactive reserve margin and for the improvment of voltage control, and to minimise system losses.

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APPENDIX A

Includes:

a) Format of switched capacitor bank data file

b)Format of power flow raw data file

a) SWITCHED CAPACITOR BANK DATA FILE (filename = SWITCHCP.DAT)

The input data is given by (bus number, total capacitor in MVAr installed, bank size). The data file format is as follows:

-Title: five lines of heading to be associated with the case. These lines should be started by an alphabet character (not a digit).

-Bus number: (1 to 99997), punched in columns 5-25 as an integer figure.

-Total capacitor installed: a real data type punched in columns 35-50.

-Bank size: a real data type punched in columns 60-75.

eg. SWITHCP.DAT

```
C
C       ****    SWITCHED CAPACITOR DATA    *****
Column
C 5 <----------------->25          35 <---------->50          60 <---------->75
C      BUS NUMBER                      TOTAL MVAr                     BANK SIZE

          200                             50.0                          10.0
         1400                             20.0                           4.0
```

b) POWER FLOW RAW DATA FILE

The bulk power flow input data consists of twelve groups of records, with each group cointaining a particular type of data required in power flow work (see Figure 4.1.1).

4.1.1.1 Case Identification Data

Case identification data consists of three data records. The first record contains two items of data as follows:

IC, SBASE

where:

IC = change code: 0 for base case, 1 to add data to the working case.

SBASE = system base MVA.

NOTE: Both values must be entered.

The next two records each contain a line of heading to be associated with the case. Each line may contain up to sixty characters which are typed in columns one through sixty.

4.1.1.2 Bus Data

Each network bus to be represented in PSS/E is introduced by reading a bus data record. Each bus data record has the following format:

I, IDE, PL, QL, GL, BL, IA, VM, VA, 'NAME', BASKV, ZONE

where:

I = bus number (1 to 99997).

IDE = bus type code:
1 - load bus (no generation)
2 - generator or plant bus (either voltage regulating or fixed MVAR)
3 - swing bus
4 - isolated bus

IDE = 1 by default.

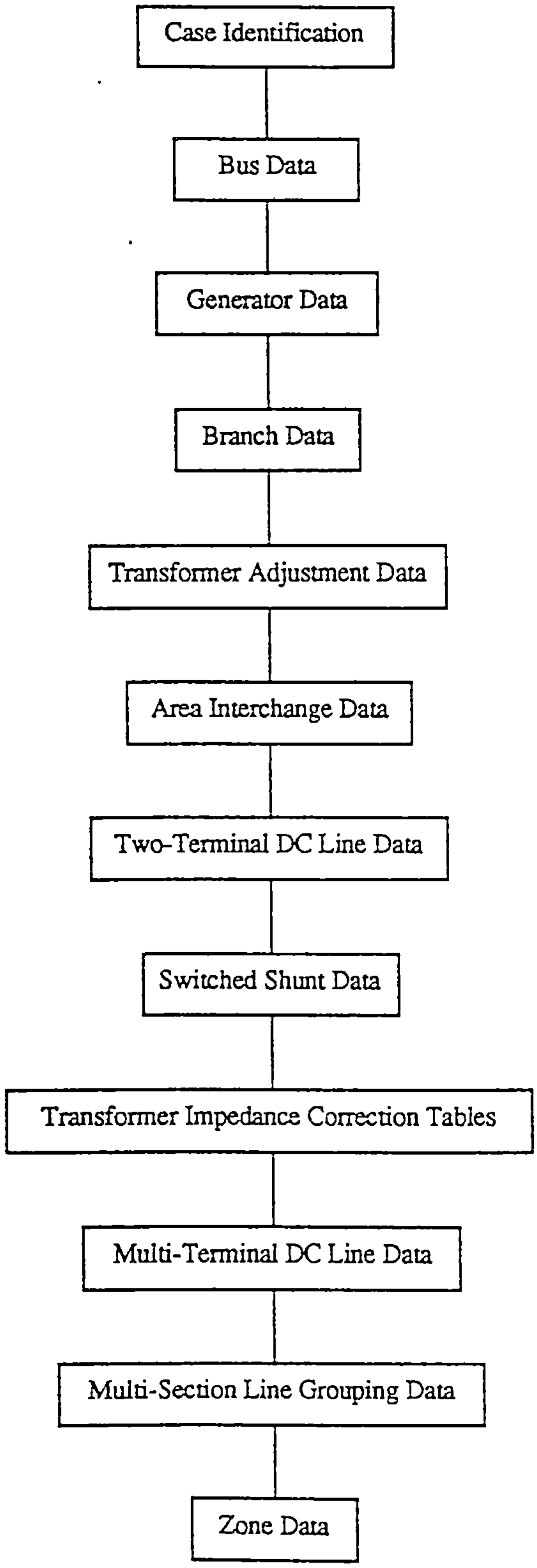


FIGURE 4.1.1

Power Flow Raw Data Input Structure

PL = load real power to be held constant; entered in MW. PL = 0. by default.

QL = load reactive power to be held constant; entered in MVAR. QL = 0. by default.

GL = real component of shunt admittance to ground, including resistive impedance load; entered in MW at unity voltage. GL = 0. by default.

BL = reactive component of shunt admittance to ground, including reactive impedance load, but excluding line charging and any line connected shunts which are entered as part of the branch data; entered in MVAR at unity voltage. BL is a negative quantity for an inductive load. BL = 0. by default.

IA = area number (1 to 100). IA = 1 by default.

VM = bus voltage magnitude; entered in p.u. VM = 1. by default.

VA = bus voltage phase angle; entered in degrees. VA = 0. by default.

NAME = alphanumeric identifier assigned to bus "I". The name may be up to eight characters and must be enclosed in single quotes. NAME may contain any combination of blanks, upper case letters, numbers and special characters. NAME is eight blanks by default.

BASKV = bus base voltage; entered in kV. BASKV = 0. by default.

ZONE = zone (1 to 999). ZONE = 1 by default.

VM and VA need to be set to their actual solved case values only when the network, as entered into the working case via activity READ, is to be considered solved as read in. Otherwise, they may be set to their default values.

Bus data input is terminated with a record specifying a bus number of zero.

4.1.1.3 Generator Data

Each network bus which is to be represented as a generator or plant bus in PSS/E must be specified in a generator data record. In particular, each bus which is specified in the bus data input with a type code of two or three must have a generator data record entered for it. Each generator data record has the following format:

```
I,ID,PG,QG,QT,QB,VS,IREG,MBASE,ZR,ZX,RT,XT,GTAP,STAT,RMPCT,PT,PB
```

where:

I = bus number (1 to 99997).

ID = single character machine identifier (0 through 9 or A through Z) which is used to distinguish among multiple machines at bus "I"; ID = 1 by default.

PG = generator real power output; entered in MW. PG = 0. by default.

QG = generator reactive power output; entered in MVAR. QG need be entered only if the case, as read in, is to be treated as a solved case. QG = 0. by default.

QT = maximum generator reactive power output; entered in MVAR. For fixed output generators (i.e., non-regulating), QT must be equal to the fixed MVAR output. QT = 9999. by default.

QB = minimum generator reactive power output; entered in MVAR. For fixed output generators, QB must be equal to the fixed MVAR output. QB = -9999. by default.

VS = regulated voltage setpoint; entered in p.u. VS = 1. by default.

IREG = bus number of a remote type one bus whose voltage is to be regulated by this plant to the value specified by VS. IREG is entered as zero if the plant is to regulate its own voltage and must be zero for a type three (swing) bus. IREG = 0 by default.

MBASE = total MVA base of the units represented by this machine; entered in MVA. This quantity is not needed in normal power flow and equivalent construction work, but is required for switching studies, fault analysis and dynamic simulation. MBASE = system base MVA by default.

ZR,ZX = machine impedance, ZSORCE; entered in p.u. on MBASE base. This data is not needed in normal load flow and equivalent construction work, but is required for switching studies, fault analysis and dynamic simulation. For dynamic simulation, this complex impedance must be set equal to the subtransient impedance for those generators which are to be modeled by subtransient level machine models, and to transient impedance for those to be modeled by classical or transient level models. ZR = 0. and ZX = 1. by default.

RT,XT = step-up transformer impedance, XTRAN; entered in p.u. on MBASE base. RT + jXT = 0. by default.

GTAP = step-up transformer off-nominal turns ratio; entered in p.u. GTAP = 1. by default.

STAT = initial machine status of one for in-service and zero for out-of-service; STAT = 1 by default.

RMPCT = percent of the total MVARs required to hold the voltage at bus IREG that are to be contributed by the generation at bus I. RMPCT is needed only if IREG specifies a remote type one bus and there is more than one generator bus controlling the voltage at bus IREG. RMPCT = 100 by default.

PT = maximum generator real power output; entered in MW. PT = 9999. by default.

PB = minimum generator real power output; entered in MW. PB = -9999. by default.

When two or more machines are to be separately modeled at a plant, their data may be introduced into the working case using one of two approaches.

A generator data record may be entered in activity READ, TREA or RDCH for each of the machines to be represented, with machine powers, power limits, impedance data, and step-up transformer data for each machine specified on separate generator data records. The plant power output and power limits are taken as the sum of the corresponding quantities of the in-service machines at the plant. The values specified for VS, IREG and RMPCT, which are treated as plant quantities rather than individual machine quantities, must be identical on each of these generator data records.

Alternatively, a single generator record may be specified in activity READ, TREA or RDCH with the plant total power output, power limits, voltage setpoint, remotely regulated bus, and percent of contributed MVARs entered. Impedance and step-up transformer data may be omitted. The PSS/E power flow activities may be used and then, any time prior to beginning switching study, fault analysis or dynamic simulation work, activity MCRE may be used to introduce the individual machine impedance and step-up transformer data; activity MCRE also apportions the total plant loading among the individual machines (see Section 4.4).

Generator data input is terminated with a record specifying a bus number of zero.

4.1.1.4 Branch Data

Each AC network branch to be represented in PSS/E is introduced by reading a branch data record. Each branch data record has the following format:

```
I,J,CKT,R,X,B,RATEA,RATEB,RATEC,RATIO,ANGLE,GI,BI,GJ,BJ,ST
```

where:

I	=	branch "from bus" number. For a transformer, this bus is the tapped side bus.
J	=	branch "to bus" number. For a transformer, this bus is the impedance side bus. J is entered as a negative number to designate it as the metered end; otherwise, bus I is assumed to be the metered end.
CKT	=	two character upper case alphanumeric branch circuit identifier; the first character of CKT must <u>not</u> be an ampersand ("&", see Section 4.1.1.11). It is strongly recommended that single circuit branches be designated as having the circuit identifier "1". CKT = 1 by default.
R	=	branch resistance; entered in p.u. A value of R must be entered for each branch.
X	=	branch reactance; entered in p.u. A non-zero value of X must be entered for each branch. See Section 4.1.4 for details on the treatment of branches as zero impedance lines.
B	=	total branch charging susceptance; entered in p.u. B = 0. by default.
RATEA	=	first current rating; entered in MVA. RATEA = 0. (bypass check for this branch) by default. See also Section 4.53.
RATEB	=	second current rating; entered in MVA. RATEB = 0. by default.
RATEC	=	third current rating; entered in MVA. RATEC = 0. by default.
RATIO	=	transformer off-nominal turns ratio; entered in p.u. RATIO is entered as zero if the branch is not a transformer. RATIO = 0. by default.
ANGLE	=	transformer phase shift angle; entered in degrees. Ignored unless RATIO is entered as a non-zero value. ANGLE is positive for a positive phase shift from the untapped to the tapped side. ANGLE = 0. by default.

GI,BI = complex admittance of the line shunt at the bus "I" end of the branch; entered in p.u. BI is negative for a line connected reactor. GI + jBI = 0. by default.

GJ,BJ = complex admittance of the line shunt at the bus "J" end of the branch; entered in p.u. BJ is negative for a line connected reactor. GJ + jBJ = 0. by default.

ST = initial branch status where one designates in-service and zero designates out-of-service. ST = 1 by default.

Branch data input is terminated with a record specifying a from bus number of zero.

4.1.1.5 Transformer Adjustment Data

Control parameters for the automatic adjustment of transformers and phase shifters are specified in the transformer adjustment data records. Only branches which are designated as transformers (i.e., branches input with a non-zero value of RATIO), may be specified in a transformer adjustment data record. All transformers are adjustable and the control parameters may be specified either at the time of raw data input or subsequently via activity CHNG. Any transformer for which no control data is provided will have default data assigned to it; the default data is such that the transformer will be treated as a fixed tap transformer.

Each transformer adjustment data record has the following format:

```
I, J, CKT, ICONT, RMA, RMI, VMA, VMI, STEP, TABLE, CNTRL
```

where:

I = "from bus" number

J = "to bus" number

CKT = circuit identifier; the branch described by I, J and CKT must have been entered in a branch data record with a non-zero value of RATIO specified.

ICONT = number of the bus whose voltage is to be controlled by the transformer turns ratio adjustment option of the power flow solution activities. ICONT should be non-zero only for voltage controlling transformers.

ICONT may be the number of a bus other than I and J; in this case, the sign of ICONT defines the location of the controlled bus relative to the transformer. If ICONT is entered as a positive number, the ratio will be adjusted as if bus ICONT is on the untapped (impedance) side of the transformer; if ICONT is entered as a negative number, the ratio will be adjusted as if bus ICONT is on the tapped side of the transformer. ICONT = 0 by default.

RMA = upper limit of either:

a) off-nominal ratio for voltage or MVAR controlling transformers, entered in p.u.; or

b) phase shift angle for MW controlling transformers, entered in degrees.

RMA = 1.5 by default.

RMI = lower limit of either:

a) off-nominal ratio for voltage or MVAR controlling transformers, entered in p.u.; or

b) phase shift angle for MW controlling transformers, entered in degrees.

RMI = 0.51 by default.

VMA = upper limit of either:

a) controlled bus voltage, entered in p.u.; or

b) real power flow through the phase shifter, calculated at the tapped side bus, entered in MW; or

c) reactive power flow through the transformer, calculated at the tapped side bus, entered in MVAR.

VMA = 1.5 by default.

VMI = lower limit of either:

a) controlled bus voltage, entered in p.u.; or

b) real power flow through the phase shifter, calculated at the tapped side bus, entered in MW; or

c) reactive power flow through the transformer, calculated at the tapped side bus, entered in MVAR.

VMI = 0.51 by default.

STEP = transformer turns ratio step increment; ignored for phase shifters controlling real power flow. STEP = 0.00625 by default.

TABLE = zero, or the number of a transformer impedance correction table (1 through 9) if this transformer's impedance is to be a function of either off-nominal turns ratio or phase shift angle (see Section 4.1.1.9). TABLE = 0 by default.

CNTRL = adjustment enable flag; one to enable automatic adjustment by this transformer as specified by its adjustment data values when that adjustment is activated during power flow solutions; zero to prohibit the automatic adjustment of this transformer. CNTRL = 1 by default.

Table 4.1.1 summarizes the interpretation of these data items when they are used by the automatic adjustment options of the power flow solution activities. See Section 4.10.3 for further discussion.

Transformer adjustment data input is terminated with a record specifying a from bus number of zero.

TABLE 4.1.1

Transformer Adjustment Data

	ICONT	RMA, RMI	RMA-RMI	VMA, VMI	VMA-VMI	STEP
Discrete Ratio/Voltage	controlled bus	ratio limits	≤ 0.9 > 0.	voltage limits	≤ 0.9 > 0.	> 0.
Direct Ratio/Voltage	controlled bus	ratio limits	≤ 0.9 > 0.	voltage limits	≤ 0.9 > 0.	≥ 0.
Direct Ratio/MVAR	ignored	ratio limits	≤ 0.9 > 0.	MVAR limits	> 1.0	≥ 0.
Direct Angle/MW	ignored	angle limits	> 1.0	MW limits	> 0.0	ignored

4.1.1.6 Area Interchange Data

Area identifiers and interchange control parameters are specified in area interchange data records. Data for each interchange area may be specified either at the time of raw data input or subsequently via activity CHNG. Each area interchange data record has the following format:

```
I, ISW, PDES, PTOL, 'ARNAM'
```

where:

I = area number (1 to 100).

ISW = number of the area slack bus for area interchange control. The bus must be a generator (type two) bus in the specified area. Any area containing a system swing bus (type three) must have either that swing bus or a bus number of zero specified for its area slack bus number. Any area with an area slack bus number of zero is considered a "floating area" by the area interchange control option of the power flow solution activities. ISW = 0 by default.

PDES = desired net interchange leaving the area (export); entered in MW. PDES = 0. by default.

PTOL = interchange tolerance band width; entered in MW. PTOL = 10. by default.

ARNAM = alphanumeric identifier assigned to area I. The name may contain up to eight characters and must be enclosed in single quotes. ARNAM may be any combination of blanks, upper case letters, numbers and special characters. ARNAM is set to eight blanks by default.

Refer to Section 4.10.3 for further discussion on the area interchange control option of the power flow solution activities.

Area interchange data input is terminated with a record specifying an area number of zero.

4.1.1.7 Two-Terminal DC Transmission Line Data

Each two-terminal DC transmission line to be represented in PSS/E is introduced by reading three consecutive data records. Each set of DC line data records has the following format:

```
I, MDC, RDC, SETVL, VSCHD, VCMOD, RCOMP, DELTI, METER, DCVMIN
IPR,NBR,ALFMX,ALFMN,RCR,XCR,EBASR,TRR,TAPR,TMXR,TMNR,STPR,ICR,IFR,ITR,IDR
IPI,NBI,GAMMX,GAMMN,RCI,XCI,EBASI,TRI,TAPI,TMXI,TMNI,STPI,ICI,IFI,ITI,IDI
```

where:

I	=	DC line number (1 to 20).
MDC	=	control mode: 0 for blocked, 1 for power, 2 for current. MDC = 0 by default.
RDC	=	DC line resistance; entered in ohms. No default allowed.
SETVL	=	current (amps) or power (MW) demand. When MDC is one, a positive value of SETVL specifies desired power at the rectifier and a negative value specifies desired inverter power. No default allowed.
VSCHD	=	scheduled compounded DC voltage; entered in kV. No default allowed.
VCMOD	=	mode switch DC voltage; entered in kV. When the inverter DC voltage falls below this value and the line is in power control mode (i.e., MDC = 1), the line switches to current control mode with a desired current corresponding to the desired power at scheduled DC voltage. VCMOD = 0. by default.
RCOMP	=	compounding resistance; entered in ohms. Gamma and/or TAPI will be used to attempt to hold the compounded voltage (VDCI + DCCUR*RCOMP) at VSCHD. To control the inverter end DC voltage VDCI, set RCOMP to zero; to control the rectifier end DC voltage VDCR, set RCOMP to the DC line resistance, RDC; otherwise set RCOMP to the appropriate fraction of RDC. RCOMP = 0. by default.
DELTI	=	margin entered in per unit of desired DC power or current. This is the fraction by which the order is reduced when ALPHA is at its minimum and the inverter is controlling the line current. DELTI = 0. by default.
METER	=	metered end code of either 'R' (for rectifier) or 'I' (for inverter). METER = 'I' by default.
DCVMIN	=	minimum compounded DC voltage; entered in kV. Only used in constant gamma operation (i.e., when GAMMX = GAMMN) when TAPI is held constant and an AC transformer tap is adjusted to control DC voltage (i.e., when IFI, ITI and IDI specify a transformer branch). DCVMIN = 0. by default.
IPR	=	rectifier converter bus number. No default allowed.
NBR	=	number of bridges in series (rectifier). No default allowed.
ALFMX	=	nominal maximum rectifier firing angle; entered in degrees. No default allowed.
ALFMN	=	minimum steady state rectifier firing angle; entered in degrees. No default allowed.

RCR	=	rectifier commutating transformer resistance per bridge; entered in ohms. No default allowed.
XCR	=	rectifier commutating transformer reactance per bridge; entered in ohms. No default allowed.
EBASR	=	rectifier primary base AC voltage; entered in kV. No default allowed.
TRR	=	rectifier transformer ratio. No default allowed.
TAPR	=	rectifier tap setting. No default allowed.
TMXR	=	maximum rectifier tap setting. TMXR = 1.5 by default.
TMNR	=	minimum rectifier tap setting. TMNR = 0.51 by default.
STPR	=	rectifier tap step. STPR = 0.00625 by default.
ICR	=	rectifier firing angle measuring bus. The firing angle and angle limits used inside the DC model are adjusted by the difference between the phase angles at this bus and the AC/DC interface (i.e., the converter bus, IPR). ICR = 0 by default.
IFR	=	tapped side "from bus" number of an AC transformer branch. IFR = 0 by default.
ITR	=	untapped side "to bus" number of an AC transformer branch. ITR = 0 by default.
IDR	=	circuit identifier; the branch described by IFR, ITR and IDR must have been entered as a transformer branch. IDR = '1' by default.

If no branch is specified, TAPR is adjusted to keep alpha within limits; otherwise, TAPR is held fixed and this transformer's tap ratio is adjusted. The adjustment logic assumes that the rectifier converter bus is on the untapped side of the transformer. The limits TMXR and TMNR specified here are used; except for the transformer adjustment enable flag (see Section 4.1.1.5), the AC tap adjustment data is ignored.

Data on the third record contains the inverter quantities corresponding to the rectifier quantities on the second record described above.

DC line converter buses, IPR and IPI, may be type one, two or three buses. While generators and shunt elements are permitted at converter buses, they may not have any constant MVA load represented.

DC line data input is terminated with a record specifying a DC line number of zero.

4.1.1.8 Switched Shunt Data

Each network bus which is to be represented in PSS/E with switched shunt admittance devices must have a switched shunt data record specified for it. The switched shunts are represented with up to eight blocks of admittance, each one of which consists of up to nine steps of the specified block admittance. Each switched shunt data record has the following format:

$$I,\ MODSW,\ VSWHI,\ VSWLO,\ SWREM,\ BINIT,\ N_1,\ B_1,\ N_2,\ B_2,\ \ldots\ N_8,\ B_8$$

where:

I = bus number (1 to 99997).

MODSW = control mode: 0 for fixed, 1 for discrete, 2 for continuous. MODSW = 1 by default.

VSWHI = desired voltage upper limit; entered in p.u. VSWHI = 1. by default.

VSWLO = desired voltage lower limit; entered in p.u. VSWLO = 1. by default.

SWREM = bus number of a remote type one bus whose voltage is to be regulated by this switched shunt to the voltage range specified by VSWHI and VSWLO. SWREM is entered as zero if the device is to regulate its own voltage. SWREM = 0 by default.

BINIT = initial switched shunt admittance; entered in MVAR at unity voltage. BINIT = 0. by default.

N_i = number of steps for block i. The first zero value of N_i is interpreted as the end of the switched shunt blocks for bus I. N_i = 0 by default.

B_i = admittance increment for each of N_i steps in block i; entered in MVAR at unity voltage. B_i = 0. by default.

BINIT needs to be set to its actual solved case value only when the network, as entered into the working case via activity READ, is to be considered solved as read in, or when the device is to be treated as "fixed" (i.e., MODSW is set to zero or switched shunts are to be locked during power flow solutions).

The switched shunt elements at a bus may consist entirely of reactors (each B_i is a negative quantity) or entirely of capacitor banks (each B_i is a positive quantity). In these cases, the shunt blocks are specified in the order in which they are switched on the bus.

If the switched shunt devices at a bus are a mixture of reactors and capacitors, the reactor blocks are specified first in the order in which they are switched on, followed by the capacitor blocks in the order in which they are switched on.

The switched shunt admittance is kept in the working case and reported in output tabulations separately from the bus shunt, which is input on the bus data record.

Refer to Section 4.8.3 for details on the handling of switched shunts during the power flow solution activities.

Switched shunt data input is terminated with a record specifying a bus number of zero.

4.1.1.9 Transformer Impedance Correction Tables

Transformer impedance correction tables are used to model a change of transformer impedance as off-nominal turns ratio or phase shift angle is adjusted. Data for each table may be specified either at the time of raw data input or subsequently via activity CHNG. Each transformer impedance correction data record has the following format:

$$I, T_1, F_1, T_2, F_2, T_3, F_3, \ldots T_{11}, F_{11}$$

where:

I = impedance correction table number (1 to 9).

T_i = either off-nominal turns ratio in p.u. or phase shift angle in degrees. T_i = 0. by default.

F_i = scaling factor by which transformer nominal impedance is to be multiplied to obtain the actual transformer impedance for the corresponding "T_i". F_i = 0. by default.

The "T's" on each record must all be either tap ratios or phase shift angles. They must be entered in strictly ascending order; i.e., for each "i", $T_{i+1}>T_i$. Each "Fi" entered must be greater than zero. On each record, at least two pairs of values must be specified and up to eleven may be entered.

A transformer is assigned to an impedance correction table either on the transformer adjustment data record of activity READ, TREA or RDCH (see Section 4.1.1.5) or via activity CHNG. Each table may be shared among many transformers. If the first "T" in a table is less than 0.5 or the last "T" entered is greater than 1.5, the "T's" are assumed to be phase shift angles and the impedance of each transformer assigned to the table is treated as a function of phase shift angle. Otherwise, the impedances of the transformers assigned to the table are made sensitive to off-nominal turns ratio.

The working case provides for the storage of both a nominal and actual impedance for each transformer. The value of transformer impedance entered in activities READ, TREA, RDCH and CHNG is taken as the nominal value of impedance. Each time the complex tap ratio of a transformer is changed, either automatically by the power flow solution activities or manually by the user, and the transformer has been assigned to an impedance correction table, actual transformer impedance is re-determined if appropriate. First, the scaling factor is established from the appropriate table by linear interpolation; then nominal impedance is multiplied by the scaling factor to determine actual impedance. An appropriate message is printed any time the actual impedance is modified.

Transformer impedance correction data input is terminated with a record specifying a table number of zero.

4.1.1.10 Multi-Terminal DC Transmission Line Data

Each multi-terminal DC transmission line to be represented in PSS/E is introduced by reading a series of data records. Each set of multi-terminal DC line data records begins with a record of the following format:

```
I, NCONV, NDCBS, NDCLN, MDC, VCONV, VCMOD, VCONVN
```

where:

I = multi-terminal DC line number (1 to 5).

NCONV = number of AC converter station buses in multi-terminal DC line "I" (3 to 12). No default allowed.

NDCBS = number of "DC buses" in multi-terminal DC line "I" (NCONV ≤ NDCBS ≤ 20). No default allowed.

NDCLN = number of DC links in multi-terminal DC line "I" (2 to 20). No default allowed.

MDC = control mode: 0 for blocked, 1 for power, 2 for current. MDC = 0 by default.

VCONV = bus number of the AC converter station bus which controls DC voltage on the positive pole of multi-terminal DC line "I". Bus VCONV must be a positive pole inverter. No default allowed.

VCMOD = mode switch DC voltage; entered in kV. When any inverter DC voltage magnitude falls below this value and the line is in power control mode (i.e., MDC = 1), the line switches to current control mode with converter current setpoints corresponding to their desired powers at scheduled DC voltage. VCMOD = 0. by default.

VCONVN = bus number of the AC converter station bus which controls DC voltage on the negative pole of multi-terminal DC line "I". If any negative pole converters are specified (see below), bus VCONVN must be a negative pole inverter. If the negative pole is not being modeled, VCONVN must be specified as zero. VCONVN = 0 by default.

This data record is followed by "NCONV" converter records of the following format:

```
IB,N,ANGMX,ANGMN,RC,XC,EBAS,TR,TAP,TPMX,TPMN,TSTP,SETVL,DCPF,MARG,CNVCOD
```

where:

IB = AC converter bus number. No default allowed.

N = number of bridges in series. No default allowed.

ANGMX = nominal maximum ALPHA or GAMMA angle; entered in degrees. No default allowed.

ANGMN = minimum steady state ALPHA or GAMMA angle; entered in degrees. No default allowed.

RC = commutating resistance per bridge; entered in ohms. No default allowed.

XC = commutating reactance per bridge; entered in ohms. No default allowed.

EBAS = primary base AC voltage; entered in kV. No default allowed.

TR = actual transformer ratio. No default allowed.

TAP = tap setting. TAP = 1.0 by default.

TPMX = maximum tap setting. TPMX = 1.5 by default.

TPMN = minimum tap setting. TPMN = 0.51 by default.

TSTP = tap step. TSTP = 0.00625 by default.

SETVL = converter setpoint. When IB is equal to VCONV or VCONVN, SETVL specifies the scheduled DC voltage magnitude, entered in kV, across the converter. For other converter buses, SETVL contains the converter current (amps) or power (MW) demand; a positive value of SETVL indicates that bus IB is a rectifier and a negative value indicates an inverter. No default allowed.

DCPF = converter "participation factor." When the order at any rectifier in the multi-terminal DC line is reduced, either to maximum current or margin, the orders at the remaining converters on the same pole are modified according to their DCPF's to:

```
SETVL + (DCPF/SUM)*R
```

where SUM is the sum of the DCPF's at the unconstrained converters on the same pole as the constrained rectifier and R is the order reduction at the constrained rectifier. DCPF = 1. by default.

MARG = rectifier margin entered in per unit of desired DC power or current. The converter order reduced by this fraction, (1.-MARG)*SETVL, defines the minimum order for this rectifier. MARG is used only at rectifiers. MARG = 0. by default.

CNVCOD = converter code. A positive value or zero must be entered if the converter is on the positive pole of multi-terminal DC line "I". A negative value must be entered for negative pole converters. CNVCOD = 1 by default.

These data records are followed by "NDCBS" DC bus records of the following format:

```
IDC, IB, IA, ZONE, 'NAME', IDC2, RGRND
```

where:

IDC = DC bus number (1 to NDCBS). DC buses are used internally within each multi-terminal DC line and must be numbered one through NDCBS. No default allowed.

IB = AC converter bus number, or zero. Each converter station bus specified in a converter record must be specified as IB in exactly one DC bus record. DC buses which are connected only to other DC buses by DC links and not to any AC converter buses must have a zero specified for IB. A DC bus which is specified as IDC2 on one or more other DC bus records must have a zero specified for IB on its own DC bus record. IB = 0 by default.

IA = area number (1 to 100). IA = 1 by default.

ZONE = zone (1 to 999). ZONE = 1 by default.

NAME = alphanumeric identifier assigned to DC bus "IDC". The name may be up to eight characters and must be enclosed in single quotes. NAME may contain any combination of blanks, upper case letters, numbers and special characters. NAME is eight blanks by default.

IDC2 = second DC bus to which converter IB is connected, or zero if the converter is connected directly to ground. For voltage controlling converters, this is the DC bus with the lower DC voltage magnitude and SETVL specifies the voltage difference between buses IDC and IDC2. For rectifiers, DC buses should be specified such that power flows from bus IDC2 to bus IDC. For inverters, DC buses should be specified such that power flows from bus IDC to bus IDC2. IDC2 is ignored on those DC bus records which have IB specified as zero. IDC2 = 0 by default.

RGRND = resistance to ground at DC bus IDC; entered in ohms. During solutions RGRND is used only for those DC buses which were specified as IDC2 on other DC bus records. RGRND = 0. by default.

These data records are followed by "NDCLN" DC link records of the following format:

```
IDC, JDC, DCCKT, RDC, LDC
```

where:

IDC	=	branch "from bus" DC bus number.
JDC	=	branch "to bus" DC bus number. JDC is entered as a negative number to designate it as the metered end for area interchange and zone calculations. Otherwise, bus IDC is assumed to be the metered end.
DCCKT	=	one character upper case alphanumeric branch circuit identifier. It is strongly recommended that single circuit branches be designated as having the circuit identifier "1". DCCKT = 1 by default.
RDC	=	DC link resistance; entered in ohms. No default allowed.
LDC	=	DC link inductance, entered in millihenries. LDC is not used by the power flow solution activities but is available to multi-terminal DC line dynamics models. LDC = 0. by default.

The following points should be noted in specifying multi-terminal DC line data:

1) Two-terminal (see Section 4.1.1.7) and multi-terminal DC lines are stored separately in PSS/E working memory. Therefore, there may simultaneously exist, for example, a two-terminal DC line identified as DC line number one along with a multi-terminal line numbered one.

2) Multi-terminal lines should have at least three converter terminals; DC lines consisting of two terminals should be modeled as two-terminal lines (see Section 4.1.1.7).

3) AC converter buses may be type one, two or three buses. While generators and shunt elements are permitted at converter buses, they may not have any constant MVA load represented.

4) Each multi-terminal DC line is treated as a sub-network of "DC buses" connecting its AC converter buses. For each multi-terminal DC line, the DC buses must be numbered one through NDCBS.

5) Each AC converter bus must be specified as IB on one and only one DC bus record; there may be DC buses which are connected only to other DC buses by DC links but not to any AC converter bus.

6) An AC converter bus "IB" may be connected to a DC bus "IDC" which is connected directly to ground. "IB" is specified on the DC bus record for DC bus "IDC"; the IDC2 field is specified as zero.

7) Alternatively, an AC converter bus "IB" may be connected to two DC buses "IDC" and "IDC2", the second of which is connected to ground through a specified resistance. "IB" and "IDC2" are specified on the DC bus record for DC bus "IDC"; on the DC bus record for bus "IDC2", the AC converter bus and second DC bus fields (IB and IDC2 respectively) must be specified as zero and the grounding resistance is specified as RGRND.

8) The same DC bus may be specified as the second DC bus for more than one AC converter bus.

9) All DC buses within a multi-terminal DC line must be reachable from any other point within the subnetwork.

10) The area number assigned to DC buses and the metered end designation of DC links are used in calculating area interchange and assigning losses in activities AREA, INTA, TIES and SUBS as well

11) as in the interchange control option of the power flow solution activities. Similarly, the zone assignment and metered end specification is used in activities ZONE, INTZ, TIEZ and SUBS.

Multi-terminal DC line data input is terminated with a record specifying a DC line number of zero.

4.1.1.11 Multi-Section Line Grouping Data

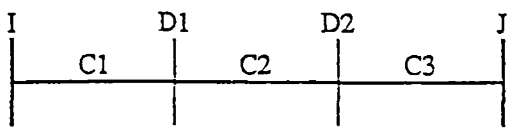
Each multi-section line grouping to be represented in PSS/E is introduced by reading a multi-section line grouping data record. Each multi-section line grouping data record has the following format:

$$I,\ J,\ ID,\ CKT_1,\ DUM_1,\ CKT_2,\ DUM_2,\ \ldots\ CKT_9,\ DUM_9,\ CKT_{10}$$

where:

I	=	"from bus" number.
J	=	"to bus" number. J is entered as a negative number to designate it as the meterd end; otherwise, bus I is assumed to be the metered end.
ID	=	two character multi-section line grouping identifier. The first character must be an ampersand ("&"). ID = '&1' by default.
CKT_i	=	branch circuit identifiers of branches which are members of this multi-section line grouping. CKT_i = '1' by default.
DUM_i	=	bus numbers of the "dummy buses" connected by the branches which comprise this multi-section line grouping. No defaults allowed.

The "CKT's" and "DUM's" on each record define the branches connecting bus I to bus J, and are entered so as to trace the path from bus I to bus J. Specifically, for a multi-section line grouping consisting of three "line sections" (and hence two "dummy buses"):



The path from "I" to "J" is defined by the following branches:

FROM	TO	CIRCUIT
I	D1	C1
D1	D2	C2
D2	J	C3

If this multi-section line grouping is to be assigned the line identifier "&1", the corresponding multi-section line grouping data record is given by:

```
I   J   &1   C1   D1   C2   D2   C3
```

Up to ten line sections (and hence nine dummy buses) may be defined in each multi-section line grouping.

Each dummy bus must have exactly two branches connected to it, both of which must be members of the same multi-section line grouping. A branch can be a line section of at most one multi-section line grouping.

The status of line sections and type codes of dummy buses are set such that the multi-section line is treated as a single entity with regards to its service status.

4.1.1.12 Zone Data

Zone identifiers are specified in zone data records. Data for each zone may be specified either at the time of raw data input or subsequently via activity CHNG. Each zone data record has the following format:

```
I, 'ZONAM'
```

where:

I = zone number (1 to 999).

ZONAM = alphanumeric identifier assigned to zone I. The name may contain up to eight characters and must be enclosed in single quotes. ZONAM may be any combination of blanks, upper case letters, numbers and special characters. ZONAM is set to eight blanks by default.

Zone data input is terminated with a record specifying a zone number of zero.

APPENDIX B

EXPERT SYSTEM RUNNING INSTRUCTIONS

This section provides users with a set of quick and easy instructions for installing and running the developed expert system.

INSTALLATION TASK

Follow these steps to load the expert system onto your hard disk:

1. Create a directory for the expert system in your hard disk:

    a) At the DOS prompt (C >), type: md VPX

    and press Enter key.

    b) Now type: cd\ VPX

    The prompt on your screen will probably be: C:\VPX>

2. Copy the expert system onto your hard disk.

    You are now ready to copy all of the expert system files onto your hard disk. Insert the expert system floppy diskettes (Disk #1 and Disk #2) in the A drive. Type:

    copy A:*.* C:\VPX

    and press Enter key.

RUNNING A CONSULTATION

To start a consultation, make sure the PSSE software package (Power System Simulator Engineering) has already been installed onto your computer, and follow these steps:

Step A: Make sure the current directory contains the expert system (C:\vpx). At the DOS prompt type VPX and press Enter key. This bring you to the Main Menu.

Step B: If you want to see a record of the paths taken by the inference engine then,

choose 5Tree, and
choose 3Graphics.

This displays a consultation trace in tree form. Follow the instructions on the screen to move around the tree. When you have seen enough, press Esc to return to the Tree Menu, then choose 4Quit to go back to the Main Menu.

Step C: Choose 6Filename. The question will appear on the screen:

"What is the name of the knowledge base you wish to use ?"

AEP CAPPA SENSI STABIL TAS VCONTROL

Highlight the filename that you are about to consult and press Enter. The Main Menu will appear again.

Note that the expert system contains two sample applications that developed for voltage and reactive power control of the test power systems: AEP 14-bus system (AEP), and North-East Tasmania subsystem (TAS).

Therefore, only two filenames that should be highlighted: "AEP" and "TAS". The others are the filenames of the knowledge-base programs which will be used during a consultation.

Step D: Choose 4Consult. This begins the consultation, it will automatically start running with the first screen is an Introduction Menu. During a consultation questions will be prompted to move from one screen to the next. To select an option (Yes/No) on the screen, use the Arrow keys to highlight it then press Enter key and End key.

The following is the trace of how the expert system formulates the problem.

Starting with an Introduction Menu

Display one-line diagram of the power network

Calculate security margin

Select contingency outage

Calculate network sensitivity factors

Voltage /Reactive power control actions

Advice related to Reactive power compensation study

Note that the results of the consultation will be printed to both the screen and the printer.

At the end of the consultation. Message related to the Reactive Power Compensation study is displayed. Then it brings you back to the Main Menu.

If the message is: "Reactive Power Compensation is not required.", then from the Main Menu you can choose 8Quit to complete the consultation. Otherwise, you should continue the consultation by following these steps:

Step E: At the Main Menu, choose 6Filename.

The question will appear on the screen:

"What is the name of the knowledge base you wish to use ?"

AEP CAPPA SENSI STABIL TAS VCONTROL

Highlight "CAPPA" and press Enter. The Main Menu will appear again, then choose 4Consult.This continues the consultation. The results of the consultation on reactive power compensation will also be printed to both the screen and the printer. At the end of this consultation, It will bring you back to the Main Menu.

Step F: Now choose 8Quit. You are now back in DOS.

APPENDIX C

Includes:

A. AEP TEST SYSTEM

AI. DATA

- One line diagram
- Table A1: Impedance and line charging data
- Table A2: Regulated bus data
- Table A3: Transformer data
- Table A4: Switched capacitor data
- Load flow input data file
- Switched capacitor bank data file

AII. RESULT

- Table A5(a): Result of voltage/ reactive power control study for line 100-500 outage.
- Table A5(b): Reactive power sources settings for line 100-500 outage.
- Table A5(c): Additional shunt capacitors allocation for line 100-500 outage.
- Table A6 : Result of voltage/ reactive power control study for base case.
- Table A7 : Result of voltage/ reactive power control study for line 100-200 outage.
- Table A8 : Result of voltage/ reactive power control study for line 200-400 outage.
- Table A9 : Result of voltage/ reactive power control study for line 600-1300 outage.
- Table A10 : Result of voltage/ reactive power control study for line 900-1400 outage.

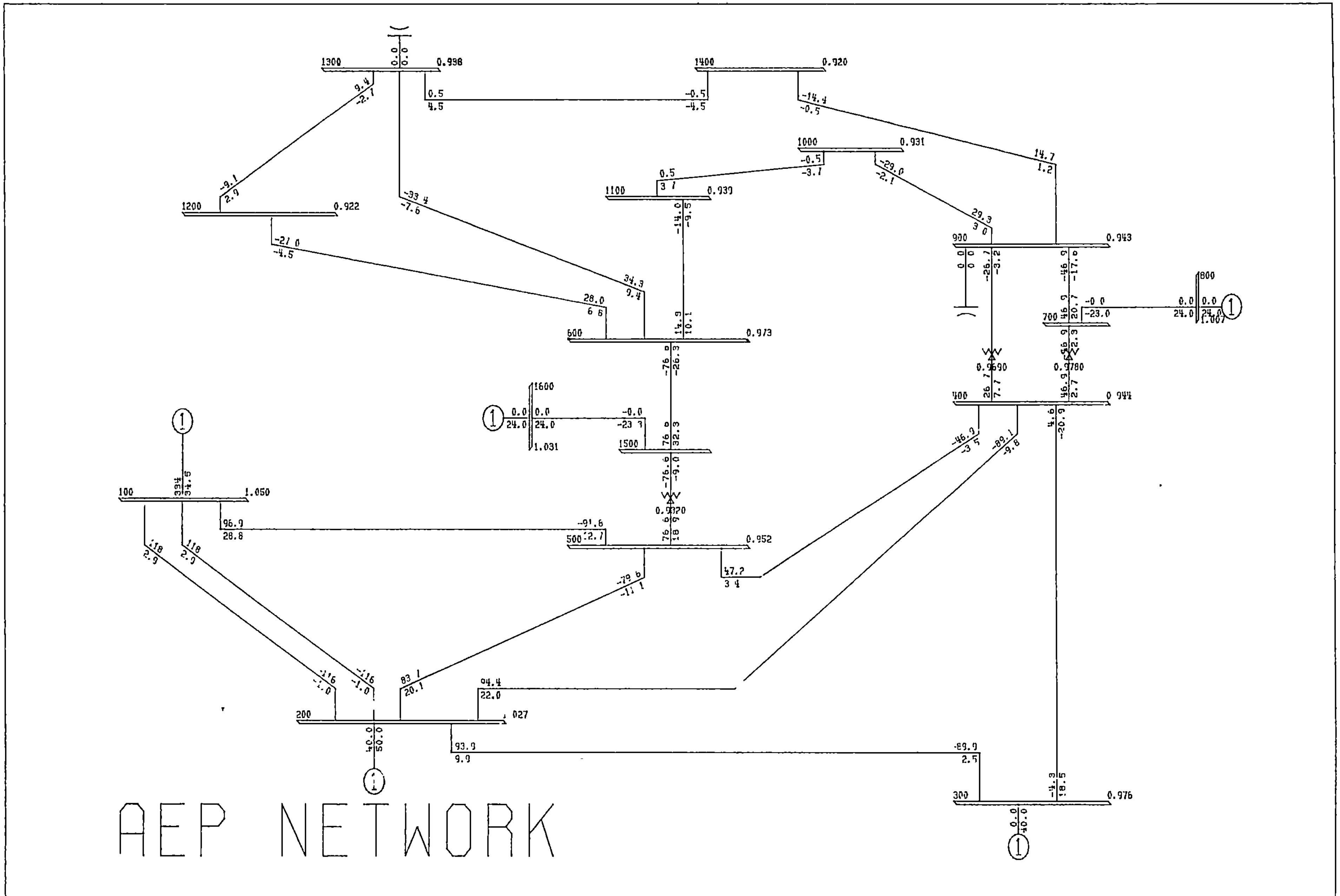
B. NORTH_EAST TASMANIA SUBSYSTEM

BI. DATA

- One line diagram
- Table B1: Impedance and line charging data
- Table B2: Regulated bus data
- Table B3: Transformer data
- Load flow input data file

BII. RESULT

- Table B4(a): Result of voltage/ reactive power control study for line 100-300 outage.
- Table B4(b): Reactive power sources settings for line 100-300 outage.
- Table B5 : Result of voltage/ reactive power control study for base case.
- Table B6 : Result of voltage/ reactive power control study for line 100-400 outage.
- Table B7 : Result of voltage/ reactive power control study for line 300-500 outage.



V∈Δ¬×θ/Rθ¬πΔλ—θ ∑| θ≤ πΔ≤∈ ≥Δ¢φ∫– AEP.DAT PSS/E RAW DATA FORMAT FOR LOADFLOW FRI, AUG 14 1992 11:11	KV: ≤24 , ≤44 , ≤140	BUS - VOLTAGE (PU) BRANCH - MW/MVAR EQUIPMENT - MW/MVAR

C1

A. AEP TEST SYSTEM

Table A1: Impedance and line charging data

Line designation	Resistance p.u	Reactance p.u	Line charging p.u
100-200	0.01938	0.05917	0.0264
100-500	0.05403	0.22304	0.0246
200-300	0.04699	0.19797	0.0219
200-400	0.05811	0.17632	0.0187
200-500	0.05695	0.17388	0.0170
300-400	0.06701	0.17103	0.0173
400-500	0.01335	0.04211	0.0064
400-700	0	0.20912	0
400-900	0	0.55618	0
500-1500	0	0.16510	0
600-1100	0.09498	0.19890	0
600-1200	0.12291	0.25581	0
600-1300	0.06615	0.13027	0
600-1500	0	0.08690	0
700-800	0	0.17615	0
700-900	0	0.11001	0
900-1000	0.03181	0.08450	0
900-1400	0.12711	0.27038	0
1000-1100	0.08205	0.19207	0
1200-1300	0.22092	0.19988	0
1300-1400	0.17093	0.34802	0
1500-1600	0	0.13910	0

Table A2: Regulated bus data

Bus number	Voltage magnitude p.u	Max. capacity MVAr	MW	Min. capacity MVAr	MW
200	1.045	50	70	-40	30
300	1.010	40	0	0	0
800	1.040	24	0	-6	0
1600	1.040	24	0	-6	0

Table A3: Transformer data

Transformer designation	Tap setting
400 - 700 400 - 900 500 - 1500	0.978 0.969 0.932

Table A4: Switched capacitor data

Bus number	Susceptance
900 1300	4x 5 MVAr bank 4x 5 MVAr bank

Note:

- Impedance and line charging susceptance in p.u on 100 MVA base
- Line charging one-half of total charging of line

Filename: AEP.dat

```
0     100.00             / THU, FEB 20 1992  11:35
Voltage/Reactive power control study- AEP.DAT
PSS/E  RAW DATA FORMAT FOR LOADFLOW
 100 3  0.0  0.0  0.00   0.00   1 1.00   0.00 'bus 1    ' 110.00   1
 200 2  0.0  0.0  0.00   0.00   1 1.00   0.00 'bus 2    ' 110.00   1
 300 2 94.2 19.0  0.00   0.00   1 1.00   0.00 'bus 3    ' 110.00   1
 400 1 57.8 23.9  0.00   0.00   1 1.00   0.00 'bus 4    ' 110.00   1
 500 1 47.6  1.6  0.00   0.00   1 1.00   0.00 'bus 5    ' 110.00   1
 600 1  0.0  0.0  0.00   0.00   1 1.00   0.00 'bus 6    '  22.00   1
 700 1  0.0  0.0  0.00   0.00   1 1.00   0.00 'bus 7    '  22.00   1
 800 2  0.0  0.0  0.00   0.00   1 1.00   0 00  bus 8    '  22.00   1
 900 1 29.5 16.6  0.00   0.00   1 1.00   0 00 'bus 9    '  22.00   1
1000 1 29.5  5.8  0.00   0.00·  1 1 00   0.00 'bus 10   '  22.00   1
1100 1 13.5  5.8  0.00   0.00   1 1.00   0.00 'bus 11   '  22.00   1
1200 1 36.1  1.6  0.00   0.00   1 1.00   0.00 'bus 12   '  22.00   1
1300 1 23.5  5.8  0.00   0.00   1 1.00   0.00 'bus 13   '  22.00   1
1400 1 14.9  5.0  0.00   0.00   1 1.00   0.00 'bus 14   '  22.00   1
1500 1  0.0  0.0  0.00   0.00   1 1.00   0.00 'bus 15   '  22.00   1
1600 2  0.0  0.0  0.00   0.00   1 1.00   0 00 'bus 16   '  22.00   1
0
 100 1  0.0  0.0 300.0 -300.0 1.050  0 500.0 0.0 0.20 0.0 0.0 1.0 1 100.0 400
 200 1 40.0  0.0  50.0  -40.0 1.045  0 100.0 0.0 0.20 0.0 0 0 1.0 1 100.0  70
 300 1  0.0  0.0  40.0    0.0 1 010  0  70.0 0.0 0.20 0.0 0.0 1.0 1 100.0   0
 800 1  0.0  0.0  24.0   -6.0 1 040  0  30.0 0.0 0.20 0.0 0.0 1.0 1 100.0   0
1600 1  0.0  0.0  24.0   -6.0 1.040  0  30.0 0.0 0.20 0.0 0.0 1.0 1 100.0   0
0
 100  200 1 0.01938  0.05917  0.0528 0.0 0.0 0.0,,,    0.0   0.0 0.0 0.0 1
 100  200 2 0.01938  0.05917  0.0528 0.0 0.0 0.0,,,    0.0   0.0 0.0 0.0 1
 100  500 1 0.05403  0.22304  0.0492 0.0 0.0 0.0,,,    0.0   0.0 0.0 0.0 1
 200  300 1 0.04699  0.19797  0.0438 0.0 0.0 0.0,,,    0.0   0.0 0.0 0.0 1
 200  400 1 0.05811  0.17632  0.0374 0.0 0.0 0.0,,,    0.0   0.0 0.0 0.0 1
 200  500 1 0.05695  0.17388  0.0340 0 0 0.0 0.0,,,    0.0   0.0 0.0 0.0 1
 300  400 1 0.06701  0.17103  0.0346 0.0 0.0 0.0,,,    0.0   0.0 0.0 0.0'1
 400  500 1 0.01335  0.04211  0.0128 0.0 0.0 0.0,,,    0.0   0.0 0.0 0.0 1
 400  700 1 0.0      0.20912  0.0  0.0 0.0 0.0 0.978 0.0 0.0 0.0 0.0 0.0 1
 400  900 1 0.0      0.55618  0.0  0.0 0.0 0.0 0.969 0.0 0.0 0.0 0.0 0.0 1
 500 1500 1 0.0      0.16510  0.0  0.0 0.0 0.0 0.932 0.0 0.0 0.0 0.0 0.0 1
 600 1100 1 0.09498  0.19890  0.0     0.0 0.0 0.0,,,   0.0 0.0 0.0 0.0 1
 600.1200 1 0.12291  0.25581  0.0     0.0 0.0 0.0,,,   0.0 0.0 0.0 0.0 1
 600 1300 1 0.06615  0.13027  0.0     0.0 0.0 0.0,,,   0.0 0.0 0.0 0.0 1
1500 1600 1 0.0      0.13910  0.0     0.0 0.0 0.0,,,   0.0 0.0 0.0 0.0 1
1500  600 1 0.0      0.08690  0.0     0.0 0.0 0.0,,,   0.0 0.0 0.0 0.0 1
 700  800 1 0.0      0.17615  0.0     0.0 0.0 0.0,,,   0.0 0.0 0.0 0.0 1
 700  900 1 0.0      0.11001  0.0     0.0 0.0 0.0,,,   0.0 0.0 0.0 0.0 1
 900 1000 1 0.03181  0.08450  0.0     0.0 0.0 0.0,,,   0.0 0.0 0.0 0.0 1
 900 1400 1 0.12711  0.27038  0.0     0.0 0.0 0.0,,,   0.0 0.0 0.0 0.0 1
1000 1100 1 0.08205  0.19207  0.0     0.0 0.0 0.0,,,   0.0 0.0 0.0 0.0 1
1500  600 1 0.0      0.08690  0.0     0.0 0.0 0.0,,,   0.0 0.0 0.0 0.0 1
 700  800 1 0.0      0.17615  0.0     0.0 0.0 0.0,,,   0.0 0.0 0.0 0.0 1
 700  900 1 0.0      0.11001  0.0     0.0 0.0 0.0,,,   0.0 0.0 0.0 0.0 1
 900 1000 1 0.03181  0.08450  0.0     0.0 0.0 0.0,,,   0.0 0.0 0.0 0.0 1
 900 1400 1 0 12711  0.27038  0.0     0.0 0.0 0.0,,,   0 0 0.0 0.0 0.0 1
1000 1100 1 0.08205  0.19207  0.0     0.0 0.0 0.0,,,   0.0 0.0 0.0 0.0 1
1200 1300 1 0.22092  0.19988  0.0     0.0 0 0 0.0,..   0.0 0.0 0.0 0 0 1
1300 1400 1 0.17093  0.34802  0.0     0.0 0.0 0.0,,,   0.0 0.0 0.0 0.0 1
0
 400   700 1      400  1.100  0.9000  1.15000  0.90000  0.00625 0 1
 400   900 1      400  1.100  0.9000  1.15000  0.90000  0.00625 0 1
 500  1500 1      500  1 100  0.9000  1.15000  0.90000  0.00625 0 1
0
0
0
  900  1  1.05  0.95  0  0.0  4 5 0
 1300  1  1 05  0.95  0  0 0  4 5.0
0
0
0
0
0
```

Filename: SWITCHCP.dat

SWITCHED SHUNT CAPACITOR DATA FOR REACTIVE COMPENSATION STUDY

BUS NUMBER	INSTALLED CAPACITY IN MVAR (QMAX)	BANK SIZE
900	20.0	5.0
1300	20 0	5.0

Table A5: Result of voltage /Reactive power control study
(a)

[contingency case: line 100 - 500 outage]

Bus number	Voltage magnitude (p.u)				
	No VAR control		VAR control		VAR control & VAR allocation
100	1.0500		1.0500		1.0500
200	0.9855		1.0090		1.0224
300	0.8925	*	0.9471	*	0.9801
+ 400	0.8298	*	0.9086	*	0.9573
+ 500	0.8285	*	0.9077	*	~~0~~.9500
+ 600	0.8269	*	1.0046		1.0316
+ 700	0.8347	*	0.9982		1.0267
800	0.8826	*	1.0389		1.0400
+ 900	0.8050	*	0.9838		1.0162
+ 1000	0.7880	*	0.9707		1.0027
+ 1100	0.7919	*	0.9751		1.0050
+ 1200	0.7656	*	0.9659		0.9950
+ 1300	0.7865	*	0.9897		1.0189
+ 1400	0.7722	*	0.9668		0.9985
+ 1500	0.8573	*	1.0130		1.0373
1600	0.8946	*	1.0400		1.0400
Total system losses (MW)	50.24		40.61		38.14

Note:
+ controlled variable (ie. load bus)
* under-voltage bus

TableA5 : Additional shunt capacitors allocation
(c)

Bus number	Max. bank size MVAr	MVAr required
400	42	58
500	39	14

Table A5: Reactive power sources settings
(b)

Control variables	No VAR control	VAR control	VAR control & VAR allocation
- OLTC Transformers			
Tap:			
From bus - To bus			
400 - 700	0.9780	0.9217	0.9217
400 - 900	0.9690	0.9752	0.9752
500 - 1500	0.9320	0.9007	0.9007
- Switched capacitors			
MVAr in used:			
Bus number			
900	0	20	20
1300	0	20	20
- Generators			
Terminal voltage (p.u)			
Bus number			
100	1.050	1.050	1.050
200	1.045	1.045	1.045
300	1.010	1.010	1.010
800	1.040	1.040	1.040
1600	1.040	1.040	1.040
- Additional VAR required (MVAr)			
Bus number			
400	0	0	58
500	0	0	14

Table A6 : Result of voltage /Reactive power control study

[contingency case: base case]

Bus number	Voltage magnitude (p.u)		
	Initial		Final
100	1.0500		1.0500
200	1.0270		1.0401
300	0.9764		1.0094
+ 400	0.9443	*	0.9937
+ 500	0.9524		0.9912
+ 600	0.9734		1.0048
+ 700	0.9652		1.0067
800	1.0072		1.0400
+ 900	0.9431	*	0.9848
+ 1000	0.9309	*	0.9716
+ 1100	0.9389	*	0.9755
+ 1200	0.9225	*	0.9565
+ 1300	0.9384	*	0.9725
+ 1400	0.9207	*	0.9510
+ 1500	0.9992		1.0268
1600	1.0315		1.0400
Total system losses (MW)	27.07		25.14
OLTC transf. TAP:			
400 - 700	0.9780		0.9780
400 - 900	0.9690		0.9690
500 - 1500	0.9320		0.9320
Generator ter. voltage (p.u)			
100	1.0500		1.0500
200	1.0450		1.0450
300	1.0100		1.0100
800	1.0400		1.0400
1600	1.0400		1.0400
Switched cap. (MVAr)			
900	0		0
1300	0		0
Additional VAR required(MAVr)			
400	0		58
500	0		14

Table A7: Result of voltage /Reactive power control study

[contingency case: line 100 - 200 outage]

Bus number	Voltage magnitude (p.u) Initial	Voltage magnitude (p.u) Final
100	1.0500	1.0500
200	1.0013	1.0295
300	0.9501	1.0003
+ 400	0.9189 *	0.9863
+ 500	0.9287 *	0.9841
+ 600	0.9450 *	1.0009
+ 700	0.9377 *	1.0027
800	0.9808	1.0400
+ 900	0.9144 *	0.9801
+ 1000	0.9017 *	0.9669
+ 1100	0.9096 *	0.9711
+ 1200	0.8924 *	0.9523
+ 1300	0.9089 *	0.9683
+ 1400	0.8909 *	0.9553
+ 1500	0.9717	1.0230
1600	1.0049	1.0400
Total system losses (MW)	32.79	29.62
OLTC transf. TAP:		
400 - 700	0.9780	0.9780
400 - 900	0.9690	0.9690
500 - 1500	0.9320	0.9320
Generator ter. voltage (p.u)		
100	1.0500	1.0500
200	1.0450	1.0450
300	1.0100	1.0100
800	1.0400	1.0400
1600	1.0400	1.0400
Switched cap. (MVAr)		
900	0	0
1300	0	0
Additional VAR required(MAVr)		
400	0	58
500	0	14

Table A8 : Result of voltage /Reactive power control study

[contingency case: line 200 - 400 outage]

Bus number	Voltage magnitude (p.u) Initial		Final
100	1.0500		1.0500
200	1.0209		1.0415
300	0.9260	*	1.0000
+ 400	0.8609	*	0.9783
+ 500	0.8841	*	0.9801
+ 600	0.8866	*	1.0298
+ 700	0.8760	*	1.0049
800	0.9218	*	1.0400
+ 900	0.8504	*	0.9888
+ 1000	0.8371	*	0.9792
+ 1100	0.8469	*	0.9917
+ 1200	0.8294	*	0.9912
+ 1300	0.8469	*	1.0129
+ 1400	0.8261	*	0.9802
+ 1500	0.9163	*	1.0409
1600	0.9513		1.0600
Total system losses (MW)	39.16		31.82
OLTC transf. TAP:			
400 - 700	0.9780		0.9780
400 - 900	0.9690		0.9690
500 - 1500	0.9320		0.9320
Generator ter. voltage (p.u)			
100	1.0500		1.0500
200	1.0450		1.0450
300	1.0100		1.0100
800	1.0400		1.0400
1600	1.0400		1.0600
Switched cap. (MVAr)			
900	0		0
1300	0		20
Additional VAR required(MAVr)			
400	0		58
500	0		14

Table A9 : Result of voltage /Reactive power control study

[contingency case: line 600 - 1300 outage]

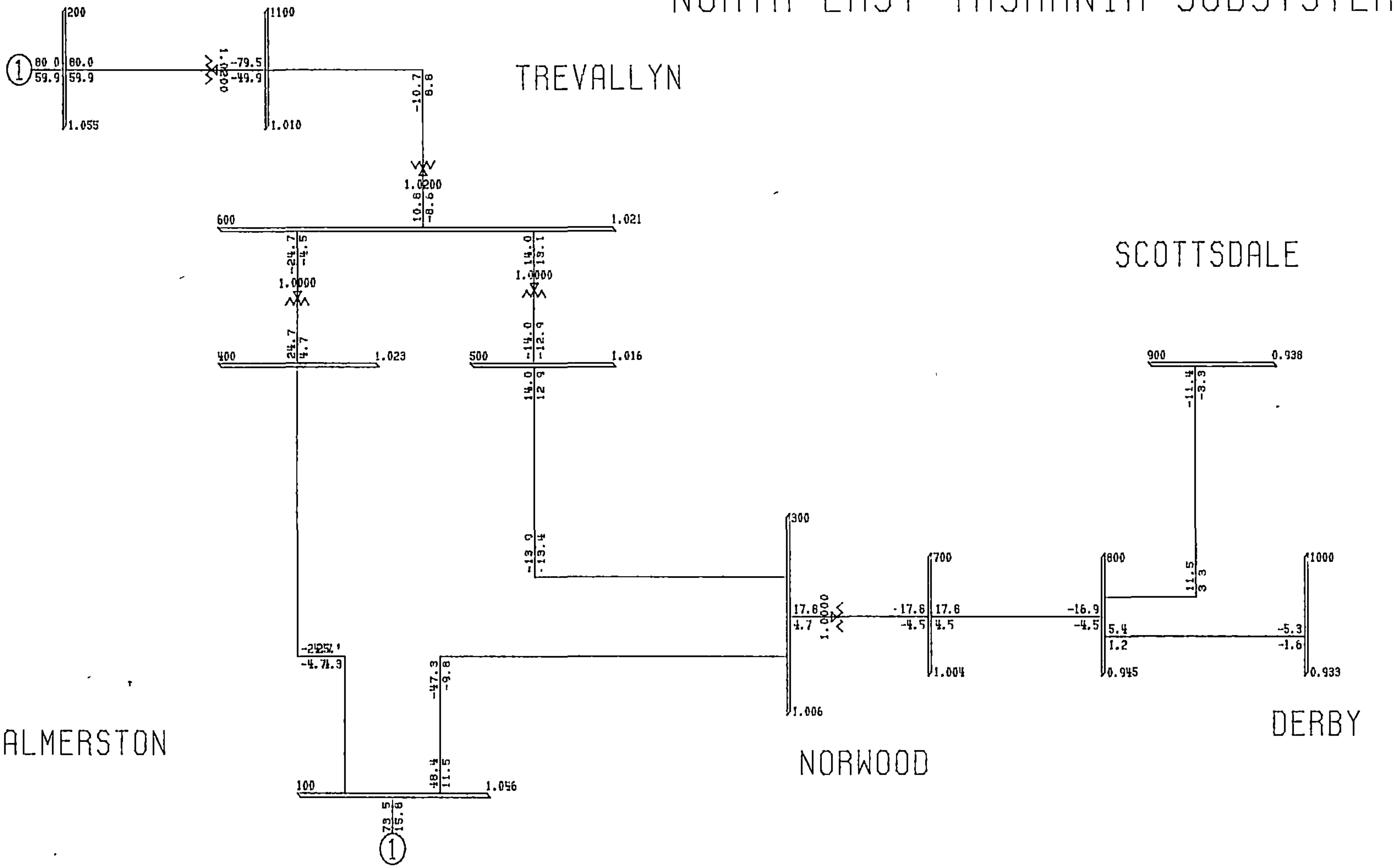
Bus number	Voltage magnitude (p.u) Initial		Voltage magnitude (p.u) Final
100	1.0500		1.0500
200	1.0230		1.0408
300	0.9675		1.0100
+ 400	0.9317	*	0.9964
+ 500	0.9426	*	0.9960
+ 600	0.9606		1.0308
+ 700	0.9381	*	1.0094
800	0.9811		1.0400
+ 900	0.9094	*	0.9899
+ 1000	0.9000	*	0.9802
+ 1100	0.9160	*	0.9924
+ 1200	0.8607	*	0.9714
+ 1300	0.8159	*	0.9559
+ 1400	0.8450	*	0.9538
+ 1500	0.9875		1.0435
1600	1.0202		1.0504
Total system losses (MW)	32.36		28.11
OLTC transf. TAP:			
400 - 700	0.9780		0.9780
400 - 900	0.9690		0.9690
500 - 1500	0.9320		0.9320
Generator ter. voltage (p.u)			
100	1.0500		1.0500
200	1.0450		1.0450
300	1.0100		1.0100
800	1.0400		1.0400
1600	1.0400		1.0504
Switched cap. (MVAr)			
900	0		0
1300	0		20
Additional VAR required(MAVr)			
400	0		58
500	0		14

Table A10: Result of voltage /Reactive power control study

[contingency case: line 900 - 1400 outage]

Bus number	Voltage magnitude (p.u)		
	Initial		Final
100	1.0500		1.0500
200	1.0258		1.0396
300	0.9741		1.0091
+ 400	0.9412	*	0.9935
+ 500	0.9468	*	0.9874
+ 600	0.9527		1.0295
+ 700	0.9642		1.0211
800	1.0062		1.0504
+ 900	0.9425	*	1.0084
+ 1000	0.9268	*	0.9959
+ 1100	0.9292	*	1.0007
+ 1200	0.8956	*	0.9834
+ 1300	0.9045	*	0.9963
+ 1400	0.8528	*	0.9501
+ 1500	0.9826		1.0487
1600	1.0155		1.0504
Total system losses (MW)	28.77		26.05
OLTC transf. TAP:			
400 - 700	0.9780		0.9780
400 - 900	0.9690		0.9377
500 - 1500	0.9320		0.9007
Generator ter. voltage (p.u)			
100	1.0500		1.0500
200	1.0450		1.0450
300	1.0100		1.0100
800	1.0400		1.0504
1600	1.0400		1.0504
Switched cap. (MVAr)			
900	0		0
1300	0		10
Additional VAR required(MAVr)			
400	0		58
500	0		14

NORTH EAST TASMANIA SUBSYSTEM



V∈Δ¬×θ/Rθ¬πΔλ—θ ∑| θ≤ πΔ≤ε ≥ΔΦΦ∫– NE Δ¬≥.Φ¬Δ PSS/E RAW DATA FORMAT FOR LOADFLOW THU, SEP 17 1992 08:52	KV: ≤24 , ≤66 , ≤140	BUS - VOLTAGE (PU) BRANCH - MW/MVAR EQUIPMENT - MW/MVAR

B. NORTH-EAST TASMANIA SUBSYSTEM

Table B1: Impedance and line charging data

Line designation	Resistance p.u	Reactance p.u	Line charging p.u
100-300	0.05060	0.14990	0.00778
100-400	0.05620	0.19400	0.00770
200-1100	0.00580	0.11160	0.0
300-500	0.01680	0.05770	0.00313
300-700	0.0	0.04000	0.0
400-600	0.00130	0.03970	0.0
500-600	0.00130	0.03970	0.0
600-1100	0.00580	0.11160	0.0
700-800	0.27100	0.24880	0.00406
800-900	0.04380	0.03500	0.00058
800-1000	0.16230	0.14500	0.00250

Table B2: Regulated bus data

Bus number	Voltage magnitude p.u	Max. capacity MVAr	MW	Min. capacity MVAr	MW
200	1.055	60	100	-60	30

Table B3: Transformer data

Transformer designation	Tap setting
200 - 1100	1.020 fixed
300 - 700	1.000
400 - 600	1.000
500 - 600	1.000
600 - 1100	1.020 fixed

Note:

- Impedance and line charging susceptance in p.u on 100 MVA base
- Line charging one-half of total charging of line

Filename: TAS.dat

```
0    100.00          / THU, FEB 20 1992  12:26
Voltage/Reactive power control study- NE tas.dat
PSS/E  RAW DATA FORMAT FOR LOADFLOW
 100 3    0.00     0.00 0.0 0.0 1 1.04550    0.0000 'PLML    ' 110.00   1
 200 2    0.00     0.00 0.0 0.0 1 1.05500    1.2063 'TRMC    ' 11.000   1
 300 1   43.35    18.47 0.0 0.0 1 0.99784   -3.5026 'NRWD    ' 110.00   1
 400 1    0.00     0.00 0.0 0.0 1 1.01221   -2.2768 'TRVP    ' 110.00   1
 500 1    0 00     0.00 0.0 0.0 1 1.00462   -3.1212 'TRVN    ' 110.00   1
 600 1    0.00     0.00 0.0 0.0 1 1.00777   -2 8158 'TRVL    ' 110.00   1
 700 1    0 00     0.00 0.0 0.0 1 0.99598   -3.9138 'NO.R    ' 88.000   1
 800 1    0.00     0.00 0.0 0.0 1 0.93555   -5.8124 'S.T.    ' 88.000   1
 900 1   11.45     3.34 0.0 0.0 1 0.92891   -5.9811 'SCOT    ' 88.000   1
1000 1    5.33     1.56 0.0 0.0 1 0.92406   -6.1787 'DRBY    ' 88.000   1
1100 1   90.22    41.11 0.0 0.0 1 1.02424   -3.4811 'TREV    ' 22.000   1
0
 100 1 73.54 27.590 100 -100 1.0455 0 200 0 0 2 0 0 1.0 1 100 9999.0 -9999.0
 200 1 80.00 47.083  60  -60 1.0550 0 120 0 0.2 0 0 1.0 1 100 100.0 30.0
0
 100  300 1 0.0506 0.1499 0.01555 0.0 0.0 0.0,,.0.0 0.0 0.0 0.0 1
 100  400 1 0.0562 0.1940 0.01539 0.0 0.0 0.0,,,0.0 0.0 0.0 0.0 1
1100  200 1 0.0058 0.1116 0.00000 0.0 0.0 0.0 1.02 0.0 0.0 0.0 0.0 0.0 1
 300  500 1 0.0168 0.0577 0.00625 0.0 0.0 0.0,,,0.0 0.0 0.0 0.0 1
 700  300 1 0.0000 0.0400 0.00000 0.0 0.0 0.0 1.00 0.0 0.0 0.0 0.0 0.0 1
 600  400 1 0.0013 0.0397 0.00000 0.0 0.0 0.0 1.00 0.0 0.0 0.0 0.0 0.0 1
 600  500 1 0.0013 0.0397 0.00000 0.0 0.0 0.0 1.00 0.0 0.0 0.0 0.0 0.0 1
 600 1100 1 0.0058 0.1116 0.00000 0.0 0.0 0.0 1.02 0.0 0.0 0.0 0.0 0.0 1
 700  800 1 0.2710 0.2488 0 00811 0.0 0.0 0.0,,,0.0 0.0 0.0 0.0 1
 800  900 1 0.0438 0.0350 0.00115 0.0 0.0 0.0,,,0.0 0.0 0 0 0.0 1
 800 1000 1 0.1623 0.1450 0.00499 0.0 0.0 0.0,,,0.0 0.0 0.0 0 0 1
0
 700   300 1     700  1.10000  0.90000  1.15000  0.95000  0.00625 0 1
 600   400 1     600  1.10000  0.90000  1.15000  0.90000  0.00625 0 1
 600   500 1     600  1.10000  0.90000  1.15000  0.90000  0.00625 0 1
0
0
0
0
0
0
0
0
```

Table B4: (a) Result of voltage /Reactive power control study

[contingency case: line 100 - 300 outage]

Bus number	Voltage magnitude (p.u)	
	No VAR control	VAR control
100	1.0455	1.0560
200	0.9741	0.9995
+ 300	0.8933 *	1.0195
+ 400	0.9442 *	0.9642
+ 500	0.9208 *	1.0428
+ 600	0.9335 *	0.9610
+ 700	0.8910 *	1.0432
+ 800	0.8211 *	0.9863
+ 900	0.8135 *	0.9800
+ 1000	0.8078 *	0.9754
+ 1100	0.9230 *	0.9504
Total system losses (MW)	6.8	5.8

Note:
+ controlled variable (ie. load bus)
* under-voltage bus

Table B4: (b) Reactive power sources settings

Control variables	No VAR control	VAR control
- OLTC Transformers		
Tap:		
From bus - To bus		
400 - 600	1.0000	1.0063
500 - 600	1.0000	0.9125
300 - 700	1.0000	1.0250
- Generators		
Terminal voltage (p.u)		
Bus number		
100	1.0455	1.0560
200	1.0550	1.0550

Table B5: Result of voltage /Reactive power control study

[contingency case: base case]

Bus number	Voltage magnitude (p.u)		
	Initial		Final
100	1.0455		1.0455
200	1.0550		1.0550
+ 300	1.0063		1.0064
+ 400	1.0235		1.0235
+ 500	1.0161		1.0162
+ 600	1.0214		1.0214
+ 700	1.0045		1.0234
+ 800	0.9446	*	0.9649
+ 900	0.9380	*	0.9585
+ 1000	0.9332	*	0.9538
+ 1100	1.0104		1.0104
Total system losses (MW)	3.1		3.1
OLTC transf. TAP:			
400 - 600	1.0000		1.0000
500 - 600	1.0000		1.0000
300 - 700	1.0000		1.0187
Generator ter. voltage (p.u)			
100	1.0455		1.0455
200	1.0550		1.0550

Table B6 : Result of voltage /Reactive power control study

[contingency case: line 100 - 400 outage]

Bus number	Voltage magnitude (p.u)		
	Initial		Final
100	1.0455		1.0455
200	1.0243		1.0243
+ 300	0.9818		0.9819
+ 400	0.9879		0.9879
+ 500	0.9848		0.9849
+ 600	0.9879		0.9879
+ 700	0.9799		1.0230
+ 800	0.9181	*	0.9644
+ 900	0.9113	*	0.9580
+ 1000	0.9064	*	0.9533
+ 1100	0.9772		0.9773
Total system losses (MW)	4.5		4.4
OLTC transf. TAP:			
400 - 600	1.0000		1.0000
500 - 600	1.0000		1.0000
300 - 700	1.0000		1.0438
Generator ter. voltage (p.u)			
100	1.0455		1.0560
200	1.0550		1.0550

Table B7 : Result of voltage /Reactive power control study

[contingency case: line 300 - 500 outage]

Bus number	Voltage magnitude (p.u)	
	Initial	Final
100	1.0455	1.0560
200	1.0550	1.0550
+ 300	0.9758	0.9877
+ 400	1.0414	1.0477
+ 500	1.0414	1.0467
+ 600	1.0414	1.0467
+ 700	0.9739	1.0228
+ 800	0.9116 *	0.9643
+ 900	0.9048 *	0.9579
+ 1000	0.8998 *	0.9532
+ 1100	1.0206	1.0234
Total system losses (MW)	3.9	3.7
OLTC transf. TAP:		
400 - 600	1.0000	1.0000
500 - 600	1.0000	1.0000
300 - 700	1.0000	1.0375
Generator ter. voltage (p.u)		
100	1.0455	1.0560
200	1.0550	1.0550