Program Application Guide Volume 1
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Chapter 1

System Behavior and Power System Simulator

1.1. Managing the Data of a Study

PSS®E files give the user great freedom in adapting the handling of input, the recording of cases, and the output to suit the work as it progresses. As with all systems that provide great flexibility and many options, PSS®E also expects the user to be responsible for managing those options, in this case, the files.

PSS®E is able, at any time, to write over the contents of a previously created file. PSS®E does not append to files; each time a user specifies a file's name to a PSS®E file-writing activity, such as Save As, the writing commences at the *start* of that file, destroying the previous contents. (The exception to this rule is writing into a channel output file by the Dynamics Simulation>Run functions.)

This mode of operation in the use of PSS®E and its predecessors, in over 50 years of use, is the preferred way of handling files. It simply requires the user to keep effective records of created files. The best form of record is a concise written catalog, which is a reference during the use of PSS®E, together with a systematic way of assigning filenames. A suggested form, called the File Planning Sheet, which can be used to catalog files and their contents, is provided.

1.2. Overview of System Behavior

1.2.1. Phenomena of Concern

The electric power system converts energy from a raw form (principally heat) into electricity, transmits it from the conversion site to a load site, and delivers it to consumers. The power generation and transmission system is not designed to store energy and its operation requires the rate of conversion of energy at the generating plants to be equal, within a very tight tolerance, to the rate of consumption by the loads. The power system does, nevertheless, store some energy in its electrical and mechanical components.

The energy stored in the power system, while insignificant in relation to the demands of the loads, is a critical factor in the dynamic behavior of the system. There are three ways the power system stores energy:

- The inductances and capacitances of the transmission lines, transformers, and shunt devices.
- The rotating inertia of the turbine-generators and motor-driven loads.
- The thermodynamic processes of the power plants, particularly within the boiler drums.

The amount of energy stored by each of these phenomena can be estimated in terms of the length of time its discharge could maintain full-load system power flows. Table 1.1, "Characterization of Energy Storage in Terms of Time Required for Full-Load System Power Flows to Discharge the Storage"summarizes these times.

Table 1.1. Characterization of Energy Storage in Terms of Time Required for Full-Load System Power Flows to Discharge the Storage

Phenomenon	Seconds at Full System Power Flow
Electromagnetic and Electrostatic Energy Conversion	10^{-6} to 10^{-3} sec.
Rotating Inertial System	10^{-1} to 10 sec.
Thermodynamic System	10 to 10^{3} sec.

The transient processes associated with these energy storages generally occur on a time scale that is similar to the discharge times given in Table 1.1, "Characterization of Energy Storage in Terms of Time Required for Full-Load System Power Flows to Discharge the Storage". The range of time scales is enormous. Electrical transients may be expected to arise and disappear within a few milliseconds, while electromechanical transients take several seconds to run, and thermodynamic transients may persist for many minutes. It is neither practical nor desirable to consider all classes of transients at the same time. It is clear from experience that millisecond-duration electrical transients have no effect upon the rotating inertial motions of generators, and that generator inertial motions have no effect on steam drum pressure dynamics, for example. A major element of the art of power system analysis is the determination of the group of energy storage (or exchange) transients that are pertinent to the study of each specific problem.

This book is principally concerned with power system dynamic behavior associated with the energy stored in the rotating inertias of the system, where transients arise and decay away again within a period of a few seconds. However, while the focus remains on rotor inertial dynamics, it will be necessary to consider both electrical transient behavior of the transmission network and the transient thermodynamic behavior of prime mover systems.

The use of the term *Power System Simulation* in this book refers to the study of transients that affect or have a similar time scale to the inertial motions of turbine-generator rotors. The most widely recognized transient phenomenon of interest here is normally discussed relative to Power System Stability. Discussions of power system stability usually relate to the ability of individual generators to remain in synchronism with one another after a system disturbance such as a ground fault and the subsequent opening of a transmission line.

As early as the 1920s, power engineers treated these transient stability questions using detailed consideration of only the rotor inertia energy storage dynamics and, while they recognized that electromagnetic transients within generator field windings played a significant role, they did not simulate these effects. Such treatment gave fair indications of the ability of systems to survive the first major swing of a disturbance following an electrical fault. These indicators were, however, known to be inaccurate and unreliable when applied to the study of the many other transient behavior problems facing power engineers.

As computational technology advanced, it became possible to extend the spectrum of effects modeled and simulated in dynamic behavior studies far beyond the simple treatment of rotor inertial dynamics. This broader spectrum of modeling and simulation results from both the recognition of new problems by power system engineers and the disappearance of old computational limitations.

1.2.2. Power System Modeling

While the principal concern of this book is the electromechanical transient behavior of the generators and their controls, it is useful to review the modeling of the broad field of system dynamic effects. Figure 1.1, "Single-Phase Ideal Source"through Figure 1.8, "Classical Representation of Source Behind Reactance"summarize the aspects of modeling detail involving machines and networks, and describe each step of the model. These examples show the wide range of modeling detail that can enter into a particular problem solution. The choice of the adequate model for the problem in question requires intimate knowledge of fundamentals and orders of magnitude of effects.

Figure 1.1, "Single-Phase Ideal Source" starts with the consideration from the first principles of a single-phase alternating ideal voltage source connected to a linear network made up of resistance, inductance, and capacitance elements. The mathematical formulation is a set of linear ordinary differential equations.

Figure 1.2, "Three-Phase Ideal Source" extends this problem to the three-phase situation, still describing the network by linear differential equations and the source by ideal voltage sources.

Figure 1.3, "Three-Phase with Saturation" evolves from the case of Figure 1.2, "Three-Phase Ideal Source" to include nonlinearities, such as those caused by saturation of magnetic elements, while still treating generators as ideal voltage sources.

Figure 1.4, "Generation with d and q Axes" expands the detail of the representation of the generator by differential equations in the d and q axes accounting for the transients in rotor and armature currents and their effect on voltage-producing fluxes. Figure 1.4, "Generation with d and q Axes" represents the maximum of detail in both machine and network. Such effects as subsynchronous resonance and harmonics generated by saturation can be studied with this representation.

Figure 1.5, "Network Differential Equations" shows the next step where the network differential equations are reduced to algebraic equations solving for the fundamental frequency voltages and currents, while preserving the time-varying (differential equation) nature of fluxes and rotor speed that give rise to varying magnitude and frequency of generated voltages. Effects of frequency variation on network impedances are included.

Figure 1.6, "Neglect Frequency Effects in Generation Voltages" follows from the model of Figure 1.5, "Network Differential Equations" by neglecting the effect of frequency variations in the generated voltages and in the network parameters. This degree of detail is generally used in stability studies where the user must account for the effects of machine rotor flux variations on synchronizing and damping torques.

Figure 1.7, "Removal of Rotor Flux Differential Equations" shows successive simplifications of the machine model with removal of the rotor flux differential equations and representation of source voltages as constant values behind constant reactances.

Figure 1.8, "Classical Representation of Source Behind Reactance" shows additional successive simplifications of the machine model with removal of the rotor flux differential equations and representation of source voltages as constant values behind constant reactances. Figure 1.8, "Classical Representation of Source Behind Reactance" uses the classical representation of constant voltages behind a transient reactance, symmetrical in both axes.

Source	Network	Nature of Results	Applications and Limitations	Solution Methods and Tools
Ideal sinusoidal source behind constant inductance with constant or varying frequency, single phase.	*R*, *L*, *C* linear elements - treated by differential equations.	Instantaneous time solution of voltages and currents.	Switching surges, recovery voltages. Applicable to *linear* single-phase systems or to symmetrical three-phase systems where transients do not involve unbalances.	TNA, analog computer. Digital computer (with traveling wave or lumped parameter solution methods). Digital differential analyzer.

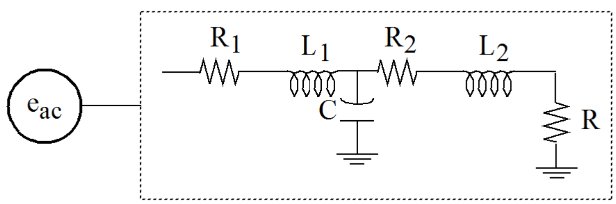


Figure 1.1. Single-Phase Ideal Source

Source	Network	Nature of Results	Applications and Limitations	Solution Methods and Tools
Ideal sinusoidal balanced three-phase sources behind constant inductances in each phase with constant or varying frequency. (Source inductance usually represented by X''_d).	*R*, *L*, *C* linear elements - treated by differential equations of three phases or differential equations of α , β , and ø networks.	Instantaneous time solution of phase voltages and currents and/or α , β , and ø components.	Switching surges, recovery voltages, short circuits. Applicable to linear three-phase systems with or without imbalances. Duration of transients is short relative to flux decay time constants of generators.	TNA, analog computer, Digital computer (with traveling wave or lumped parameter solution methods). Digital differential analyzer.

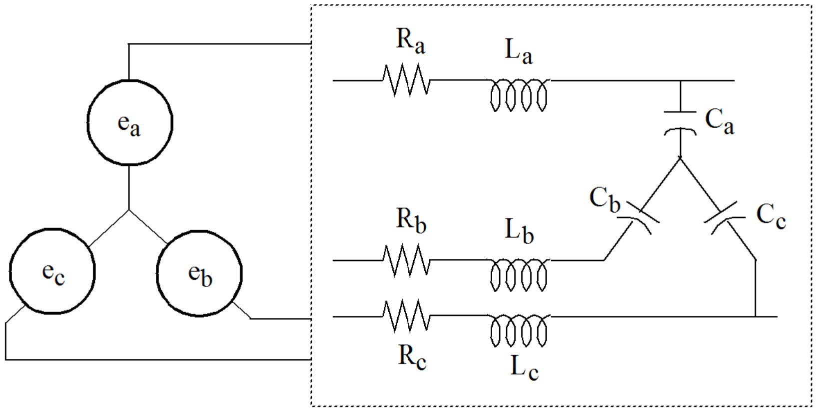


Figure 1.2. Three-Phase Ideal Source

Source	Network	Nature of Results	Applications and Limitations	Solution Methods and Tools
Ideal sinusoidal balanced three-phase sources behind constant inductances in each phase with constant or varying frequency. (Source inductance usually represented by X''_d).	*R*, *L*, *C* elements with nonlinear characteristics (magnetic saturation, thyrite resistors, etc.) described by differential equations of three phases.	Instantaneous time solution of phase voltages and currents.	Switching surges, recovery voltages, energization transients, short circuits. Applicable to nonlinear three-phase systems with or without imbalances. Duration of transients is short, relative to flux decay time constants of generators.	TNA, analog computer. Digital computer (with traveling wave or lumped parameter solution methods). Digital differential analyzer.

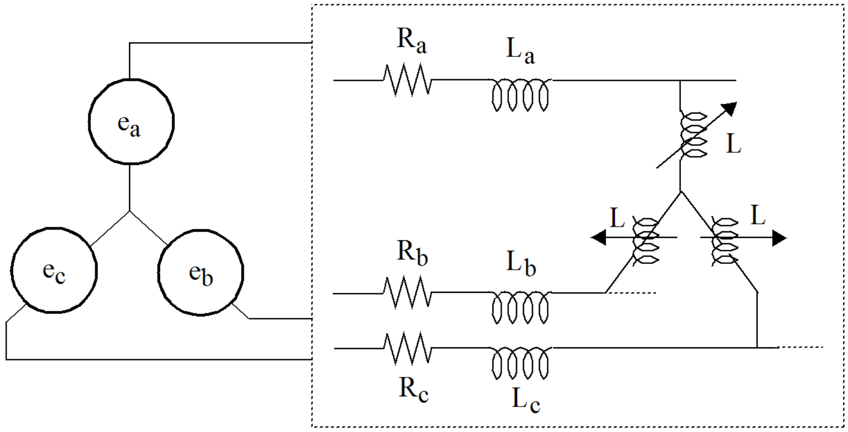


Figure 1.3. Three-Phase with Saturation

Source	Network	Nature of Results	Applications and Limitations	Solution Methods and Tools
Source represented by equations of flux behavior in d and q axes. Instantaneous terminal phase voltages derived from d, q, and o transformation.	R, L, C elements with nonlinear characteristics (magnetic saturation, thyrite resistors, etc.) described by diffrential equations.	Instantaneous time solution of phase voltages, currents, powers, etc.	Switching surges, recovery voltages, energization transients, subsynchronous resonances, short circuits, load rejection transients. Applicable to nonlinear three-phase systems with or without imbalances. Solution takes into account generator flux effects and is valid for short or long durations.	Analog computer (limited scope problem). Digital computer, scaled model of machines and network.

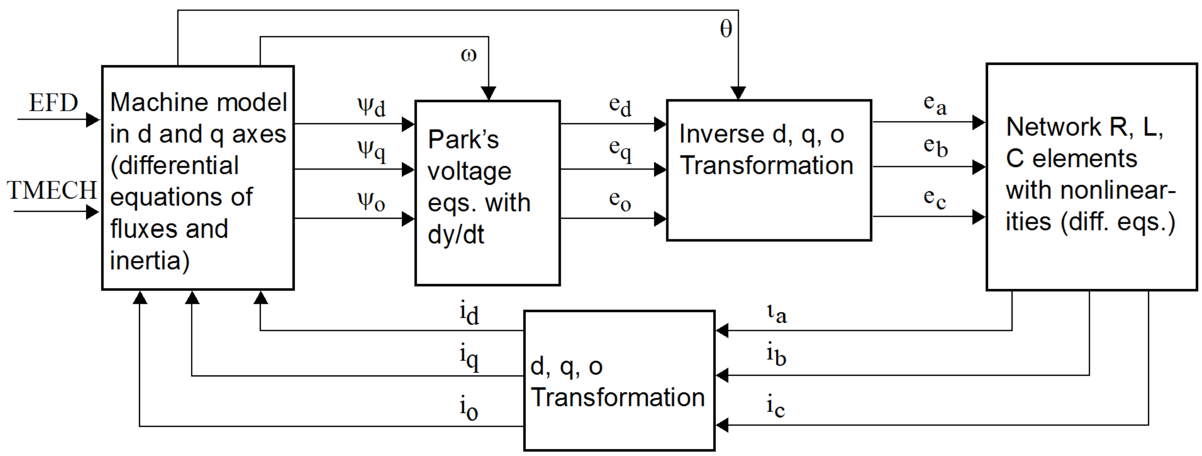


Figure 1.4. Generation with d and q Axes

Source	Network	Nature of Results	Applications and Limitations	Solution Methods and Tools
Source represented by equations of flux behavior in d and q axes. Terminal voltage obtained as fundamental frequency positive-sequence phasor by multiplying flux with speed.	Z(j φ ω), Y(j ω) elements with nonlinear characteristics and frequency dependence. Network equations described by complex algebraic equations.	Fundamental frequency solutions of phase voltages and currents. Expressed as phasors, machine angles, power, etc.	Fundamental frequency transients following load rejections or other balanced network disturbances where frequency effects are significant. Applicable to balanced three-phase sys-	Analog computer (small size problem). Digital computer. Scaled models of machines and network.

Source	Network	Nature of Results	Applications and Limitations	Solution Methods and Tools
Armature and network transients neglected.			tems for fundamental frequency effects over several seconds.	

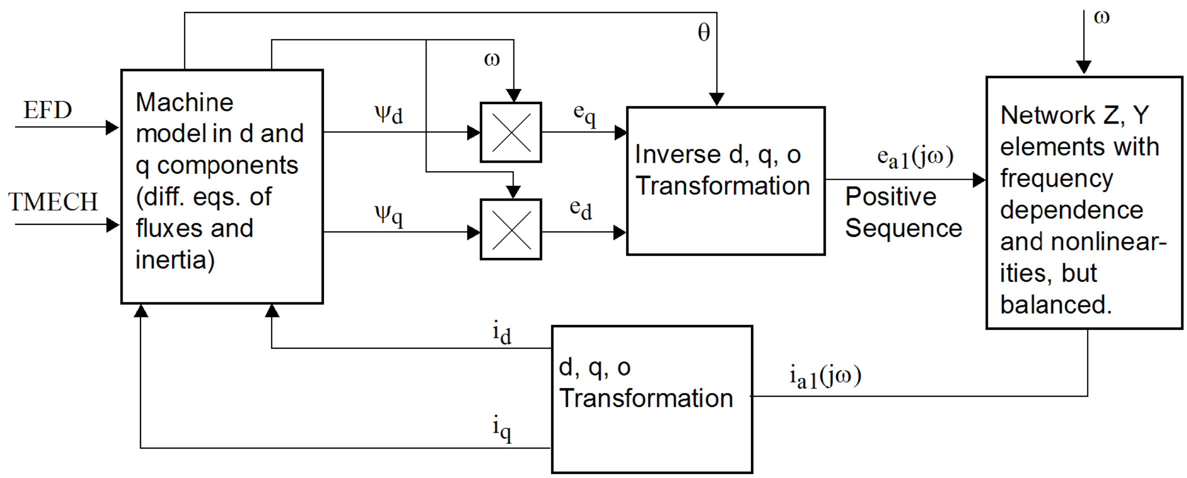


Figure 1.5. Network Differential Equations

Source	Network	Nature of Results	Applications and Limitations	Solution Methods and Tools
Source representation same as Figure 1.5, "Network Differential Equations" except voltage is equal to flux (speed assumed rated).	$Z(j\omega_o)$, $Y(j\omega_o)$ elements with or without nonlinear elements. Network equations described by complex algebraic equations. Negative- and zero-sequence network includes machine.	Fundamental frequency solutions of positive sequence voltages and currents as phasors. Machine angles, speeds, powers (average). (Negative- and zero-sequence quantities can also be obtained.)	Fundamental frequency transients following faults or other disturbances. Machine rotor angles, powers. Applicable to three-phase systems for fundamental frequency effects over several seconds. Stability phenomena.	Analog computer (small size problem). Digital computer. Scaled models of machines and network. Hybrid computers.

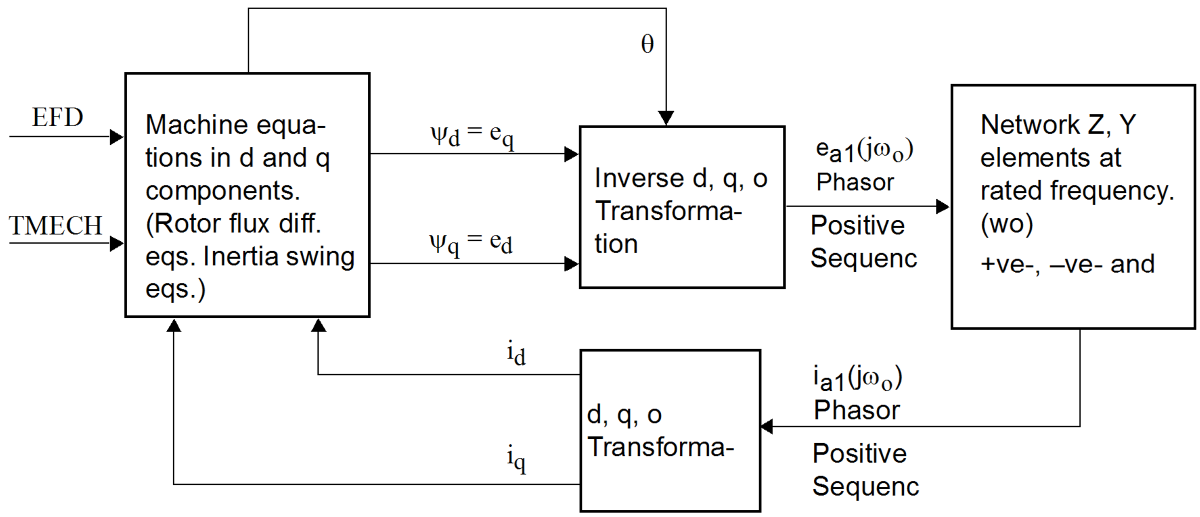


Figure 1.6. Neglect Frequency Effects in Generation Voltages

Source	Network	Nature of Results	Applications and Limitations	Solution Methods and Tools
Source represented as constant voltages behind appropriate reactances in d and q axes. Reactances can be subtransient, transient, or steady-state (synchronous) depending on problem. Machine saliency included.	$Z(j\omega_o)$, $Y(j\omega_o)$ elements with or without nonlinear elements. Network equations described by complex algebraic equations. Negative- and zero-sequence network includes machine.	Fundamental frequency solutions of sequence currents and voltages. If machine swing equations are included, rotor angle transients are obtained (stability).	Fundamental frequency network conditions. Symmetrical short-circuit currents (balanced and unbalanced). With proper choice of machine reactances, may be used for stability calculations. Applicable to three-phase systems for fundamental frequency effects. Used generally for conditions at some instant in time depending on value of source reactance and voltage used. If swing equations are solved (stability) transient reactance values are used and solution approximates conditions in first half-second.	Digital computer.

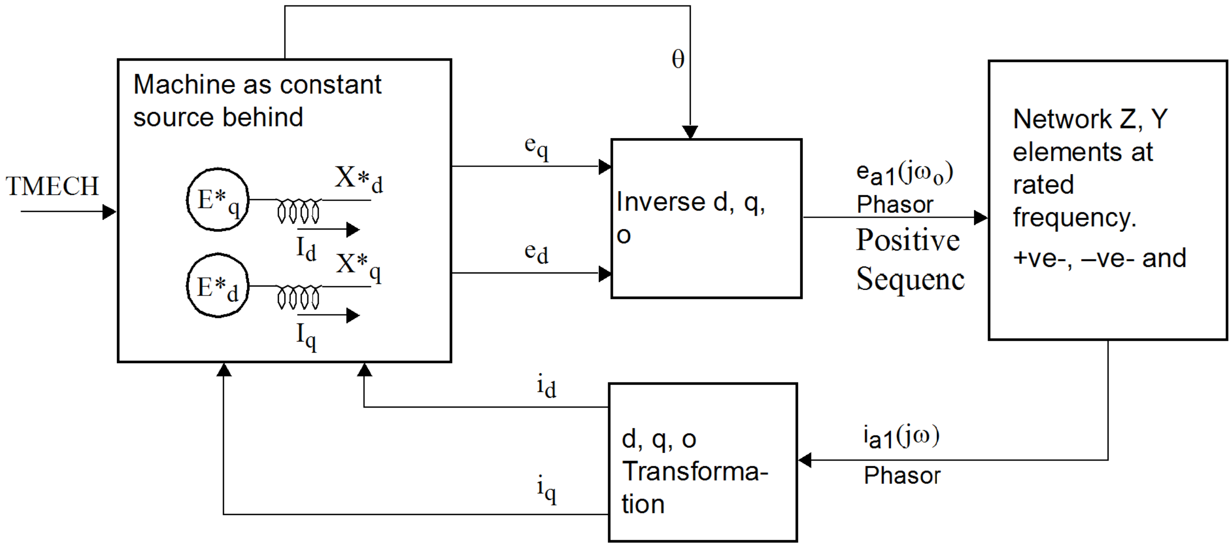


Figure 1.7. Removal of Rotor Flux Differential Equations

Source	Network	Nature of Results	Applications and Limitations	Solution Methods and Tools
Source represented as constant voltage behind an equivalent reactance. Machine saliency neglected.	$Z(j\omega_o)$, $Y(j\omega_o)$ elements with or without nonlinear elements. Network equations described by complex algebraic equations. Negative- and zero-sequence network includes machine.	Fundamental frequency solutions of sequence currents and voltages. If machine swing equations are included, rotor angle transients are obtained (stability classical solution).	Applicable for short-circuit studies(balanced and unbalanced) and first-swing stability studies.	ac network analyzer. Digital computer.

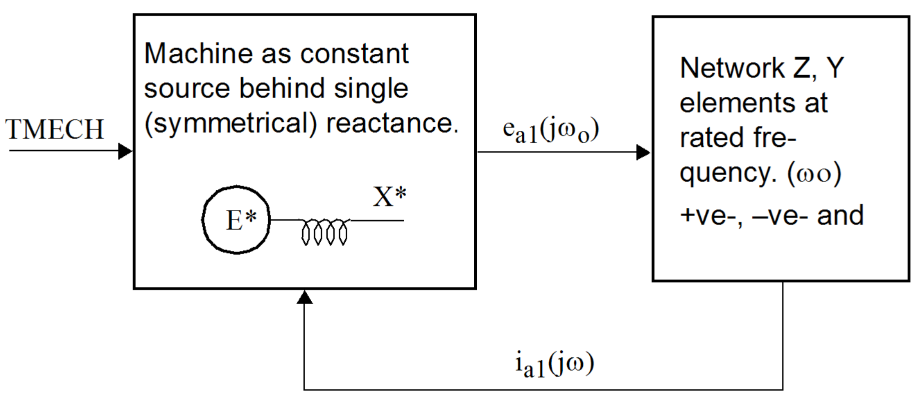


Figure 1.8. Classical Representation of Source Behind Reactance

The base level of system representation assumed in all following discussion is that shown in Figure 1.5, “Network Differential Equations”. This level of machine and transmission system modeling is needed to handle the majority of transient and asymptotic [1] stability problems that arise in the planning and design of modern systems. The practical implementation of such modeling involves the construction and integration of the large set of differential and algebraic equations describing:

- Each major rotating machine.
- Generator excitation controls.
- Turbines and their governing systems.
- The transmission network.
- Loads as perceived at bulk transmission substations.

All of these elements are modeled by the nonlinear differential equations describing variations of rotor angular position, of generator internal flux linkages, and of control signals. Dynamic phenomena within the first three elements are of prime interest.

1.2.3. Calculations to Use the Model

The transmission network and bulk loads are modeled by the set of simultaneous linear algebraic equations expressing Kirchhoff's laws for the network, and the voltage/current/power characteristics of the loads.

A representative power system model used in the current practice of utilities in the United States might involve 5000 network nodes (buses), 8000 network branches, 2500 bulk loads, and 1000 generating units.

The simulation model of such a system would require approximately:

5000

Simultaneous complex algebraic equations for the network modeling.

2500

Nonlinear load boundary condition equations.

1000

Equivalent network sources (Thevenin or Norton) to represent generator internal voltages.

14000

Coupled, simultaneous, nonlinear differential equations governing the variations of 14000 state variables, to model the generating units and their controls.

Such a model is useful only when the engineer has a tool for the mathematical solution of this huge set of equations.

The process of solving the algebraic equations for given loads and generator power outputs is referred to as the *Power Flow Calculation*. It requires an iterative procedure. There are several alternative iteration schemes, all of which produce a solution in the form of a stated magnitude and phase angle of the power frequency

[1] Transient stability is the ability of a *generator* to remain in synchronism by surviving the first swing of a disturbance. Asymptotic stability is the ability of the *system as a whole* to return to a given steady-state equilibrium after being moved away from it by a small perturbation.

voltage phasor for each node. The process of integrating the differential equations to produce plots of the transient variation of quantities such as rotor angle or power flow (as functions of time) is called Dynamic Simulation. Both Power Flow and Dynamic Simulation calculations are handled in the computer by the Power System Simulation Program, PSS®E.

The Dynamic Simulation calculation is often referred to, in error, as a Transient Stability or Stability calculation, a misinterpretation of the meaning of the term stability. The correct interpretation is that the stability or instability of a power system, with respect to a suitably defined criterion, can be determined by engineering analysis of the results of one or more dynamic simulation calculations.

1.3. PSS®E Files

1.3.1. File Classifications

The principal file used by PSS®E is its *working file*, which corresponds directly to the display register of the hand-held calculator. It would be possible to execute complete simulations with PSS®E using only the working file and question and answer dialog. This would be inefficient, however, because even the smallest simulations require quite large volumes of data. The normal use of PSS®E, therefore, involves interactive dialog with the user for commands and the handling of small amounts of data, with all activities that use large volumes of data reading from and writing to files rather than the interactive work station. The files associated with PSS®E are discussed in detail in File System Overview of the *PSS®E Program Operation Manual*.

To use the material in this Application Guide the user must recognize the characteristics of the PSS®E file classes, which are summarized in Table 1.2, "PSS®E File Classes".

Table 1.2. PSS®E File Classes

File Class	Created By	Type	Accessible To
Working files	PSS®E	Binary	PSS®E
Data input files	User via text editor, or auxiliary program	ASCII	PSS®E and user
Output listing files	PSS®E	ASCII	User
Channel output files	PSS®E	Binary	PSS®E and auxiliary programs
Response files	User via text editor	ASCII	PSS®E and user
Saved case and snapshot files	PSS®E	Binary	PSS®E

1.3.2. Working Files

All PSS®E activities operate on the working files. These may be visualized as a complete power system model that the engineer is operating by the execution of PSS®E activities. The working files are an integral part of the PSS®E package. Users never need to reference these files by name, but must be aware that they are processing these files every time they use PSS®E. The names and general functions of the working files are as follows:

FMWORK

Working file for all operations involving the factorized system admittance matrix.

SCWORK

Working file for fault analysis.

DSWORK

Scratch file for dynamic simulation activities.

These names are reserved and must not be assigned by the user to any other files.

The contents of working files FMWORK, SCWORK and DSWORK are variable depending upon the recent sequencing and context of activity executions. Users of PSS®E do not need to be concerned with the specific contents of these files as long as they observe the prerequisites listed in Appendix A of the *PSS®E Program Operation Manual* for each activity.

1.3.3. Data Input Files

PSS®E must, from time to time, accept large volumes of data from external sources. Such data could be typed directly into the PSS®E working files by means of input activities accessible from the File menu. This practice is unacceptable, however, and voluminous data are best assembled in an Input Data File independently of PSS®E and before PSS®E is started up. This file may then be used as the input source for PSS®E to feed data through the appropriate input activity into the PSS ®E working files.

Certain data processing activities of PSS®E, such as those from the File menu, can create data input files for subsequent rereading by other PSS®E activities. Data files created by PSS®E activities are used principally in transferring power system models between the PSS®E databases in the computers of different utility companies.

Reading data from input data files should be a relatively infrequent occurrence in PSS®E. After an initial working case has been built in the PSS®E working files, the input data files should be set aside and all data changes and small additions should be made directly on the working cases with the PSS®E data handling activities such as those found in the Edit menus. Attempts to keep a large input data file up-to-date with an ongoing power system study are usually both error-prone and time-consuming. PSS®E saved cases, as described below, are a far more efficient format for maintaining the power flow and system database of a study.

1.3.4. Output Listing Files

The majority of PSS®E report generating activities, such as those found in the List or Report menus, may write their output to the user terminal, directly to a printing unit, or to a named file. If the user requests output to a named file that already exists, the report is written into that file in exactly the same format as if it was being printed directly. If the file requested by the user does not exist, it is created immediately by the output activity. When written, the output file is available to all standard file manipulation functions; it may be printed, transferred to disk or CD, examined with the text editor, or discarded.

The user may instruct PSS®E to create as many output files as wanted. It is good practice, however, to limit the number of output files because they use a large amount of disk storage capacity. Output files should be dumped from disk to magnetic tape or CD for archival purposes and used in future PSS®E reports.

1.3.5. Channel Output Files

Channel output files are produced by the PSS®E dynamic simulation activities. They are named and created by activities found in the simulation menu of the dynamics activity selector. These activities run initiation of the simulations in response to a user name specification and receive the values of the PSS ®E output channels at regular time intervals during a simulation. Unlike output listing files, channel output files are of binary type and cannot be intelligibly printed by standard file management functions of the computer. Rather, the channel output files are organized as required to enter into the channel output file processing program PSSPLT.

1.3.6. Saved Case and Snapshot Files

Because the activities always operate on the same group of working files, it is necessary to load the required working case and other system data into these files before starting any sequence of simulation work. While it would be possible to load the working files on a routine basis by using those activities found in the File menu to read input data files, this would be grossly inefficient, as input data files are organized for people and must be reorganized by the reading activities to match the computational organization of PSS®E. Furthermore, this method would require continuous updating of the input data files to ensure that the problem data is available for future use.

PSS®E overcomes these problems by using SAVED CASE and SNAPSHOT files. These files are binary images of the working files. To conserve disk space, saved case files are compressed in the sense that they do not record unoccupied parts of the working file when the working case is smaller than the capacity limit of the program.

The PSS®E activity Save in the File menu power flow activity selector allows the user to record the present condition of the power flow working file for future reference. The recording of the working file is accomplished by making an exact image of its contents in binary form on the saved case file. The user can return to any previous stage of work by restoring the saved case image to the working file with the Open in the File menu of the power flow activity selector.

Saved case files made with Save As record all positive-, negative-, and zero-sequence data as used in all aspects of system simulation including power flow, optimal power flow, fault analysis, equivalent construction, and dynamic simulation work.

The part of the working file pertaining to the modeling of equipment dynamics, as distinct from the transmission network model, may be recorded by the execution of activity Save As in the File menu of the dynamic activity selector, which makes a binary image of all dynamic modeling data in a snapshot file. A snapshot may be returned to the working file by Open in the File menu of the dynamic activity selector.

Because they are binary images of the working file, saved case and snapshot files cannot be examined or listed directly by the computer's editor or file utilities. The procedure for examining these files is to return the one to be examined to the PSS®E working file with File>Open..., and to obtain a formatted data listing with a PSS®E reporting functions.

The user is responsible for ensuring that SAVED CASE and SNAPSHOT FILES that are needed for future reference will not be overwritten.

1.4. Structure of PSS®E

The organization of PSS®E, shown in Figure 1.9, "PSS®E Program Structure", operates like a very large and sophisticated hand-held calculator: The user supplies the intelligence needed to select the number and keystroke sequence; the calculator provides the processing power to perform functions on the number. In the case of PSS®E, the display register is replaced by a large *working file* containing a complete positive-, negative-, zero-sequence and dynamics representation of the user's power system; the mathematical functions (keys) of the calculator are replaced by power system analyses functions such as iterate power flow, advance time simulation, or summarize line overloads. Each functional activity of PSS®E corresponds to calculator function keys. Each activity runs a self-contained and distinct operation using the working file. The iterate power flow activity, for example, adjusts bus voltages in order to satisfy Kirchhoff's laws and load conditions but otherwise leaves the working file unchanged. The user is responsible for ensuring that the working file contains appropriate data before initiating any activity.

The working database maintains complete symmetrical component networks and dynamics models to represent a power system where maximum capacities are as specified in Table 1.3, "Program Maximum Capacities".

The PSS®E program may be operated in either interactive or automation mode. In the interactive mode, activities are initiated by the user from pull-down menus on the PSS®E graphical user interface. The main PSS®E window is shown in Figure 1.10, "PSS®E Graphical User Interface (Power Flow)". Each activity is run immediately. When any activity has ended, either by completion or due to an abnormal condition, control is returned to the master program module. Each activity carries on its own dialog with the user, may read input data from data storage files or from the console, and may generate tabular and/or graphic output at the screen, in a file, or on a printing device.

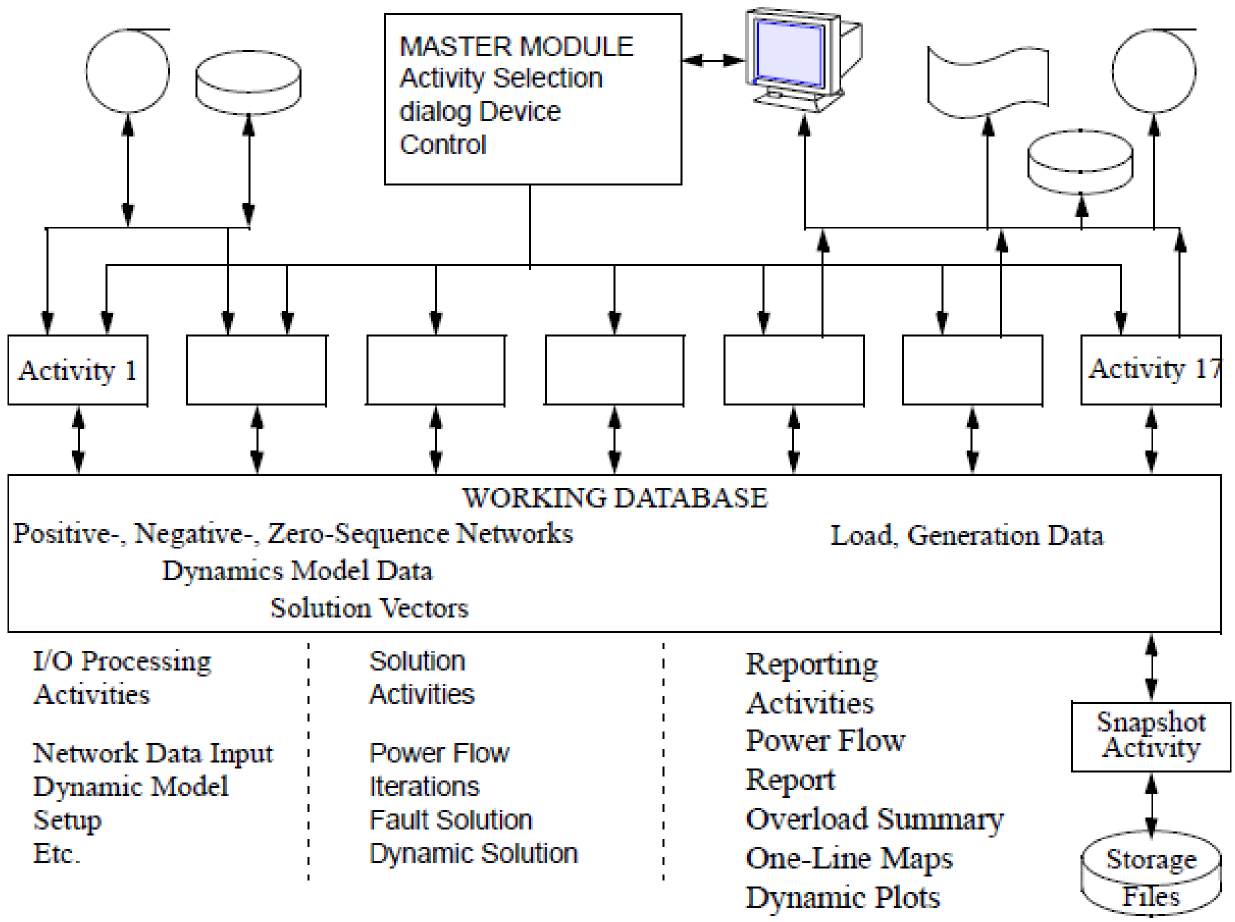


Figure 1.9. PSS®E Program Structure

Table 1.3. Program Maximum Capacities

Power Flow Activities	
Buses	200,000
Loads	300,000
Generating Buses	26,840
Generators	33,050
Branches	300,000
Transformers	60,000
dc Transmission Links	50
Interchange Areas	1,200
Zero-Sequence Mutual Couplings	4,000
Zones	2,000
Owners	1,200
Dynamic Simulation Activities	
Buses	200,000

Dynamic Simulation Activities	
Machines	33,050
Branches	300,000
Transformers	60,000
State Variables	257,900
Constants	515,800
Variables	206,300
Output Channels	66,110
ICONs	257,900

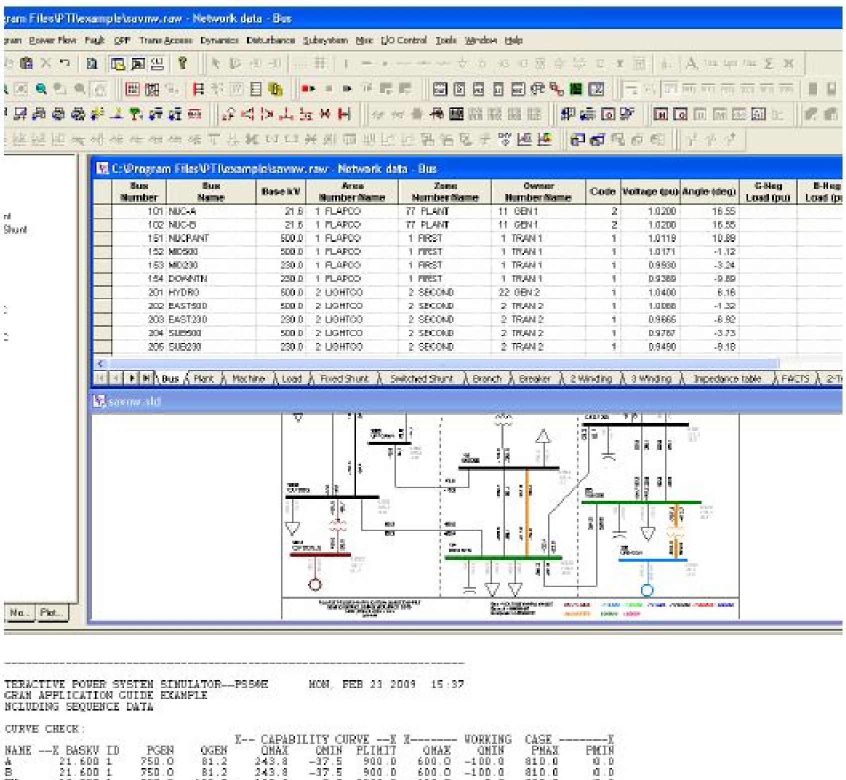


Figure 1-10. PSS®E Graphical User Interface (Power Flow)

Figure 1.10. PSS®E Graphical User Interface (Power Flow)

The alternative control mode of PSS®E is the simple batch mode. In this mode, the commands and data that would normally be entered by the user in interactive mode are preset by the user in a batch input file. The batch input file is called a *response file*. When initiated in batch mode, PSS®E takes its commands and input from the response file, executing the same functionality as it would in the interactive mode except for a different input sequence.

PSS®E execution has an internal macro-scheduling capability that allows routine job steps to be handled in batch mode while the engineer fully controls critical setup and decision-making steps in interactive mode.

1.5. The Power System Simulator, PSS®E

This manual is intended to illustrate the correct procedures for formulating power system performance problems for simulation by the PSS®E programs, and for interpreting the results of PSS®E simulations. The reader should become familiar with the general structure of PSS®E before proceeding.

PSS®E is a system of programs and structured data files designed to handle the basic functions of power system performance simulation work, namely,

- Data handling, updating, and manipulation.
- Power Flow.
- Fault Analysis.
- Dynamic Simulation + Extended Term Simulation.
- Equivalent Construction.

The PSS®E program is based on the engineering philosophy that all power system simulations should use the best possible modeling of all items of equipment. The selection of equipment models was strongly biased by computing equipment limitations during the early development of power system simulation. Many simulation programs used equipment models that were characterized more by their ability to fit within specific computer constraints or their compatibility with given mathematical techniques than by their engineering accuracy.

Modern computer developments have virtually eliminated the predominance of computational considerations in selecting equipment models. Computer memory addressing capability is now unlimited; furthermore, the combination of paged memory systems and low semiconductor memory costs now allows computers to be dedicated to the simulation function and to run several major system simulation jobs simultaneously. Now, the governing factors in selecting equipment models are:

1. Understanding of the physical processes inherent in each item of equipment and their effect on behavior as observed from the power system.
2. Availability of adequately accurate data.

Accordingly, the design of PSS®E is determined by modeling criteria; mathematical techniques and database structure follow, rather than dictate, decisions on equipment representation.

The steps in using PSS®E to simulate a power system and investigate its performance are:

1. Examine or design the physical equipment (transmission lines, generators, relays, governors, etc.) that make up the simulation and decide on the correct equations and parameter values to represent them.
2. Transfer the physical model for the system into the form of a PSS®E input data file referring to interconnected models of individual buses, branches, generators, etc. Use equivalent branches and dummy buses, as necessary, to make up equivalent circuits for equipment that is not handled by an explicit model in PSS®E.
3. Use the PSS®E programs to process the data, apply calculations, and print reports.
4. Interpret the calculation results in terms of the indicated physical behavior of the equipment with which the process was started in the first step.

It is too easy for the power system analyst to become obsessed with the second and third steps, at the expense of only cursory, and even erroneous, treatment of the first and fourth. This book intends to emphasize the importance of the first and fourth step.

Chapter 2
Transmission Lines

2.1. Long Lines at Varying Frequency

2.1.1. Frequency Dependence of Transmission Line Equivalent Circuit

The transmission line equivalent circuit shown in Figure 2.17, "Pi-Form Transmission Line Equivalent Circuit" and Figure 2.18, "Exact Equivalent of Circuit of Transmission Line of Length, *L*, at One Frequency" is said to be exact in that its terminal current and voltage solution corresponds exactly to the solution of the transmission line partial differential equations for a given frequency. The equivalent circuit is exact only at a single frequency, however, and only approximates the solution of the partial differential equations as frequency deviates from the nominal value.

The range of frequency of interest in the majority of system performance studies is 55 to about 75 Hz. System frequency may fall as low as 55 Hz in emergency situations where a section of the system is separated from the remainder and has a deficiency of generation. Frequencies as high as 75 Hz can occur in the transmission leading from remote hydroelectric systems when they are disconnected from their load by the opening of long interconnecting lines at their receiving ends.

Assume that the inherent per-mile line resistance, inductance, and shunt capacitance are constant over the above frequency range, although these parameters are not constants over broad frequency ranges because of variation in the depth of penetration of ground currents and because of conductor skin effect. Assuming constant inherent line parameters allows the per-mile sequence impedances and admittances, as used in Section 2.8, "Transmission Line Symmetrical Component Equivalent Circuits" and Section 2.5, "Transmission Line Constants Programs", to be written as

$$Z(j\omega) = R_s + j\omega L_s \text{ (ohms)} \tag{2.1}$$

$$Y(j\omega) = j\omega C_s \text{ (micromhos)} \tag{2.2}$$

where R_s, L_s and C_s are the per-mile values of the inherent positive-, negative-, or zero-sequence line parameters.

A short transmission line where the exact and approximate equivalent-circuit parameters are very nearly equal could be modeled satisfactorily by the equivalent circuit shown in Figure 2.1, "Equivalent Circuit for a Short Transmission Line Over Restricted Frequency Baud above Rated Frequency". A long transmission line cannot be represented by an equivalent circuit of the type shown in Figure 2.1, "Equivalent Circuit for a Short Transmission Line Over Restricted Frequency Baud above Rated Frequency" because the behavior of Z_{ex} and Y_{ex} of a long line do not correspond to constant values of R_s, L_s, and C_s, even for the narrow frequency band under consideration here.

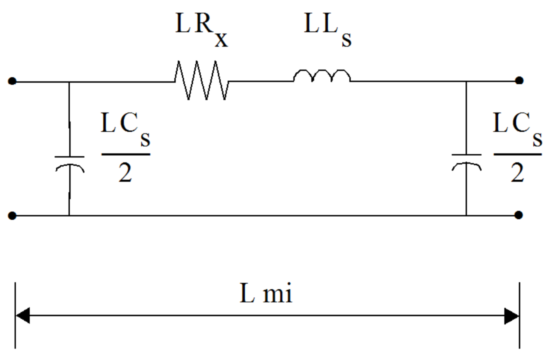


Figure 2.1. Equivalent Circuit for a Short Transmission Line Over Restricted Frequency Baud above Rated Frequency

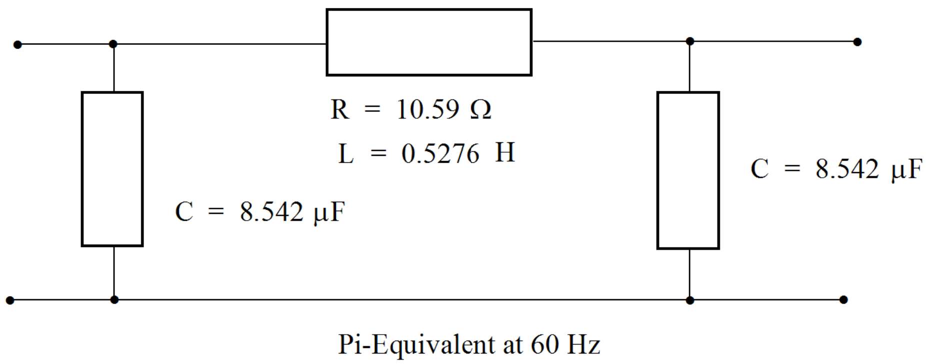
The exact parameters, Z_{ex} and Y_{ex}, of the equivalent circuit shown in Figure 2.17, "Pi-Form Transmission Line Equivalent Circuit"and Figure 2.18, "Exact Equivalent of Circuit of Transmission Line of Length, *L*, at One Frequency" may be written as

$$Z_{ex} = R_{ex} + j\,\omega\,L_{ex} \text{ (ohms)} \tag{2.3}$$

$$Y_{ex} = j\,\omega\,C_{ex} \text{ (micromhos)} \tag{2.4}$$

The parameters R_{ex}, L_{ex}, and C_{ex} are not constants; they vary quite significantly as frequency is varied over the range of interest here, with the variation becoming stronger as line length is increased.

Figure 2.2, "Exact Pi-Equivalent Circuits for 400-Mile Length of Example Transmission Line at 60 and 65 Hz (Skin Effect Neglected)" considers a 400-mile length of the example line of Figure 2.7, "TMLC Calculations for Basic Symmetrical Component Transmission Line Properties (Sheet 1 of 2)" and Figure 2.9, "Use of TMLC to Calculate Equivalent-Circuit Data for a Line of Finite Length"; it shows the exact pi-equivalent parameters for frequencies of 60 and 65 Hz.



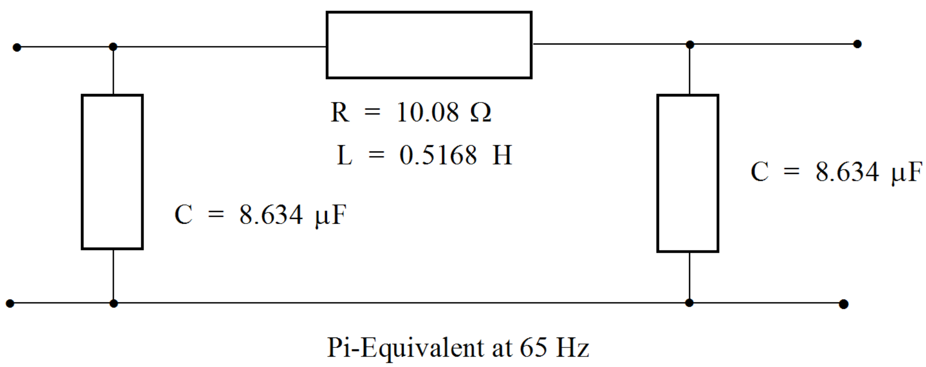


Figure 2.2. Exact Pi-Equivalent Circuits for 400-Mile Length of Example Transmission Line at 60 and 65 Hz (Skin Effect Neglected)

Figure 2.3, "Difference Between 60 and 65 Hz Values of R_{ex}, L_{ex}, and C_{ex} as a Function of Line Length" shows the percentage difference between the 60 and 65 Hz values of R_{ex}, L_{ex}, and C_{ex} of the line as its length is increased through the practical range. Apparently, the use of constant effective resistance, inductance, and capacitance values in the pi-equivalent circuit is reasonable for line sections up to about 100 miles long, but longer lines are not properly represented by an equivalent with constant resistance, inductance, and capacitance.

Length (mi)	Difference,%		
	ΔR	ΔL	ΔC
10	0	0	0
50	0.07	0	0.02
100	0.25	0.14	0.06
200	1.02	0.52	0.25
300	2.42	1.14	0.58
400	4.67	2.09	1.07
500	8.23	2.55	1.75

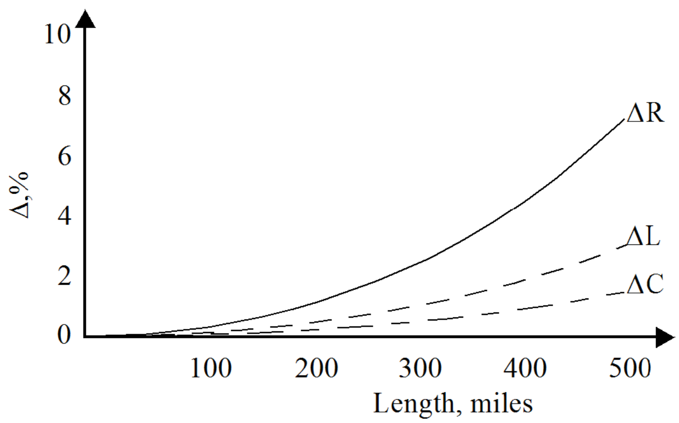


Figure 2.3. Difference Between 60 and 65 Hz Values of R_{ex}, L_{ex}, and C_{ex} as a Function of Line Length

2.1.2. Line Sections in Series

The receiving-end conditions of a line are related to those at the sending-end as shown in Equation 2.56 in Section 2.8.3, “Exact Sending- and Receiving-End Equivalent Circuit”. Consider a long line, as shown in Figure 2.4, “Long Transmission Line Broken into Four Short Sections for Analysis over a Range of Frequencies”, to be divided into a number of identical sections, and compute the *A*, *B*, *C*, and *D* constants from Equation 2.52 through Equation 2.55 for the section length.

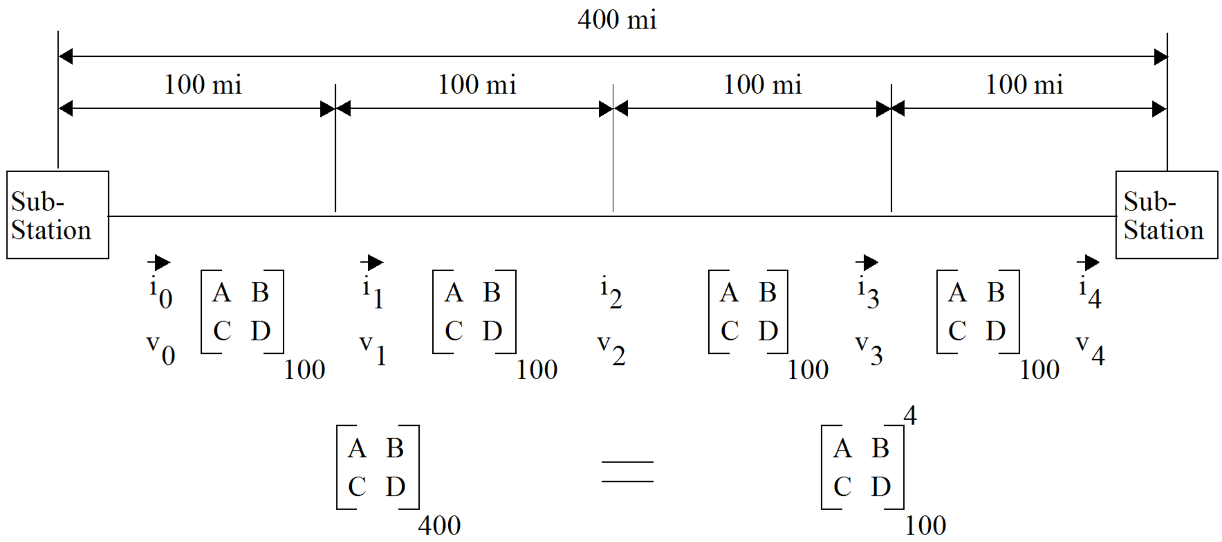


Figure 2.4. Long Transmission Line Broken into Four Short Sections for Analysis over a Range of Frequencies

Then the conditions at point 1 are given by

$$\begin{bmatrix} v_1 \\ i_1 \end{bmatrix} = \begin{bmatrix} A & B \\ C & D \end{bmatrix} \begin{bmatrix} v_0 \\ i_0 \end{bmatrix} \tag{2.5}$$

and those at point 2 are given by

$$\begin{aligned} \begin{bmatrix} v_2 \\ i_2 \end{bmatrix} &= \begin{bmatrix} A & B \\ C & D \end{bmatrix} \begin{bmatrix} v_1 \\ i_1 \end{bmatrix} \\ &= \begin{bmatrix} A & B \\ C & D \end{bmatrix}^2 \begin{bmatrix} v_0 \\ i_0 \end{bmatrix} \end{aligned} \tag{2.6}$$

Therefore, a line may be described by

$$\begin{aligned} \begin{bmatrix} v_r \\ i_r \end{bmatrix} &= \begin{bmatrix} A & B \\ C & D \end{bmatrix} \begin{bmatrix} v_s \\ i_s \end{bmatrix} \\ &= \begin{bmatrix} A_n & B_n \\ C_n & D_n \end{bmatrix}^n \begin{bmatrix} v_s \\ i_s \end{bmatrix} \end{aligned} \tag{2.7}$$

where A, B, C, and D describe the full length of the line and A_n, B_n, C_n, and D_n are computed as the exact solution for one *nth* of the line.

The exact equivalent circuit of Figure 2.17, “Pi-Form Transmission Line Equivalent Circuit” and Figure 2.18, “Exact Equivalent of Circuit of Transmission Line of Length, *L*, at One Frequency” was derived to give a voltage and current solution corresponding exactly to that expressed in terms of A, B, C, and D for a given frequency. Equation Equation 2.7 shows, therefore, that the single pi-equivalent circuit of Figure 2.17, “Pi-Form Transmission Line Equivalent Circuit” and Figure 2.18, “Exact Equivalent of Circuit of Transmission Line of Length, *L*, at One Frequency” can be replaced exactly by a number of pi-equivalents of identical form connected in series (Figure 2.5, “Use of Multiple Pi-Sections in Series to Achieve the Same Effect as a Single Pi-Section”).

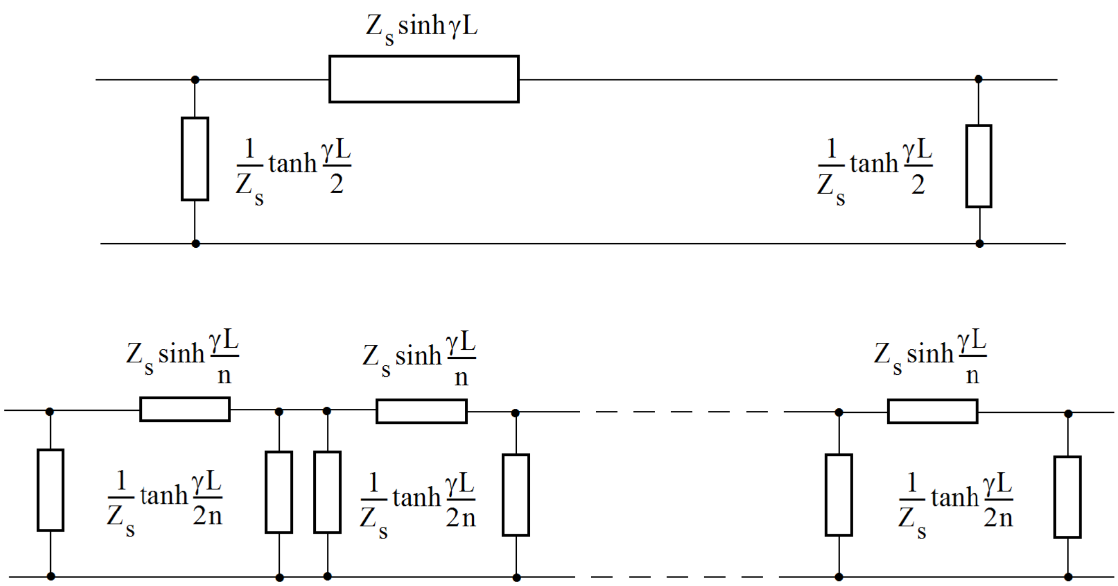


Figure 2.5. Use of Multiple Pi-Sections in Series to Achieve the Same Effect as a Single Pi-Section

Each of the series-connected pi-equivalents has parameters given, according to Equation 2.61, Equation 2.62 or Equation 2.63,Equation 2.64 by

$$Z_{ex} = z_s \sinh\frac{\gamma L}{n} = \frac{ZL}{n}\,\frac{\sinh\frac{\gamma L}{n}}{\frac{\gamma L}{n}} \tag{2.8}$$

$$Y_{ex} = \frac{2}{z_s}\tanh\frac{\gamma L}{2n} = \frac{YL}{n}\,\frac{\tanh\frac{\gamma L}{2n}}{\frac{\gamma L}{2n}} \tag{2.9}$$

The use of multiple pi-equivalents in series is exact at the frequency for which the inherent line parameters were calculated, and furthermore, more accurate than the use of a single pi-equivalent circuit at frequencies other than the base value. Figure 2.3, “Difference Between 60 and 65 Hz Values of R_{ex}, L_{ex}, and C_{ex} as a Function of Line Length” shows that there is effectively no change in the values of R_{ex}, L_{ex}, and C_{ex} with frequency when they correspond to a line-length of 50 miles or less. Therefore, representing a long transmission line by a number of short sections is desirable in any study where operation at off-nominal frequency is to be considered.

2.2. Summary of Transmission Line Data Calculation

A typical series of steps to use in calculating data to represent a transmission line in system performance studies follows:

1. Determine the spatial disposition of phase and shield wire conductors from the tower profile.

2. Determine all conductor types; estimate conductor sags and earth resistivity.

3. Use program TMLC to determine the positive- and zero-sequence values of per-mile line series impedance, *Z*, and line shunt impedance, (1/*Y*).

4. Compute the series impedance and shunt admittance as follows:

   a. If the line length, *L*, is very short (less than about 50 miles), use TMLC and Equation 2.30, Equation 2.31 to compute the overall series impedance and shunt admittance for both positive- and zero-sequence.

   b. If the line length, *L*, exceeds about 50 miles and studies will be concerned only with nominal frequency operation, use program TMLC to compute the overall sequence series impedance and shunt admittances according to Equation 2.63, Equation 2.64.

   c. If the line is long and studies are considering operation at off-nominal frequency, select a number of line sections, with each section being less than about 50 miles long. Compute the section sequence series impedance and shunt admittance with program TMLC. Note, with the data, the number of pi-equivalents with these impedance and admittance values that must be connected in series to represent the full length of the transmission line.

2.3. Symmetrical Component Representation

2.3.1. The Symmetrical Component Transformation

Simulation of a power system under the most general conditions of operation, where there is significant asymmetry in the elements of the *z* matrix of Equation 2.32 for each branch, would require every branch to be characterized by Equation 2.32 and Equation 2.33. This, in turn, would lead to a set of 3*N* simultaneous linear equations for the description of a system of *N* buses.

Such completely general solutions are seldom necessary because a power system is normally designed to be basically symmetrical with respect to its three phases. The immediate temptation might be to analyze one phase only, relying completely on symmetry for recognition of the other two phases. Such an approach is valid only for items of equipment where, in addition to being symmetrical, the voltages induced in each phase are functions of the current in that phase only. This is true for some transformers and loads but is not true in general because, as indicated in Equation 2.32, the voltage drop in one phase of a transmission line is normally a function of the currents in all three phases.

The most common way to take advantage of the phase symmetry of the power system is based on the *symmetrical component transformation*, which is given by

$$\begin{bmatrix} i_a \\ i_b \\ i_c \end{bmatrix} = \begin{bmatrix} 1 & 1 & 1 \\ 1 & a^2 & a \\ 1 & a & a^2 \end{bmatrix} \begin{bmatrix} i_0 \\ i_1 \\ i_2 \end{bmatrix}$$

$$\begin{bmatrix} v_0 \\ v_1 \\ v_2 \end{bmatrix} = 1/3 \begin{bmatrix} 1 & 1 & 1 \\ 1 & a & a^2 \\ 1 & a^2 & a \end{bmatrix} \begin{bmatrix} v_a \\ v_b \\ v_c \end{bmatrix} \tag{2.10}$$

where *a* is the complex number (-0.5 + j0.866) = e

$$^{+j\frac{2\pi}{3}}$$

.

2.3.2. Source Voltages in Symmetrical Components

The immediate importance of the symmetrical component transformation is seen by noting that the normal power system voltage source, the forward rotating synchronous generator, produces a balanced set of phase voltages

Substituting Equation 2.11 into Equation 2.10 and noting the identity

$$v_a = v\sin(\omega t + \phi) = Ve^{j(\omega t + \phi)}$$

$$v_b = v\sin\left(\omega t + \phi - \frac{2\pi}{3}\right) = Ve^{j\left(\omega t + \phi - \frac{2\pi}{3}\right)}$$

$$v_c = v\sin\left(\omega t + \phi - \frac{4\pi}{3}\right) = Ve^{j\left(\omega t + \phi - \frac{4\pi}{3}\right)} \tag{2.11}$$

$$e^{jk} + e^{j\left(k - \frac{2\pi}{3}\right)} + e^{j\left(k - \frac{4\pi}{3}\right)} = 0$$

shows that, for the balanced voltages of Equation 2.11, the corresponding symmetrical component voltages are

$$\begin{bmatrix} v_0 \\ v_1 \\ v_2 \end{bmatrix} = \begin{bmatrix} 0 \\ Ve^{j\omega t} \\ 0 \end{bmatrix} \tag{2.12}$$

Following the same procedure for a backward rotating synchronous generator would show the symmetrical component voltages to be

$$\begin{bmatrix} v_0 \\ v_1 \\ v_2 \end{bmatrix} = \begin{bmatrix} 0 \\ 0 \\ Ve^{j\omega t} \end{bmatrix} \tag{2.13}$$

Finally, assuming all three-phase voltages to be identical, $v_a = v_b = v_c = Ve^{j\omega t}$, would produce the symmetrical component voltages

$$\begin{bmatrix} v_0 \\ v_1 \\ v_2 \end{bmatrix} = \begin{bmatrix} Ve^{j\omega t} \\ 0 \\ 0 \end{bmatrix} \tag{2.14}$$

Because v_1 would be produced by a normally rotating generator, it is referred to as the *positive-sequence voltage*. Correspondingly, because v_2 would be produced by either rotating the generator in the reverse direction or by reversing two of its phase connections, it is referred to as the *negative-sequence voltage*. The *zero-sequence voltage* component is v_0.

The only voltage sources produced by the generators of a power system are balanced three-phase sets of forward phase rotation. Correspondingly, analysis in terms of symmetrical components encounters nonzero source voltages only in the positive sequence.

2.3.3. Branch Impedances in Terms of Symmetrical Components

By expressing the transmission branch impedance Equation 2.32 in the compact form

$$\underline{v_p} = \underline{z_{pp}}\,\underline{i_p} \tag{2.15}$$

and the symmetrical component transformations in the forms

$$\underline{i_p} = \underline{T} \bullet \underline{i_s} \tag{2.16}$$

and

$$\underline{v_s} = \frac{1}{3}\underline{T}^* \ \underline{V_p} \tag{2.17}$$

then it is possible to derive a symmetrical component equation corresponding to Equation 2.32 by substituting Equation 2.16 and Equation 2.15 into Equation 2.17 as follows

$$\begin{aligned} \underline{v_s} &= \frac{1}{3}\underline{T}^* \ \underline{Z_{pp}}\,\underline{i_p} \\ &= \frac{1}{3}\underline{T}^* \ \underline{Z_{pp}}\,\underline{T i_s} \end{aligned} \tag{2.18}$$

when

$$\underline{v_s} = \underline{Z_{ss}}\,\underline{i_s} \tag{2.19}$$

where

$$\underline{Z_{ss}} = \frac{1}{3}\underline{T}^* \ \underline{Z_{pp}}\,\underline{T} \tag{2.20}$$

In general, Z_{ss} is fully populated just as Z_{pp} is. The great advantage of the symmetrical component method arises, however, when it is applied to equipment that is constructed in such a way that all phases appear to be electrically identical. This condition exists for many transformers, motors, passive loads (e.g., lighting), and for some special classes of transmission line construction. The three phases are approximately identical in the great majority of transmission lines and other transmission components. When all three phases of equipment are electrically identical, the nine elements of the Z_{pp} matrix are related by the equalities:

$$Z_{aa} = Z_{bb} = Z_{cc} = Z_p \tag{2.21}$$

$$Z_{ab} = Z_{bc} = Z_{ca} = Z_m \tag{2.22}$$

The Z_{pp} matrix is then given by

$$\underline{Z_{pp}} = \begin{bmatrix} Z_p & Z_m & Z_m \\ Z_m & Z_p & Z_m \\ Z_m & Z_m & Z_p \end{bmatrix} \tag{2.23}$$

and application of Equation 2.20 gives the symmetrical component impedance matrix as

$$\underline{Z_{ss}} = \begin{bmatrix} Z_p + 2Z_m & 0 & 0 \\ 0 & Z_p - Z_m & 0 \\ 0 & 0 & Z_p - Z_m \end{bmatrix} \tag{2.24}$$

Thus, for the symmetrical equipment or transposed transmission line, the symmetrical component equation corresponding to Equation 2.32 is

$$\begin{bmatrix} V_{0s} - V_{0r} \\ V_{1s} - V_{1r} \\ V_{2s} - V_{2r} \end{bmatrix} = \begin{bmatrix} Z_{00} & Z_{01} & Z_{02} \\ Z_{10} & Z_{11} & Z_{12} \\ Z_{20} & Z_{21} & Z_{22} \end{bmatrix} \begin{bmatrix} i_0 \\ i_1 \\ i_2 \end{bmatrix} \tag{2.25}$$

where

$$Z_{00} = Z_p + 2Z_m \tag{2.26}$$

$$Z_{11} = Z_{22} = Z_p - Z_m \tag{2.27}$$

Equation Equation 2.25 shows the principal value of the symmetrical component transformation. When it is applied to the voltages, currents, and branches of a power system in which all branches are either of symmetrical construction or transposed, the voltages developed in each individual sequence are functions of the current in that sequence only.

It is usually reasonable to assume that every branch of a power transmission system is symmetrical as long as no unbalanced faults are present. In this case, every system element is described by equations with the form of Equation 2.25 and, because source voltages exist only in the positive sequence, nonzero currents exist only in the positive sequence. As a result, the system analysis can be based on the positive sequence only.

For balanced conditions, then, conventional practice is to represent each transmission line by the positive-sequence equation

$$\Delta v_1 = Z_{11} i_1$$

and each set of balanced three-phase voltages by a single positive-sequence voltage. As shown by Equation 2.12, the positive-sequence voltage has the same magnitude and phase position as the a-phase member of the balanced three-phase set.

2.4. The Power System Network

The fundamental process of interest in power system analysis is the flow of power along transmission lines. The most basic problem facing power system engineers is the determination of the power flow along the individual lines of a network when specified amounts of power are injected by generators and withdrawn by loads. This analysis is a steady-state calculation in which all voltages and currents are sinusoidal and may be described by complex variables associated with phasors rotating at power frequency.

The analysis of a network of transmission lines requires a method of solving for the voltages and currents at all points in a network built up by the interconnection of many such transmission line equivalent circuits. Given these elements, the engineer can calculate the conditions that would exist at any point on a real transmission network for a proposed set of loads and generator outputs.

2.5. Transmission Line Constants Programs

2.5.1. Program TMLC

The modeling of a transmission line requires two processes: first, the calculation of the inherent series impedance and shunt admittance matrices for an incremental length of its set of conductors, and, second, the derivation of sequence equivalent circuits of the finite-length line from the incremental length impedance and admittance. These calculations are handled by the Transmission Line Constants' Program, TMLC.

2.5.2. Basic Transmission Line Properties

Program TMLC takes input data specifying the positions of the line conductors at their tower support points. It computes the phase impedance matrix of Equation 2.32, the phase admittance matrix of Equation 2.33, and the sequence impedance and admittance matrices of Equation 2.36 through Equation 2.41. TMLC recognizes the effects of conductor bundling, overhead shield wires, variable penetration of earth current into the ground as frequency and earth resistivity are varied, and conductor sag.

The basic results of TMLC are the full matrices of Equation 2.32 and Equation 2.33. In the most frequent use of TMLC, these matrices are distilled to a single value of self-impedance and self-admittance for each sequence, with the sequence-to-sequence impedances and admittances being ignored.

Figure 2.6, "345-kV Line Cross Section" shows a typical conductor spatial layout for a 345-kV transmission line. Figure 2.7, "TMLC Calculations for Basic Symmetrical Component Transmission Line Properties (Sheet 1 of 2)" shows the terminal dialog from a run in which TMLC was used to compute the line's inherent symmetrical component impedance and admittance properties. The output matrices printed by TMLC are the sequence series impedance matrix, Z_{ss}, and the *inverse* of the sequence admittance matrix, Y_{ss}. Series impedances are expressed in ohms/mile, and shunt impedances are given in megohm/mile.

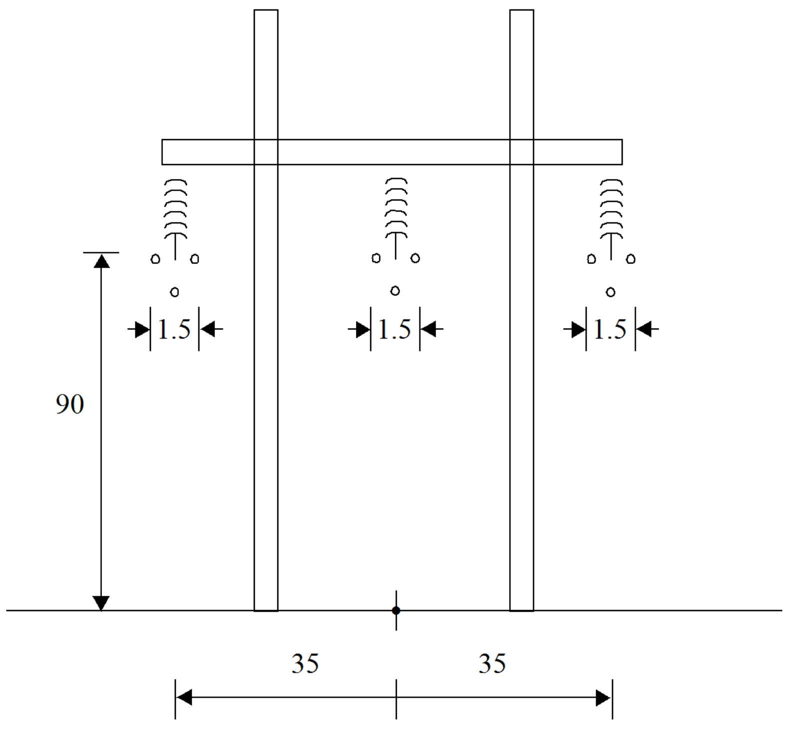


Figure 2.6. 345-kV Line Cross Section

The value of the line property, *Z*, as used in Equation 2.44 is the appropriate diagonal term of the series impedance matrix printed by TMLC. The value of the line property, *Y*, as used in Equation 2.45, is the reciprocal of the appropriate diagonal term of the shunt impedance matrix printed by TMLC. For example, the positive-sequence properties of this line are

$$Z = 0.03324 + j0.55799 \text{ ohms/mile} \tag{2.28}$$

$$Y = j1.0/0.13174 = j7.59 \text{ micromho/mile} \tag{2.29}$$

Examination of the off-diagonal terms of the matrices in Figure 2.7, "TMLC Calculations for Basic Symmetrical Component Transmission Line Properties (Sheet 1 of 2)" shows that they are small in relation to the diagonal terms. Therefore, two assumptions are reasonable: these terms are negligible and the line behaves as if it is fully transposed.

```
                          POWER TECHNOLOGIES, INC.
                      TRANSMISSION LINE CHARACTERISTICS
                              PROGRAM VER III          11-28-89

 ENTER 1 FOR TERMINAL INPUT, 0 FOR DATA FILE INPUT: 1
 INPUT TITLE (60 CHAR MAX)
 ************************************************************
345 kv line without shield wires
 ENTER NUMBER OF CIRCUITS: 1
 ENTER NUMBER OF SHIELD WIRE TYPES: 0
 FOR CIRCUIT NUMBER    1  ENTER
      NUMBER OF CONDUCTORS/BUNDLE: 3
      CONDUCTOR NAME: rail
 ENTER CONDUCTOR SAG(POSITIVE VALUE MEASURED FROM CABLE CLAMP): 45

 BUNDLE IS ASSUMED TO HAVE THE FOLLOWING CONFIGURATION


       THREE CONDUCTOR BUNDLE

             BUNDLE LOCATION SPECIFIED AT +
            /
           /
     C    +    C
                     C-CONDUCTOR
                     B-BUNDLE SPACING

     *    C    *
     *         *
     *         *
     *<-- B -->*


      BUNDLE SPACING: 1.5
 ALL CIRCUIT AND SHIELD WIRE LOCATIONS SHOULD BE
     SPECIFIED FROM BASE OF TOWER OF CIRCUIT 1
      BUNDLE CONDUCTOR LOCATION (VER,HOR)
        PHASE A: 90 -35
        PHASE B: 90 0
        PHASE C: 90 35
 ENTER OUTPUT OPTION.
        0-NO MORE OUTPUT, EXIT PROGRAM
        1-FULL IMPEDANCE MATRIX
        2-FULL SYMMETICAL COMP. MATRIX
        3-ABBREVIATED SYMM. COMP.
        4-SUMMARIZED RESULTS DATA FILE
        5-POWER FLOW
        6-SHORT CIRCUIT
        7-LIST OUT DATA
        8-WRITE INPUT DATA FILE
        9-CHANGE DATA
       10-CHANGE OUTPUT DEVICE
       11-ANOTHER CASE WITH NEW DATA: 9
ENTER CHANGE CODE:
 0 = NO MORE CHANGES      1 = CONDUCTOR DATA
 2 = SHIELD WIRE DATA     3 = TITLE
 4 = OTHER DATA: 4
          FREQUENCY(HZ),EARTH RESISTIVITY(OHMS),OUTPUT UNITS
              60.00          100.00                F
 ENTER NEW FREQUENCY(HZ),EARTH RESISTIVIY(OHMS),OUTPUT UNITS: ,75
      NEW FREQUENCY(HZ),EARTH RESISTIVITY(OHMS),OUTPUT UNITS
              60.00           75.00                F
```

Figure 2.7. TMLC Calculations for Basic Symmetrical Component Transmission Line Properties (Sheet 1 of 2)

```
 ENTER CHANGE CODE:
0 = NO MORE CHANGES      1 = CONDUCTOR DATA
2 = SHIELD WIRE DATA     3 = TITLE
4 = OTHER DATA: 0
ENTER OUTPUT OPTION.
       0-NO MORE OUTPUT, EXIT PROGRAM
       1-FULL IMPEDANCE MATRIX
       2-FULL SYMMETICAL COMP. MATRIX
       3-ABBREVIATED SYMM. COMP.
       4-SUMMARIZED RESULTS DATA FILE
       5-POWER FLOW
       6-SHORT CIRCUIT
       7-LIST OUT DATA
       8-WRITE INPUT DATA FILE
       9-CHANGE DATA
      10-CHANGE OUTPUT DEVICE
      11-ANOTHER CASE WITH NEW DATA: 2

                           POWER TECHNOLOGIES, INC.
                       TRANSMISSION LINE CHARACTERISTICS
                               PROGRAM VER III          11-28-
89

                   345 KV LINE WITHOUT SHIELD WIRES
    *SEQUENCE PARAMETERS*
       Z SERIES-11-MATRIX
           (OHMS/MI)


    0.30461    0.02417   -0.02424
    2.03083   -0.01404   -0.01392

   -0.02424    0.03324   -0.04837
   -0.01392    0.55799    0.02808

    0.02417    0.04850    0.03324
   -0.01404    0.02785    0.55799

            X0/X1= 3.640

       Z SHUNT-11-MATRIX
           (MOHM-MI)


    0.00000    0.00501   -0.00501
    0.22695   -0.00289   -0.00289

   -0.00501    0.00000   -0.01003
   -0.00289    0.13174    0.00579

    0.00501    0.01003    0.00000
   -0.00289    0.00579    0.13174

            X0/X1= 1.723
```

Figure 2.8. TMLC Calculations for Basic Symmetrical Component Transmission Line Properties (Sheet 2 of 2)

2.5.3. Equivalent Circuit of Finite Transmission Line

For a short transmission line it is quite satisfactory to use the approximations

$$Z_{ex} \approx Z_{series}L \text{ (ohms)} \tag{2.30}$$

$$Y_{ex} \approx \frac{L}{Z_{shunt}} \text{ (micromhos)} \tag{2.31}$$

where Z_{series} and Z_{shunt} are diagonal elements of the series and shunt impedance matrices printed out by TMLC and L is the length of the line.

For line lengths exceeding 75 miles, the simple multiplication of inherent per-mile line properties by line length is inadequate and the exact line length corrections described in Section 2.8.3, “Exact Sending- and Receiving-End Equivalent Circuit” should be used. Program TMLC allows these corrections and can provide output of the exact equivalent- circuit parameters corresponding to Figure 2.18, “Exact Equivalent of Circuit of Transmission Line of Length, *L*, at One Frequency”. For the example of Figure 2.7, “TMLC Calculations for Basic Symmetrical Component Transmission Line Properties (Sheet 1 of 2)”, the propagation constant from Equation 2.48, Equation 2.28, and Equation 2.29 is

$$\begin{aligned} \gamma &= \sqrt{(0.03358 + j0.55799 * j7.59 \times 10^{-6}} \\ &= 0.0001 + j0.0021 \end{aligned}$$

With a line length of 200 miles, the series impedance, Z_{ex} from Equation 2.61, is

$$\begin{aligned} Z_{ex} &= (0.03358 + j0.55799) * 200 * \frac{\sinh(0.02 + j0.42)}{(0.02 + j0.42)} \\ &= 6.3416 + j108.4189 \text{ ohms} \end{aligned}$$

For comparison, the approximate series impedance based on the inherent per-mile impedance alone is

$200 * (0.03358 + j0.55799) = 6.716 + j111.598$ ohms

Recognizing the base impedance for 100 MVA and 345 kV as 1190 ohms gives the exact per-unit value of Z_{ex} for the example line as

$Z_{ex} = 0.0053 + j0.0911$ per unit

Figure 2.9, “Use of TMLC to Calculate Equivalent-Circuit Data for a Line of Finite Length” shows the continuation of the example TMLC dialog to calculate the exact positive- and zero-sequence pi-equivalent parameters.

```
ENTER OUTPUT OPTION.
       0-NO MORE OUTPUT, EXIT PROGRAM
       1-FULL IMPEDANCE MATRIX
       2-FULL SYMMETICAL COMP. MATRIX
       3-ABBREVIATED SYMM. COMP.
       4-SUMMARIZED RESULTS DATA FILE
       5-POWER FLOW
       6-SHORT CIRCUIT
       7-LIST OUT DATA
       8-WRITE INPUT DATA FILE
       9-CHANGE DATA
      10-CHANGE OUTPUT DEVICE
      11-ANOTHER CASE WITH NEW DATA: 6


DEFAULT IS 100 MVA, DO YOU WANT TO CHANGE IT?
FOR EACH CIRCUIT ENTER KV
      FOR CIRCUIT 1
        ENTER KV: 345
FOR EACH CIRCUIT ENTER SELF CIRCUIT LENGTH
AND LENGTH IN COMMON WITH OTHER CIRCUITS
IN MILES (DEFAULT COMMON LENGTH IS 0.0)
  CIRCUIT 1
      ENTER SELF LENGTH: 200

                           POWER TECHNOLOGIES, INC.
                       TRANSMISSION LINE CHARACTERISTICS
                               PROGRAM VER III          11-28-89

                      345 KV LINE WITHOUT SHIELD WIRES
                          BASE MVA IS   100.00

                      ***********HYPERBOLIC CORRECTION APPLIED*************
                      ****************IN PU - TOTAL LENGTH*****************
SELF TO               ****POSITIVE SEQUENCE****   ******ZERO SEQUENCE******
CKT  CKT  KV   LNTH(MI)   R         X        B         R         X        B

 1        345. 200.000  0.00527  0.09114  1.83294   0.04524  0.32168  1.08135

ENTER OUTPUT OPTION.
       0-NO MORE OUTPUT, EXIT PROGRAM
       1-FULL IMPEDANCE MATRIX
       2-FULL SYMMETICAL COMP. MATRIX
       3-ABBREVIATED SYMM. COMP.
       4-SUMMARIZED RESULTS DATA FILE
       5-POWER FLOW
       6-SHORT CIRCUIT
       7-LIST OUT DATA
       8-WRITE INPUT DATA FILE
       9-CHANGE DATA
      10-CHANGE OUTPUT DEVICE
      11-ANOTHER CASE WITH NEW DATA: 0
```

Figure 2.9. Use of TMLC to Calculate Equivalent-Circuit Data for a Line of Finite Length

Figure 2.10, "Difference Between Exact and Approximate Line Impedance Components for Transmission Line Shown in Figure 2.7, "TMLC Calculations for Basic Symmetrical Component Transmission Line Properties (Sheet 1 of 2)"" shows the effect of the hyperbolic corrections of Equation 2.61, Equation 2.62 and/or Equation 2.63, Equation 2.64 on the positive-sequence impedance of the sample line as its length is increased. It is readily apparent that the exact expressions, Equation 2.61, Equation 2.62 or Equation 2.63, Equation 2.64, should be used if the line is longer than about 200 miles. It is notable that the error in series resistance exceeds that in both series reactance and shunt susceptance.

The importance of using correct transmission line data is readily apparent in a consideration of losses. Although it is not printed by TMLC in Figure 2.9, "Use of TMLC to Calculate Equivalent-Circuit Data for a Line of Finite Length" because it is usually neglected, the real part of the exact shunt susceptance of the example line is 1.3345 micromhos. This would give a shunt power loss at rated voltage of

Δ P = 3 × V^2 (2G $_{ex}$)

= 6 × 345000^2 × 1.3345 × 10^{-6}

= 0.95 MW

Length (mi)	Difference,%		
	ΔR	ΔX	ΔB
10	0	0	0
50	0.35	0.18	0
100	1.43	0.71	0.35
200	5.90	2.87	1.42
300	14.09	6.62	3.20
400	27.33	12.21	5.71
500	48.34	20.03	8.98

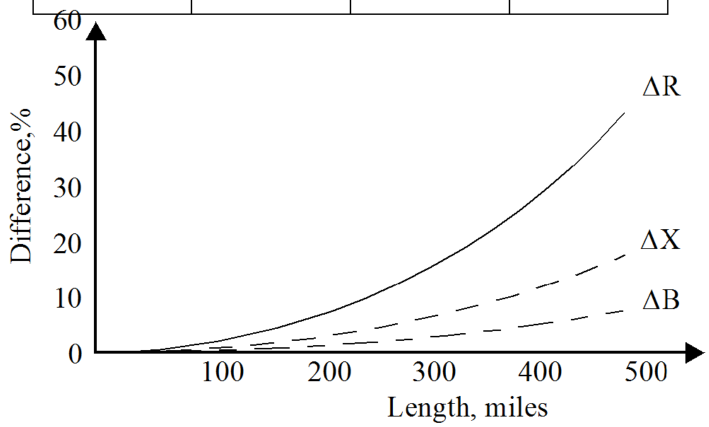


Figure 2.10. Difference Between Exact and Approximate Line Impedance Components for Transmission Line Shown in Figure 2.7, "TMLC Calculations for Basic Symmetrical Component Transmission Line Properties (Sheet 1 of 2)"

The change in series resistive losses, due to neglect of the hyperbolic correction terms at a typical load current of 1500 A, would be

Δ P = $3I^2$ Δ R

= 3 × 1500^2* (6.3416 - 6.716)

= -2.53MW

It is normal practice, in analyses at power frequency, to ignore the shunt conductance, G_{ex}. The above example shows that the error in line losses due to this practice is considerably less than the error that would be incurred by neglecting the hyperbolic correction terms in calculating the series impedance.

2.6. Transmission Line Series Impedance

Power flows along a transmission line when a difference between the voltages at its two ends forces current to flow along its phase conductors. The basic characterization of a transmission line is, therefore, a set of impedances relating end-to-end phase voltage differences to phase currents.

The calculation of transmission line parameters starts with the specification of the line's spatial cross section as shown, for example, in Figure 2.11, "Example Transmission Line Cross Section".

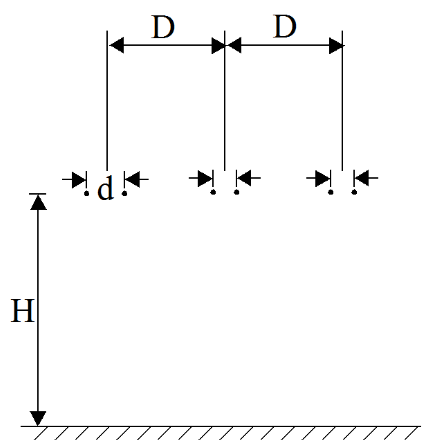


Figure 2.11. Example Transmission Line Cross Section

Given this cross section, a Transmission line Constants' Program may be used to calculate the flux linking each conductor when a specified current is passed, in turn, down each conductor. This calculation is based upon the standard solution of Maxwell's equations for the magnetic field surrounding a long straight current-carrying conductor; that is, on the Biot-Savart equation

$$B(r) = \frac{\mu_o I}{2\pi r}$$

where

B(r)

Flux density in the direction tangential to the conductor, in the plane of its cross section at radius, *r*.

I

Current in the conductor.

μ_o

Permeability of free space.

The output of the basic flux linkage calculation is a series impedance matrix, expressed in ohms/kilometer, relating voltage drop along a section of each phase of a line section, as shown in Figure 2.12, “Voltage Drop Along a Section of Transmission Line”, to the current in each phase. Note that the line constants' calculation normally assumes that the individual conductors of a bundle are bonded together at frequent intervals, and presents outputs as if each phase is a single equivalent conductor carrying the entire phase current.

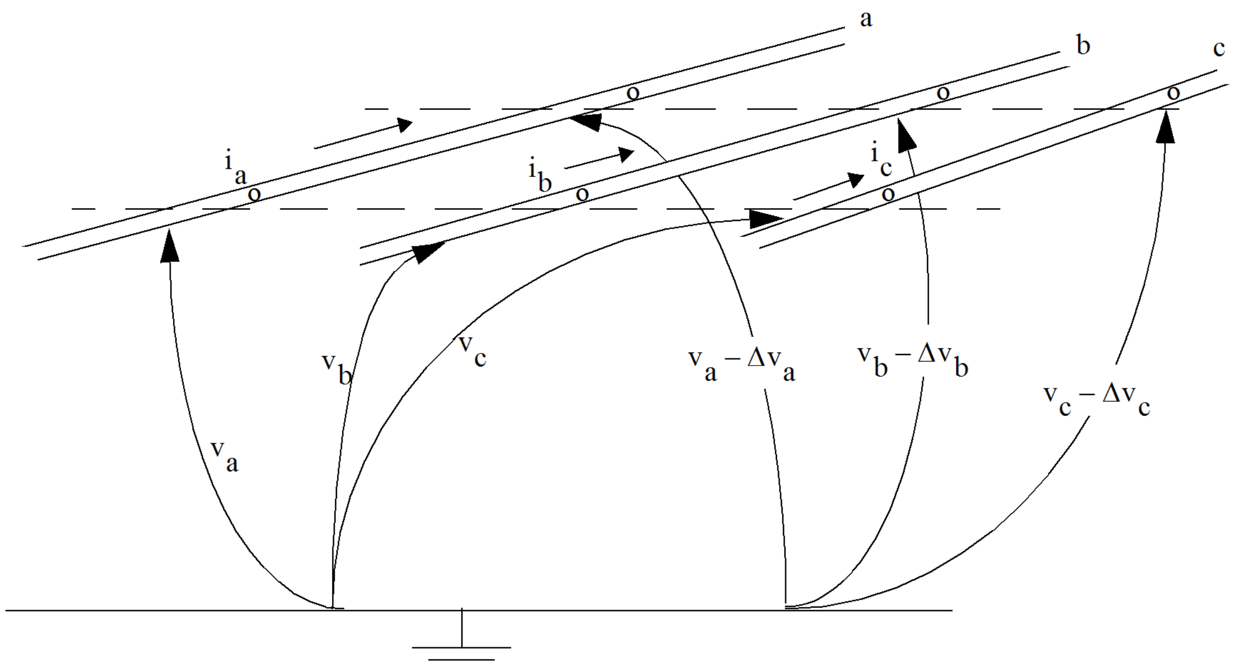


Figure 2.12. Voltage Drop Along a Section of Transmission Line

The impedance matrix defines the voltage drop relationship as

$$\underset{\text{volts/km}}{\begin{bmatrix} \Delta v_a \\ \Delta v_b \\ \Delta v_c \end{bmatrix}} = \underset{\text{ohms/km}}{\begin{bmatrix} z_{aa} & z_{ab} & z_{ac} \\ z_{ba} & z_{bb} & z_{bc} \\ z_{ca} & z_{cb} & z_{cc} \end{bmatrix}} \underset{\text{amps}}{\begin{bmatrix} i_a \\ i_b \\ i_c \end{bmatrix}} \tag{2.32}$$

Because the total flux linkage of each conductor in the line is a function of the current in every conductor, the impedance matrix of Equation 2.32 is fully populated. Furthermore, because the line cross section is not symmetrical with respect to all phases and ground, all of its elements may be different.

It is important to note that the elements of the series impedance matrix have the form $R + jX$ corresponding to an inductance with series resistance. The imaginary part of each element is calculated with respect to a stated frequency, (normally 50 or 60 Hz) and all elements of the series impedance matrix, both resistance and reactance, change as frequency is changed. For small variations of frequency, it is reasonable to assume that the real part of each element is constant, and that the imaginary part is proportional to frequency. This assumption is not valid for wide frequency variations because increased frequency reduces the penetration of earth return currents into the ground and can cause significant changes in the effective resistances of the line.

2.7. Transmission Line Shunt Capacitance

All conducting bodies suspended in space establish capacitance between one another. The conductors of a transmission line are no exception, and the capacitances between the phases and ground are significant. As a result, significant currents flow from the transmission line conductors-to-ground and from phase-to-phase during normal operation.

The capacitances of the line may be calculated on a per-kilometer basis by a solution of the electrostatic field equations, given the line cross section as shown in Figure 2.11, "Example Transmission Line Cross Section". The result of this calculation is a shunt admittance matrix defining the shunt charging currents defined in Figure 2.13, "Charging Current of a Transmission Line".

Equation Equation 2.33 shows the voltage-to-charging current relationship after calculating the nominal frequency admittance corresponding to each capacitance element:

$$\underset{\text{amps/km}}{\begin{bmatrix} \Delta i_a \\ \Delta i_b \\ \Delta i_c \end{bmatrix}} = \underset{\text{mhos/km}}{\begin{bmatrix} B_{aa} & B_{ab} & B_{ac} \\ B_{ba} & B_{bb} & B_{bc} \\ B_{ca} & B_{cb} & B_{cc} \end{bmatrix}} \underset{\text{volts}}{\begin{bmatrix} v_a \\ v_b \\ v_c \end{bmatrix}} \tag{2.33}$$

Because charging current flows from phase-to-phase as well as from phase-to-ground, the admittance matrix of Equation 2.33 is fully populated. Again, because transmission layouts are not necessarily symmetrical, all of the elements may be different.

Because leakage resistances from transmission line conductors-to-ground are essentially infinite, the charging current is purely capacitive. The elements of the shunt admittance matrix are therefore directly proportional to frequency.

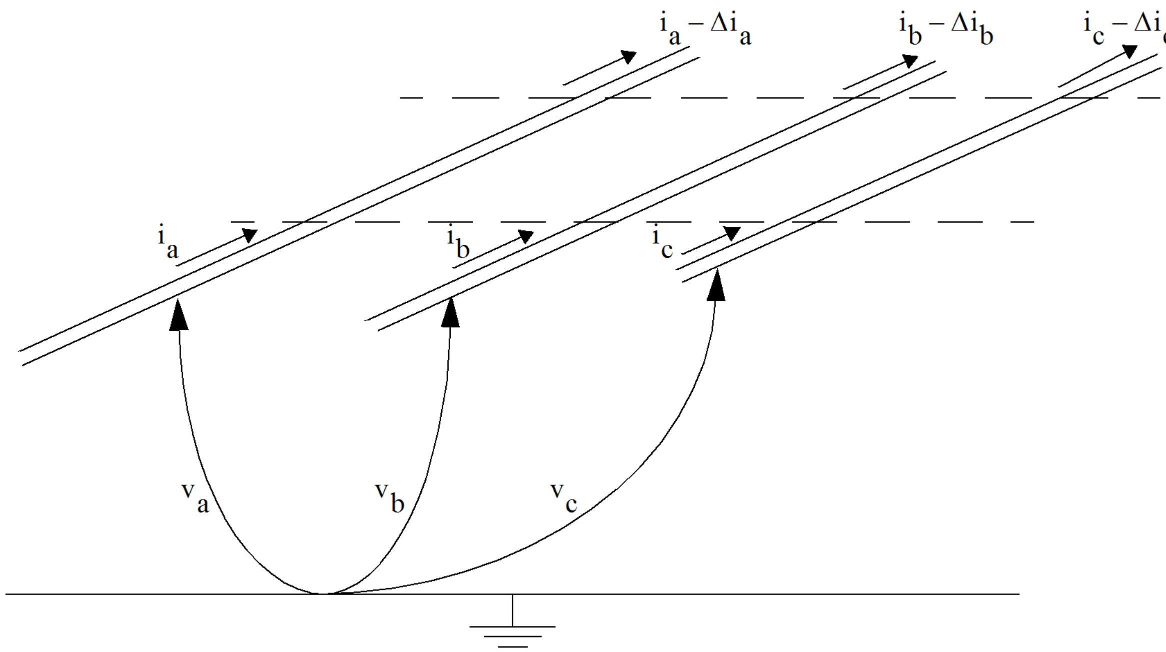


Figure 2.13. Charging Current of a Transmission Line

2.8. Transmission Line Symmetrical Component Equivalent Circuits

The preceding sections showed how to obtain the basic series impedance and shunt admittance characteristics of a transmission line from the spatial arrangement of conductors. These basic characteristics do not describe the overall behavior of a transmission line because they apply to an elemental line section in which all phase currents and voltages are constant. The voltages and currents in a real line are not constant along its length. This section describes the relationship between the basic line characteristics, Equation 2.32 and Equation 2.33, and the overall line behavior as observed at its end points.

2.8.1. Transmission Line Differential Equation

Equations Equation 2.32 and Equation 2.33 describe the behavior of any small elemental length, Δl, of line as shown in Figure 2.14, "Voltage and Current Change in Elemental Transmission Line Segment". The variation in amplitude and phase of sinusoidal currents and voltages over the elemental length may be approximated by

$$\Delta v_p = -Z_{pp} i_p \Delta l \tag{2.34}$$

$$\Delta i_p = -Y_{pp} v_p \Delta l \tag{2.35}$$

where Z_{pp} and Y_{pp} are the impedance and admittance matrices of Equation 2.32 and Equation 2.33 expressed in ohms or mhos/kilometer, and Δl is expressed in kilometers.

Because the majority of this work will be in terms of symmetrical components, it is most useful to transform Equation 2.34 and Equation 2.35 symmetrical component matrices, Z_{ss} and Y_{ss}, to be negligible. In this case, the line element is described by

$$\Delta v_1 = -Z_{11} i_1 \Delta l \tag{2.36}$$

$$\Delta i_1 = -Y_{11} v_1 \Delta l \tag{2.37}$$

$$\Delta v_2 = -Z_{22} i_2 \Delta l \tag{2.38}$$

$$\Delta i_2 = -Y_{22} v_2 \Delta l \tag{2.39}$$

$$\Delta v_0 = -Z_{00} i_0 \Delta l \tag{2.40}$$

$$\Delta i_0 = -Y_{00} v_0 \Delta l \tag{2.41}$$

Each of the three sequences may now be handled independently by consideration of its own pair of equations; i.e., drop the subscripts 1, 2, 0 and consider the general equations

$$\Delta v = -Z i \Delta l \tag{2.42}$$

$$\Delta i = -Y v \Delta l \tag{2.43}$$

where

v

Sequence voltage with respect to ground.

i

Sequence current with respect to ground.

Z

Sequence series impedance in ohms/kilometer.

Y

Sequence shunt admittance in ohms/kilometer.

Δ l

Elemental length in kilometers.

The analysis starts by allowing Δ l to become infinitesimally small so that the line behavior is given by the differential equations

$$\frac{dv}{dx} = -Zi \tag{2.44}$$

$$\frac{di}{dx} = -Yv \tag{2.45}$$

The solution of this pair of differential equations must give a relationship between the sending and receiving end voltages and currents as defined in Figure 2.14, “Voltage and Current Change in Elemental Transmission Line Segment”.

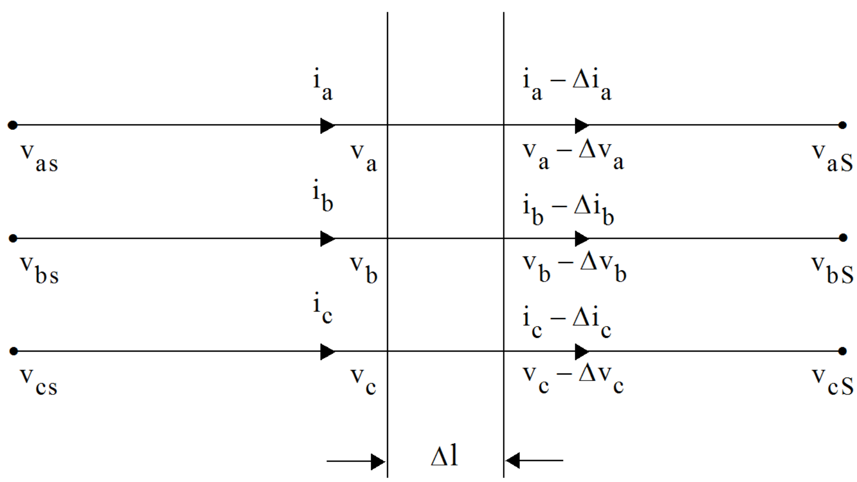


Figure 2.14. Voltage and Current Change in Elemental Transmission Line Segment

2.8.2. Voltage Profile on Long Transmission Lines

The solution of Equation 2.44 and Equation 2.45 for the current and voltage at any distance, *x*, from the sending end of the line is

$$v(x) = \frac{[v(0) - z_S i(0)]}{2} e^{\gamma x} + \frac{[v(0) - z_S i(0)]}{2} e^{-\gamma x} \qquad (2.46)$$

$$i(x) = \frac{[v(0) - z_S i(0)]}{2z_S} e^{\gamma x} + \frac{[v(0) - z_S i(0)]}{2z_S} e^{-\gamma x} \qquad (2.47)$$

where

$\gamma = \sqrt{ZY}$ is the propagation constant (2.48)

and

$z_S = \sqrt{Z / Y}$ is the surge impedance (2.49)

The propagation constant, γ, and surge impedance, z_S, are fundamental properties of a transmission line. They depend only upon its per-kilometer values of series impedance and shunt admittance and are independent of the length of the line.

Each term of the solution Equation 2.46 specifies the variation of a voltage phasor as a function of distance down the line. Because γ is a complex number, ($\gamma = \alpha + j\beta$), the amplitude and phase of this phasor vary as shown in Figure 2.15, "Variation of Voltage Along a Long Transmission Line". The distance, $2\pi / \beta$, over which the position of this phasor is rotated by 2π radians, is called the wavelength of the line voltage profile. Because both components of the voltage solution Equation 2.46 may be present on the line, the actual voltage amplitude is not attenuated uniformly with distance as suggested by Figure 2.15, "Variation of Voltage Along a Long Transmission Line". A realistic profile of voltage amplitude with distance down the line is shown in Figure 2.16, "Standing Wave Profile of Sinusoidal Voltage Amplitude on Long Transmission Line". The voltage amplitude will, in general, exhibit a sequence of maxima and minima with pairs of maxima being separated by a distance of $2\pi / \beta$ kilometers. This profile of amplitude of the sinusoidal voltage, as shown in Figure 2.16, "Standing Wave Profile of Sinusoidal Voltage Amplitude on Long Transmission Line", is called a voltage standing wave, and the distance, $2\pi / \beta$, is called the wavelength of the line.

A 230-kV transmission line, for example, might have positive-sequence 60-Hz basic parameters of

- Series impedance, *Z*, = 0.07 + *j*0.5 ohms/kilometer.
- Shunt admittance, *Y*, = *j*3.5 micromho/kilometer.

For this line, then,

$$\begin{aligned}\gamma &= \sqrt{ZY} = \sqrt{(0.07 + j0.5) \times j3.5 \times 10^{-6}} \\ &= (0.092 + j1.33) \times 10^{-3} \\ &= \alpha + j\beta\end{aligned}$$

$$z_s = \sqrt{Z / Y} = \sqrt{\frac{0.07 + j0.5}{j3.5 + 10^{-6}}}$$

$$= \sqrt{(0.143 - j0.02) \times 10^6}$$

$$= 377.8 - j26.3 \text{ ohms}$$

From the value of γ , it is apparent that the wavelength of the voltage standing wave is

$$\frac{2\pi}{\beta} = \frac{2\pi}{1.33 \times 10^{-3}} = 4740 \text{ kilometers (2960 miles)}$$

Power transmission practice is based on lines operating with nearly constant voltage over their full length. A practical upper limit on the length of transmission line that can be used without special voltage correction measures, then, is about one-tenth of a wavelength (500 kilometers).

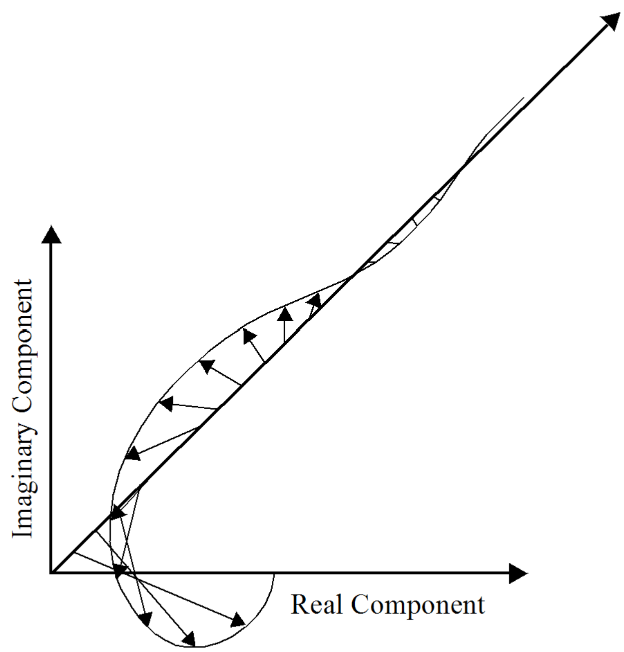


Figure 2.15. Variation of Voltage Along a Long Transmission Line

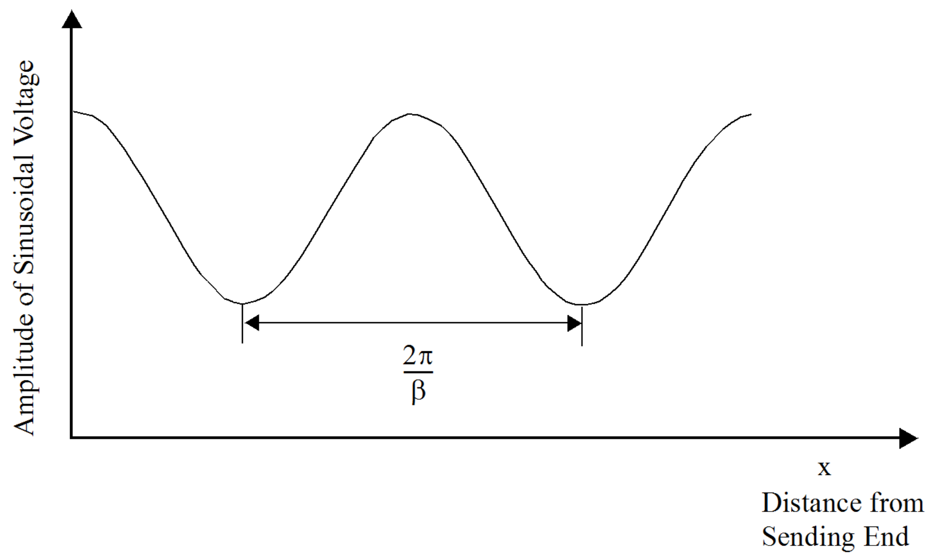


Figure 2.16. Standing Wave Profile of Sinusoidal Voltage Amplitude on Long Transmission Line

2.8.3. Exact Sending- and Receiving-End Equivalent Circuit

The majority of this simulation analysis will be concerned with conditions at the ends of the transmission line, rather than with the details of conditions along its length. The derivation of a terminal model for a line is facilitated by rearranging Equation 2.46 and Equation 2.47 to relate the conditions at sending and receiving ends. The notation corresponding to Figure 2.14, “Voltage and Current Change in Elemental Transmission Line Segment”:

$v(0)$

v_s, sending end voltage

$v(L)$

v_r, receiving end voltage

$i(0)$

i_s, sending end current

$i(L)$

i_r, receiving end current

where L is the length of the line.

The equations Equation 2.46 and Equation 2.47 can be manipulated into the form

$$v_r = Av_s + Bi_s \quad (2.50)$$

$$i_r = Cv_s + Di_s \quad (2.51)$$

where

$$A = \cos h\, \gamma\, L \tag{2.52}$$

$$B = -Z_S \sin h\, \gamma\, L \tag{2.53}$$

$$C = (-1\,/\,Z_S) \sin\; h\, \gamma\, L \tag{2.54}$$

$$D = \cos h\, \gamma\, L \tag{2.55}$$

It is useful to note the matrix form of Equation 2.50 and Equation 2.51

$$\begin{bmatrix} V_r \\ i_r \end{bmatrix} = \begin{bmatrix} A & B \\ C & D \end{bmatrix} \begin{bmatrix} V_s \\ i_s \end{bmatrix} \tag{2.56}$$

and, later, assign the symbol, M_{rs}, to the coefficient matrix

$$M_{rs} = \begin{bmatrix} A & B \\ C & D \end{bmatrix} \tag{2.57}$$

The required equivalent circuit can now be derived by rearranging Equation 2.50 and Equation 2.51 as follows:

$$\begin{bmatrix} i_s \\ i_r \end{bmatrix} = \begin{bmatrix} \frac{-A}{B} & \frac{1}{B} \\ C - \frac{DA}{B} & \frac{D}{B} \end{bmatrix} \begin{bmatrix} V_s \\ V_r \end{bmatrix} \tag{2.58}$$

Substituting Equation 2.52 through Equation 2.55 gives

$$\begin{bmatrix} i_s \\ i_r \end{bmatrix} = \begin{bmatrix} \frac{1}{Z_s \tanh \gamma L} & \frac{-1}{Z_s \sinh \gamma L} \\ \frac{-1}{Z_s \sinh \gamma L} & \frac{1}{Z_s \tanh \gamma L} \end{bmatrix} \begin{bmatrix} V_s \\ V_r \end{bmatrix} \tag{2.59}$$

which is the admittance matrix description of the transmission line as seen from its terminals.

An equivalent circuit is now proposed of the form shown in Figure 2.17, "Pi-Form Transmission Line Equivalent Circuit", where the admittance matrix is

$$Y_{ij} = \begin{bmatrix} \left(\frac{1}{Z_{ex}} + \frac{Y_{ex}}{2}\right) & \frac{-1}{Z_{ex}} \\ \frac{-1}{Z_{ex}} & \left(\frac{1}{Z_{ex}} + \frac{Y_{ex}}{2}\right) \end{bmatrix} \tag{2.60}$$

The comparison of Equation 2.60 with Equation 2.59 and some trigonometrical manipulation yields the required result

$Z_{ex} = z_s \sinh \gamma L$ (2.61)

$$Y_{ex} = \tanh\left(\frac{\gamma L}{2}\right) \quad (2.62)$$

The exact equivalent circuit model of the transmission line (Figure 2.18, "Exact Equivalent of Circuit of Transmission Line of Length, *L*, at One Frequency") can be derived from the basic per-kilometer series impedance and shunt admittance to give an exact representation of a line of any length at a single designated frequency. Because γ is strongly dependent upon frequency and z_s may vary with frequency, this equivalent circuit is exact only at the frequency for which it was derived.

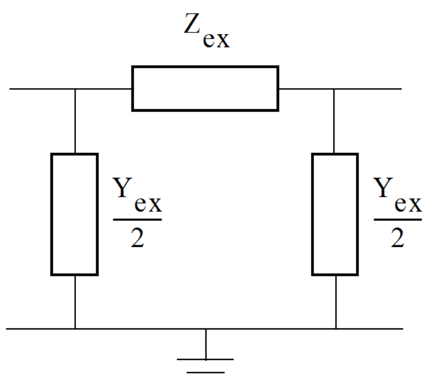


Figure 2.17. Pi-Form Transmission Line Equivalent Circuit

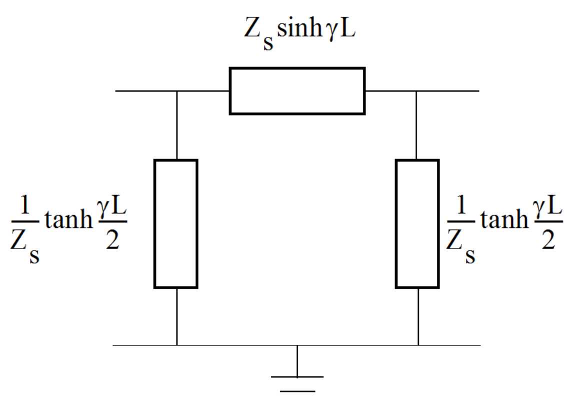


Figure 2.18. Exact Equivalent of Circuit of Transmission Line of Length, L, at One Frequency

Note from Equation 2.48 and Equation 2.49 that

$Z = \gamma z_s$

$Y = \gamma / z_s$

which may be substituted into Equation 2.61 and Equation 2.62 to give

$$Z_{ex} = ZL\frac{\sinh \gamma L}{\gamma L} \tag{2.63}$$

$$Y_{ex} = YL\frac{\tanh \frac{\gamma L}{2}}{\frac{\gamma L}{2}} \tag{2.64}$$

These results show that the series branch, Z_{ex}, of the exact equivalent circuit is equal to the total series impedance, *ZL*, of the line, multiplied by a correcting factor of (sinh $\gamma L / \gamma L$). Similarly, the total shunt admittance, Y_{ex}, of the equivalent circuit is equal to the total shunt admittance, Y*L*, of the line, multiplied by a correcting factor of (tanh ($\gamma L / 2$) / $\gamma L / 2$).The value of the correcting factors are very close to unity as long as the line length is less than about one-tenth of the line wavelength. Finally, for reference, comparison of Equation 2.60 and Equation 2.58 shows that

$$Z_{ex} = -B \tag{2.65}$$

$$\frac{Y_{ex}}{Z} = \frac{1-A}{B} \tag{2.66}$$

2.9. Transmission Lines on Shared Right-of-Way

Parallel transmission lines in close proximity on a right-of-way are characterized by mutual coupling, one-to-the-other, as well as by their individual self impedance characteristics. For example, with the two circuits shown in Figure 2.19, "Parallel 230-kV and 138-kV Circuits on the Same Right-of-Way", equations Equation 2.32 and Equation 2.33 become expanded in dimension to include the phase currents in each circuit.

$$\begin{bmatrix} \Delta V_{a230} \\ \Delta V_{b230} \\ \Delta V_{c230} \\ \Delta V_{a138} \\ \Delta V_{b138} \\ \Delta V_{c138} \end{bmatrix} = Z_{pp} \begin{bmatrix} i_{a230} \\ i_{b230} \\ i_{c230} \\ i_{a138} \\ i_{b138} \\ i_{c138} \end{bmatrix}$$

where Z_{pp} is now a 6-by-6 fully populated phase-impedance matrix. Applying the symmetrical component transformation to the matrix gives a sequence impedance equation, corresponding to Equation 2.18, that now has the following form where each of the four 3-by-3 submatrices has the form of Equation 2.23.

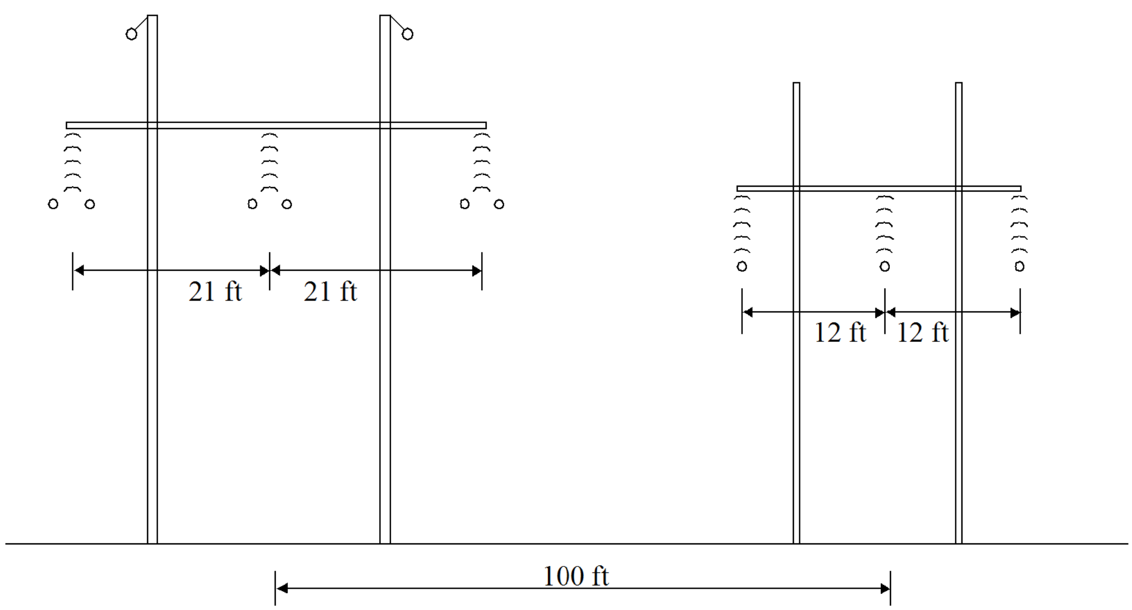


Figure 2.19. Parallel 230-kV and 138-kV Circuits on the Same Right-of-Way

$$\begin{bmatrix} \Delta V0_{230} \\ \Delta V1_{230} \\ \Delta V2_{230} \\ \Delta V0_{138} \\ \Delta V1_{138} \\ \Delta V2_{138} \end{bmatrix} = \begin{bmatrix} Z_{230,230} & Z_{230,138} \\ Z_{138,230} & Z_{138,138} \end{bmatrix} \begin{bmatrix} i0_{230} \\ i1_{230} \\ i2_{230} \\ i0_{138} \\ i1_{138} \\ i2_{138} \end{bmatrix} \tag{2.67}$$

Equation Equation 2.67 shows the matrix for the two circuits shown in Figure 2.19, "Parallel 230-kV and 138-kV Circuits on the Same Right-of-Way". The diagonal elements of the circuit self-impedance matrices $Z_{230,230}$ and $Z_{138,138}$ are dominant, allowing both to be treated as if they have the diagonal form of Equation 2.25. The only significant element of the circuit-to-circuit mutual impedance matrix is between the two zero sequences. No off-diagonal elements of the shunt impedance matrix are significant.

Chapter 3
The Per-Unit Data System

3.1. Base Value for Zero-Sequence Mutual Coupling Between Circuits

Parallel and coupled circuits on a common right-of-way are characterized by a mutual impedance in the zero sequence. The base value for this impedance, when both circuits have the same base voltage, is the same as for circuit self-impedances. When the circuits have different base voltages, the base impedance for the circuit-to-circuit zero-sequence mutual impedance depends upon both base voltages.

The mutual coupling equation in ohm units gives the zero-sequence voltage drop in a circuit 2 resulting from the zero-sequence current in a circuit 1 as

$$\Delta v_{2_0} = Z_{m_0} i_{1_0} \tag{3.1}$$

Dividing by the circuit 2 base voltage gives

$$\frac{\Delta v_{2_0}}{V_{LG\ base2}} = Z_{m_0} \frac{i_{1_0}}{I_{LG\ base1}} \times \frac{I_{LG\ base1}}{V_{LG\ base2}} \tag{3.2}$$

Combining this result with the base current definition

$$MVA_{base} = 3V_{LG\ base1}\, I_{LG\ base1} \tag{3.3}$$

gives

$$\Delta \bar{v}_{2_0} = Z_{m_0} \frac{MVA_{base}}{3V_{LG\ base1}\, V_{LG\ base2}} \bar{i}_{1_0} \tag{3.4}$$

This shows that

$$\begin{aligned} Z_{LG\ basem} &= \frac{3V_{LG\ base1}\, V_{LG\ base2}}{MVA_{base}} \\ &= \frac{V_{LL\ base1}\, V_{LL\ base2}}{MVA_{base}} \end{aligned} \tag{3.5}$$

A comparison with Equation 3.20 shows that

$$Z_{LG\ basem} = \sqrt{Z_{LG\ base1}\, Z_{LG\ base2}} \tag{3.6}$$

As an example, Figure 2.19, "Parallel 230-kV and 138-kV Circuits on the Same Right-of-Way" shows the mutual impedance between a 230-kV line and a parallel 138-kV line to be (0.2631 + *j*1.1656) ohms/mile. The base impedances relative to 100 MVA are

$$Z_{base1} = \frac{230^2}{100} = 529 \text{ ohms for 230 kV}$$

$$Z_{base2} = \frac{138^2}{100} = 190.4 \text{ ohms for 138 kV}$$

$$Z_{basem} = \frac{230 \times 138}{100} = 317.4 \text{ ohms for mutual coupling}$$

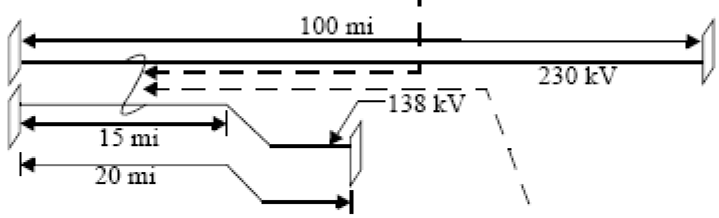
Therefore, for 20 miles of common circuit length, the zero-sequence impedance is

(0.2631 + j1.656)*20 / 317.4 = (0.01658 + j0.0734) per unit

Figure 3.1, "Sample Outputs from Program TMLC to Determine Zero-Sequence Mutual Impedance between Two Transmission Lines" contains the output of the Transmission Line Constants program (TMLC) for the above example; it assumes 15 miles of common circuit length.

```
                     POWER TECHNOLOGIES, INC.
                 TRANSMISSION LINE CHARACTERISTICS
                 PROGRAM VER III            11-28-89

                     PARALLEL 230KV AND 138KV

 VALUES IN OHMS/MI AND MOHM-MI
 *SEQ.FOR CIRCUIT #1
  R0         X0         XC0
 0.31923    2.30837    0.30290
  R1         X1         XC1
 0.04973    0.59483    0.14135

 *SEQ. COUP. CIRCUITS #1-2
  R0         X0
 0.26310    1.16563

 *SEQ.FOR CIRCUIT #2
  R0         X0         XC0
 0.35660    2.65663    0.43585
  R1         X1         XC1
 0.09940    0.72455    0.17005
```

ohm value per mile




```
ENTER OUTPUT OPTION.
       0-NO MORE OUTPUT, EXIT PROGRAM
       1-FULL IMPEDANCE MATRIX
       2-FULL SYMMETICAL COMP. MATRIX
       3-ABBREVIATED SYMM. COMP.
       4-SUMMARIZED RESULTS DATA FILE
       5-POWER FLOW
       6-SHORT CIRCUIT
       7-LIST OUT DATA
       8-WRITE INPUT DATA FILE
       9-CHANGE DATA
      10-CHANGE OUTPUT DEVICE
      11-ANOTHER CASE WITH NEW DATA: 6

DEFAULT IS 100 MVA, DO YOU WANT TO CHANGE IT? 100
FOR EACH CIRCUIT ENTER KV
      FOR CIRCUIT 1
         ENTER KV: 230
      FOR CIRCUIT 2
         ENTER KV: 138
FOR EACH CIRCUIT ENTER SELF CIRCUIT LENGTH
AND LENGTH IN COMMON WITH OTHER CIRCUITS
IN MILES (DEFAULT COMMON LENGTH IS 0.0)
  CIRCUIT 1
      ENTER SELF LENGTH: 100
  CIRCUIT 1  TO CIRCUIT 2
      ENTER COMMON LENGTH: 15
  CIRCUIT 2
      ENTER SELF LENGTH: 20

            PARALLEL 230KV AND 138KV
            BASE MVA IS    100.00

                ***********HYPERBOLIC CORRECTION APPLIED*************
                ****************IN PU - TOTAL LENGTH****************
SELF TO             ****POSITIVE SEQUENCE****    ******ZERO SEQUENCE******
CKT  CKT  KV   LNTH(MI)   R        X        B         R        X        B

1         230. 100.000  0.00927  0.11166  0.37556   0.05882  0.43095  0.17577

      2   138.  15.000                               0.0124   0.0551

 2        138.  20.000  0.01043  0.07607  0.02240   0.03742  0.27889  0.00874
```

per unit value for 15 mi.

Figure 3.1. Sample Outputs from Program TMLC to Determine Zero-Sequence Mutual Impedance between Two Transmission Lines

3.2. Choice of MVA Base

While the almost universal choice of voltage base for the calculation and stating of per-unit data is rated or nominal line-to-line voltage, there is no corresponding conventional choice of MVA base. Transmission line data is usually stated with respect to an arbitrarily chosen base such as 100 MVA, but per-unit impedances of transformers, generators, and other equipment may be stated with respect to a variety of MVA base values. The most common MVA base choices for generators and transformers are

- Equipment continuous rating.
- An arbitrary figure, not necessarily the same as for transmission line data.

It is prudent, therefore, to accompany all per-unit data with a statement of the base value of MVA used in its calculation.

Similarly, all computer programs requiring input data in per-unit form must state the necessary MVA base for each item of data. If the program requires data to be expressed with respect to an MVA base that is different from the one used in the original data, the engineer must convert to the new base. The most widely used conversion formula follows from Equation 3.20

$$\frac{Z_{LG\ base1}}{Z_{LG\ base2}} = \frac{MVA_{base2}}{MVA_{base1}} \tag{3.7}$$

The more complete conversion formula is

$$\frac{Z_{LG\ base1}}{Z_{LG\ base2}} = \frac{MVA_{base2}}{MVA_{base1}} \left(\frac{V_{LL\ base1}}{V_{LL\ base2}}\right)^2 \tag{3.8}$$

3.3. Expressions for Power Flow

The complex power flowing past any point in a three-phase power system is given by

$$S = v_a i_a^* + v_b i_b^* + v_c i_c^* \tag{3.9}$$

where v_a, v_b, and v_c are the rms line-to-ground voltages, and i_a, i_b, and i_c are the rms line currents. This complex power summation may be expressed in the vector for

$$S = i_1^* v_1 \tag{3.10}$$

where v_l is the line-to-ground rms voltage vector containing v_a, v_b, and v_c; and i_l is the line rms current vector containing i_a, i_b, and i_c.

For balanced operation, where the three pairs of line-to-ground voltage and current have equal amplitude and power factor angles, Equation 3.9 becomes

$$S = 3V_1 I_1^* \tag{3.11}$$

where V_1 and I_1 are the rms values of line-to-ground voltage and line current, respectively. Furthermore, in balanced operation, the line-to-ground voltage amplitude is $(1 / \sqrt{3})$ times the line-to-line voltage amplitude, V_{LL}, and hence

$$S = \sqrt{3} V_{LL} I_1^* \tag{3.12}$$

Because the majority of power system simulation calculations are made in terms of symmetrical components, these power expressions must be recast in terms of symmetrical component currents and voltages. Recall from Section 2.3.1, "The Symmetrical Component Transformation" that the symmetrical component voltage and current vectors are related to the line-to-ground voltage and line current vectors by

$$v_1 = T v_s \tag{3.13}$$

$$i_1 = T\, i_s \tag{3.14}$$

Substituting these into Equation 3.10 gives

$$S = i_s^*\, T^*\, T\, v_s \tag{3.15}$$

But, from the definition of the symmetrical component transformation in Section 2.3.1, "The Symmetrical Component Transformation",

$$T^{-1} = \frac{1}{3} T^* \tag{3.16}$$

Therefore,

$$T^* = 3T^{-1} \tag{3.17}$$

which may be substituted into Equation 3.15 to give the symmetrical component expression for complex power

$$S = 3i_s^* v_s \tag{3.18}$$

3.4. Normalized Data Values

The preceding section explained the characterization of the power transmission line in terms of physical units: volts, amperes, and ohms. While it would be possible to carry out the full-scale simulation of a power system in terms of these physical units, it is not done in practice for a variety of historical and technical reasons.

The range of numerical values in a computation is always a practical concern, and the range of parameter values in the simulation of a large network is very large. For example, transmission line operating voltages may range from 69 to 750 kV in a single network model. This single-decade range may give rise to a double-decade range in line impedances and power flows. Such a hundred fold range in values was difficult to handle accurately in the analog computing equipment used in the early development of network analysis. Modern digital computers can handle such ranges without difficulty, but it is, nevertheless, simpler and more economical to execute digital computations with a minimal range of numerical values.

Most power system analysis uses a system of parameter normalization in which all voltages, currents, and power flows are expressed per unit of the designated base values (e.g., ohm/mile, ohm/kilometer). This system is convenient in connection with transmission lines and transformers, and virtually necessary for the dynamic simulation of generators and their controls.

3.5. Per-Unit Impedance and Admittance

The transmission line was characterized in Chapter 2, *Transmission Lines* in terms of line-to-ground voltages and line currents. Furthermore, the symmetrical component voltages and currents were defined as transformations of the line-to-ground voltages and line currents. All line series impedances and shunt admittances were derived in Chapter 2, *Transmission Lines* as constants relating line-to-ground voltage and line-to-ground current. Accordingly, the base for expression of impedances in per-unit terms is defined as

$$Z_{LG\ base} = \frac{V_{LG\ base}}{I_{L\ base}} \tag{3.19}$$

Even though this base impedance relates line-to-ground voltage to line current, it is convenient to express base impedance in terms of the nominal, line-to-line, system voltage and the base MVA. Recognizing that $V_{LG\ base} = (V_{LL\ base} / \sqrt{3})$, and using Equation 3.21 gives

$$\begin{aligned} Z_{LG\ base} &= \frac{V_{LL\ base}}{\sqrt{3}} \times \frac{\sqrt{3}V_{LL\ base}}{MVA_{base}} \\ Z_{LG\ base} &= \frac{V^2_{LL\ base}}{MVA_{base}} = \frac{3V^2_{LG\ base}}{MVA_{base}} \end{aligned} \tag{3.20}$$

Table 3.1, "Base Current and Impedance when Base MVA = 100" summarizes base impedances and base currents for the common transmission voltages when the base MVA is taken as 100 MVA. The admittance base value is the reciprocal of the base impedance.

Table 3.1. Base Current and Impedance when Base MVA = 100

System Voltage $V_{LL\ base}$, kV	Line-to-Ground Base Voltage $V_{LG\ base}$, kV	Base Line Current $I_{L\ base}$, A	Base Line-to-Ground Impedance, $Z_{LG\ base}$, Ω
69	39.8	837	47.6
138	79.7	418	190
230	132.8	251	529
345	199.2	167	1190
400	230.9	144	1600
500	288.7	115	2500
765	441.7	75	5852
1100	635.1	52	12100

As an example of the calculation of per-unit values of transmission line parameters, consider the 200-mile 345-kV circuit discussed in Section 2.5.3, "Equivalent Circuit of Finite Transmission Line". Figure 2.9, "Use of TMLC to Calculate Equivalent-Circuit Data for a Line of Finite Length", the output of program TMLC, shows the exact positive sequence parameters of this line to be

$Z_{ex} = 6.34 + j108.48$ ohms

Y_{ex} = j1539 micromhos

The base impedance at 345 kV, with a 100 MVA base, is 1190 ohms. The per-unit values of the line parameters are, therefore,

$$Z_{ex} = \frac{6.34 + j108.48}{1190} = 0.0053 + j0.0912$$

$Y_{ex} = 1539 \times 10^{-6} \times 1190 = 1.83$

3.6. Per-Unit Statement of System Variables

3.6.1. Voltage

The per-unit value of a voltage is defined as

$$\frac{\text{Actual Voltage in kV}}{\text{Base Voltage in kV}}$$

The base voltages applicable to a three-phase power system analysis are the nominal values of the voltages being expressed. The base value of line-to-line voltage is the nominal system voltage, the base value for line-to-ground voltage is the nominal value of line-to-ground voltage, and so on. The base values for key power system voltage measurements are summarized in Table 3.2, “Base Voltage Values for Three-Phase Power System”. The nominal values of voltage used as the reference basis for expressing voltages per-unit will be referred to as $V_{LL\ base}$ or $V_{LG\ base}$, for line-to-line and line-to-ground values, respectively.

Table 3.2. Base Voltage Values for Three-Phase Power System

System Nominal Voltage, kV	Base LL Voltage	Base LG Voltage	Base Positive-, Negative-, or Zero-Sequence Voltage
V_{LL}	V_{LL}	$V_{LL} / \sqrt{3}$	$V_{LL} / \sqrt{3}$
69	69	39.84	39.84
138	138	79.67	79.67
230	230	132.8	132.8
345	345	199.2	199.2
400	400	230.9	230.9
500	500	288.7	288.7
765	765	441.7	441.7

It is the responsibility of the user to specify the appropriate numerical value of base voltage when converting per-unit voltages into physical units. For example, suppose a symmetrical component fault analysis calculation has resulted in a voltage specification of $v_0 = 0.5$ per unit, $v_1 = 0.4$ per unit, and $v_2 = 0.5$ per unit for a bus of a 500-kV system. The a-phase-to-ground voltage is

$v_a = v_0 + v_1 + v_2 = 0.5 + 0.4 + 0.5 = 1.4$ per unit

The base voltage for phase-to-ground measurements in a 500-kV system is ($500 / \sqrt{3}$) = 288.7 kV. The a-phase-to-ground voltage is, therefore, 1.4 x 288.7 = 404.2 kV.

3.6.2. Volt-Amperes and Current

The per-unit values of volt-ampere, real power, and reactive power flows are defined as

$$\frac{\text{Actual Flow in MW, Mvar, or MVA}}{\text{Base MVA}}$$

Unlike base voltage, which is set equal to nominal voltage for each system component, base MVA is selected arbitrarily without regard for component MVA ratings. In transmission network analysis, three-phase MVA, 100 MVA for example, is applied to all components of the network and will be written as MVA_{base}.

From Section 3.3, “Expressions for Power Flow”, per-unit power flow in a three-phase system is given by the vector expressions

$$\frac{3i_1^* v_1}{MVA_{base}}$$

or

$$\frac{3i_s^* v_s}{MVA_{base}}$$

in general unbalanced conditions, or by

$$\frac{\sqrt{3} V_{LL} I_L^*}{MVA_{base}}$$

in balanced conditions.

The base value of line current follows from the specification of base MVA. The base value of line current, $I_{L\ base}$, is defined by

$$\begin{aligned} MVA_{base} &= \sqrt{3} V_{LL\ base} I_{L\ base} \\ &= 3V_{LG\ base} I_{L\ base} \end{aligned} \tag{3.21}$$

Base line current, $I_{L\ base}$, is then the line current that must flow for the system to carry base MVA at nominal (or base) voltage. Note that base current is not synonymous with rated current; it is equal to rated current only if the base MVA value is chosen to be equal to rated MVA of the line, transformer, or machine under consideration. Per-unit line current is defined as

$$\frac{\text{Actual Line Current in Amps}}{\text{Base Line Current in Amps}}$$

3.7. Power System Equations in Per-Unit Form

3.7.1. Ohms Law

The equations describing power system components may be written in terms of per-unit variables. The translation of an equation relating voltages and currents in terms of physical units into a relationship between per-unit variables is best shown by example. Consider the simple situation shown in Figure 3.2, "Simple System Configuration Example, Radial Feeder to Motor Load". The equation for positive-sequence voltage at the load bus is

$$v_{m1} = v_{b1} - z_{f1}\, i_{f1} \qquad (3.22)$$

where voltages, current and impedance are expressed in volts, amperes, and ohms, respectively. All terms of Equation 3.22 can be divided by the same constant, $V_{LG\ base}$, to give

$$\frac{v_{m1}}{V_{LG\ base}} = \frac{v_{b1}}{V_{LG\ base}} - \frac{z_{f1}\, i_{f1}}{V_{LG\ base}} \qquad (3.23)$$

Now multiply both numerator and denominator of the second rms term by the constant, $I_{L\ base}$, and rearrange to give

$$\frac{v_{m1}}{V_{LG\ base}} = \frac{v_{b1}}{V_{LG\ base}} - \frac{z_{f1}\, I_{L\ base}}{V_{LG\ base}} \times \frac{i_{f1}}{I_{L\ base}} \qquad (3.24)$$

Now each term of this scaled equation corresponds directly to a definition of a per-unit voltage, current, or impedance, as given in Section 3.6, "Per-Unit Statement of System Variables". Therefore, using these definitions, Equation 3.24 may be restated as

$$v_{m1} = v_{b1} - z_{f1} i_{f1} \qquad (3.25)$$

where

v_{m1}, v_{b1}

Per-unit motor and bus positive-sequence voltage.

i_{f1}

Per-unit positive-sequence motor current.

z_{f1}

Feeder positive-sequence impedance.

Similar scalings may be made for the negative and zero sequence equations.

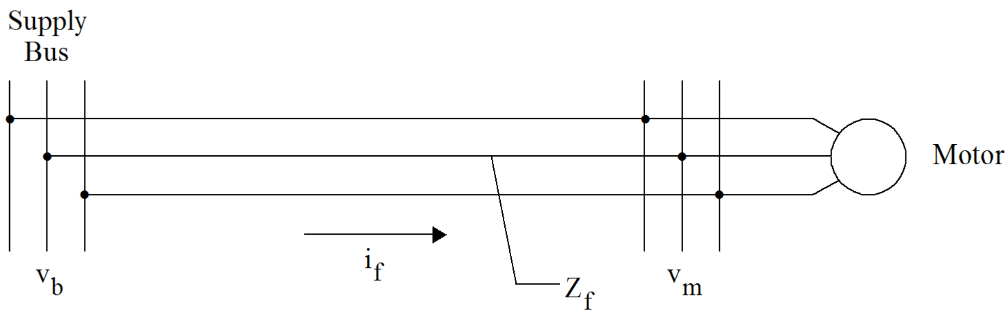


Figure 3.2. Simple System Configuration Example, Radial Feeder to Motor Load

It is apparent that Equation 3.25, relating per-unit variables, has the same form as the original Equation 3.22 from which it was obtained. It should be noted that both z_{f1} and i_{f1} are expressed per unit with respect to the same MVA base. The choice of base values, then, affects the numerical values of the per-unit current and impedance, but does not affect the form of the equation relating per-unit variables.

3.7.2. Power Flow Equations

The complex power flowing into the feeder is given by

$$P + jQ = 3(i_{f1}^{*}v_{b1} + i_{f2}^{*}v_{b2} + i_{f0}^{*}v_{b0}) \tag{3.26}$$

Divide each term of this by the arbitrary constant ($3V_{\text{LG base}}\, I_{\text{L base}}$) to obtain

$$\frac{P + jQ}{3V_{\text{LG base}}\, I_{\text{L base}}} = \frac{3(i_{f1}^{*}v_{b1} + i_{f2}^{*}v_{b2} + i_{f0}^{*}v_{b0})}{3V_{\text{LG base}}\, I_{\text{L base}}} \tag{3.27}$$

Now, from the definition of Equation 3.21, with recognition that

$$V_{\text{LG base}} = V_{\text{LL base}} / \sqrt{3} \tag{3.28}$$

the denominator of the left hand side is identical to MVA $_{\text{base}}$. Therefore Equation 3.27 may be restated as

$$\frac{P + jQ}{MVA_{\text{base}}} = \frac{i_{f1}^{*}v_{b1} + i_{f2}^{*}v_{b2} + i_{f0}^{*}v_{b0}}{I_{\text{L base}}\, V_{\text{LG base}}} \tag{3.29}$$

and, in accordance with the definitions of Section 3.6, "Per-Unit Statement of System Variables", this is identical to

$$\overline{P} + j\overline{Q} = \overline{i}_{f1}^{*}\overline{v}_{b1} + \overline{i}_{f2}^{*}\overline{v}_{b2} + \overline{i}_{f0}^{*}\overline{v}_{b0} \tag{3.30}$$

Equation Equation 3.30 is the per-unit form of the power flow equation. It is apparent that the same current and MVA base must be used for both complex power and sequence current. It should be noted that the per-unit power flow equation is not identical to the original equation relating power, voltage, and current in physical units; the multiplying factor of 3 is not present in the per-unit form equation.

Chapter 4

Transformers in the Positive-Sequence

4.1. Equivalent Circuit for Per-Unit System

4.1.1. Derivation and Basis

The derivation of a per-unit transformer equivalent circuit requires the use of a base value for the number of turns on each winding. Assume, for convenience, that both primary and secondary windings are connected between line and ground as in a wye-wye three-phase bank. Then the base number of turns, n_{b1} and n_{b2}, must satisfy the base voltage relationship

$$\frac{n_{b1}}{n_{b2}} = \frac{V_{LG\ base1}}{V_{LG\ base2}} \tag{4.1}$$

Because of tapping, the actual number of turns on each winding, n_1 and n_2, is not necessarily equal to the base number of turns. The per-unit number-of-turns values, t_1 and t_2, are defined for each winding by

$$t_1 = \frac{n_1}{n_{b1}} \tag{4.2}$$

$$t_2 = \frac{n_2}{n_{b2}} \tag{4.3}$$

The principal per-unit transformer equation can then be obtained by dividing Equation 4.29 by the primary winding base voltage, $V_{LG\ base1}$, and subsequent manipulations using Equation 4.1, Equation 4.2, and Equation 4.3 as follows:

$$\frac{e_1}{V_{LG\ base1}} = \frac{n_1}{n_2}\frac{e_2}{V_{LG\ base1}} + \frac{x_1 i_1}{V_{LG\ base1}} + \frac{n_1}{n_2}\frac{x_2 i_2}{V_{LG\ base1}}$$

$$\bar{e}_1 = \frac{n_1}{n_2}\frac{e_2}{V_{LG\ base2}} \times \frac{V_{LG\ base2}}{V_{LG\ base1}} + \frac{x_1 i_1 MVA_{base1}}{(3V_{LG\ base1})^2 I_{L\ base1}} + \frac{n_1}{n_2}\frac{x_2 i_2}{V_{LG\ base2}}\frac{V_{LG\ base2}}{V_{LG\ base1}}$$

$$\bar{e}_1 = \frac{n_1}{n_2}\bar{e}_2\frac{n_{b2}}{n_{b1}} + \frac{x_1 i_1}{Z_{base1} I_{L\ base1}} + \frac{n_1}{n_2}\frac{x_2 i_2}{Z_{base2} I_{L\ base2}}\frac{n_{b2}}{n_{b1}} \tag{4.4}$$

$$\bar{e}_1 = \frac{t_1}{t_2}\bar{e}_2 + \bar{x}_1\bar{i}_1 + \frac{t_1}{t_2}\bar{x}_2\bar{i}_2$$

Equation Equation 4.4 corresponds to the equivalent circuit shown in Figure 4.1, “Per-Unit Transformer Equivalent Circuit with Off-Nominal Tap Position on Both Sides”. This apparently simple equivalent circuit is not suitable for general power system analysis use because the per-unit impedances, x_1 and x_2, are not constant. Comparison of Equation 4.28 and Equation 4.29 shows that

$$x_1 = \frac{w\,k_1\,n_1^2}{Z_{base1}}$$

$$x_2 = \frac{w\,k_2\,n_2^2}{Z_{base2}} \tag{4.5}$$

Because changing tap positions changes n_1 and n_2, and may also change k_1 and k_2, x_1 and x_2 are variables that would have to be adjusted with each change in tap position. A more practical transformer per-unit equivalent may be obtained by defining two nominal-tap unit impedances, x_1' and x_2', and assuming that k_1 and k_2 do not change with change in tap position.

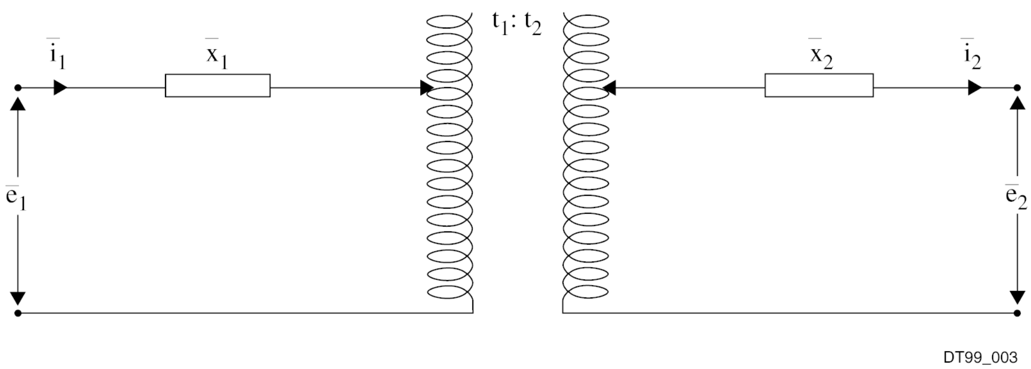


Figure 4.1. Per-Unit Transformer Equivalent Circuit with Off-Nominal Tap Position on Both Sides

Thus,

$$\bar{x}_1 = \bar{x}_1' |t_1|^2 \tag{4.6}$$

$$\bar{x}_2 = \bar{x}_2' |t_2|^2 \tag{4.7}$$

because the inductance of a winding is fundamentally proportional to the square of its number of turns.

Substituting Equation 4.6, Equation 4.7 into Equation 4.4 gives the more useful expression

$$\bar{e}_1 = \frac{t_1}{t_2}\bar{e}_2 + (|t_1|^2\bar{x}_1')\,\bar{i}_1 + \frac{t_1}{t_2}(|t_2|^2\bar{x}_2')\,\bar{i}_2 \tag{4.8}$$

The equivalent circuit corresponding to this equation is shown in Figure 4.2, "Per-Unit Transformer Equivalent Using Nominal-Tap Per-Unit Impedances". It is more practical than that of Figure 4.1, "Per-Unit Transformer Equivalent Circuit with Off-Nominal Tap Position on Both Sides" as it involves only two variable parameters, t_1 and t_2, rather than the four variable parameters t_1, t_2, x_1, and x_2. It is still unsuited to large-scale power system analysis, however, because its two constant, $x_1{}'$ and $x_2{}'$, and two variable, t_1 and t_2, parameters represent a level of detail in representation that is not normally available from power system databases.

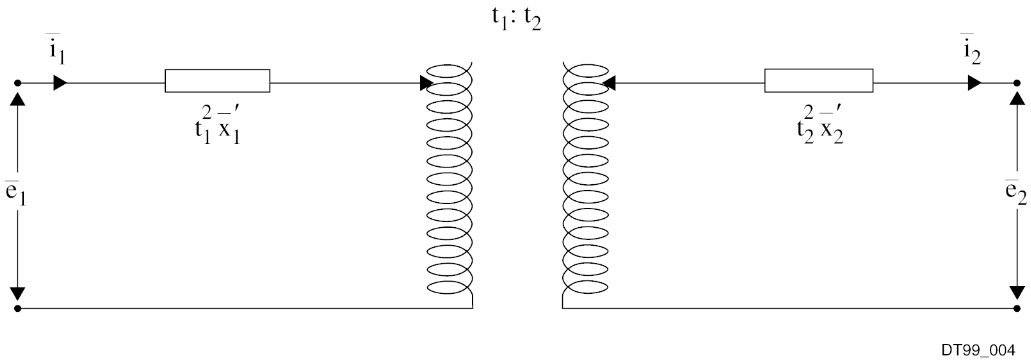


Figure 4.2. Per-Unit Transformer Equivalent Using Nominal-Tap Per-Unit Impedances

The most widely used form of per-unit transformer equivalent is obtained by defining the per-unit turns ratio, *t*, as

$$
\begin{aligned}
t &= \frac{t_1}{t_2} = \frac{n_1}{n_2} \times \frac{n_{b2}}{n_{b1}} \\
&= \frac{n_1}{n_2} \times \frac{V_{LG\ base2}}{V_{LG\ base1}}
\end{aligned}
\tag{4.9}
$$

Use of this definition gives the per-unit forms of Equation 4.21 and Equation 4.22 as

$$\frac{\bar{e}_1}{\bar{e}_2} = t \tag{4.10}$$

$$\frac{\bar{i}_1}{\bar{i}_2} = \frac{1}{t^*} \tag{4.11}$$

Now, multiplying Equation 4.8 through by t_2/t_1 and substituting Equation 4.11 gives

$$
\begin{aligned}
\bar{e}_2 &= \frac{\bar{e}_1}{t} - \frac{t_2}{t_1}\left(|t_1|^2\,\bar{x}_1'\right)\bar{i}_1 - \left(|t_2|^2\,\bar{x}_2'\right)\bar{i}_2 \\
\bar{e}_2 &= \frac{\bar{e}_1}{t} - \left[\left(\frac{t_2}{t_1}\right)\left(\frac{t_2}{t_1}\right)^*\left(|t_1|^2\,\bar{x}_1'\right) + \left(|t_2|^2\,\bar{x}_2'\right)\right]\bar{i}_2 \\
\bar{e}_2 &= \frac{\bar{e}_1}{t} - \left[\left(\bar{x}_1' + \bar{x}_2'\right)|t_2|^2\right]\bar{i}_2
\end{aligned}
\tag{4.12}
$$

Finally, it is convenient to change the subscripts 1 and 2 to *i* and *j* and rewrite Equation 4.12 in the more widely used form

$$\bar{e}_j = \frac{\bar{e}_i}{t} - [(\bar{x}_i' + \bar{x}_j') \mid t_j \mid^2] \bar{i}_j \tag{4.13}$$

or

$$\bar{e}_j = \frac{\bar{e}_i}{t} - \bar{x}_{eq} \bar{i}_j \tag{4.14}$$

where

$$\bar{x}_{eq} = \mid t_j \mid^2 (\bar{x}_i' + \bar{x}_j') \tag{4.15}$$

Equation Equation 4.14 corresponds to the equivalent circuit shown in Figure 4.3, "Standard Per-Unit Form Transformer Equivalent Circuit". This is the standard positive sequence transformer model as recognized by the great majority of utility databases and by the IEEE Common Format for Exchange of Solved Power Flow Cases.

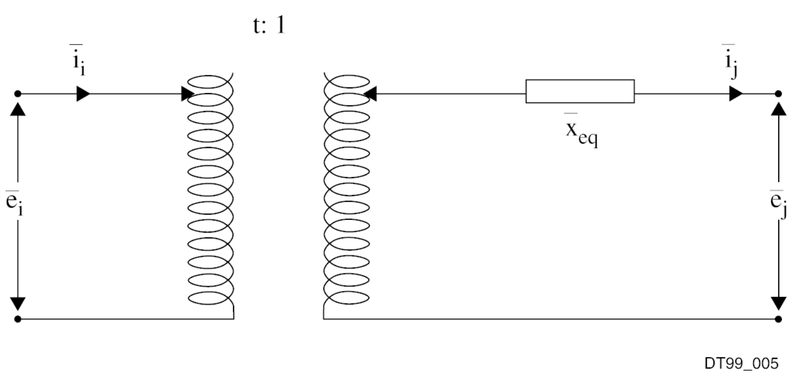


Figure 4.3. Standard Per-Unit Form Transformer Equivalent Circuit

In PSS®E, for a two-winding transformer, the calculation of t and x_{eq} is handled automatically when the user specifies t_j and alternate voltage bases. For x_{eq}, the user enters the measured impedance across the windings at nominal tap position. PSS®E internally makes the following calculations:

$$\bar{x}_{eq} = |t_j|^2 (\bar{x}_1' + \bar{x}_j') \left(\frac{V_{\text{base j nameplate}}}{V_{\text{base j desired}}} \right)^2 \left(\frac{\text{MVA desired}}{\text{MVA nameplate}} \right) \tag{4.16}$$

$$t = \frac{t_i}{t_j}\left(\left(\frac{V_{\text{base i nameplate}}}{V_{\text{base i desired}}}\right) / \left(\frac{V_{\text{base j nameplate}}}{V_{\text{base j desired}}}\right)\right) \quad (4.17)$$

4.1.2. Transformer Equivalent Circuit Summary

A recapitulation of the characteristics of this transformer model is in order:

1. Figure 4.3, "Standard Per-Unit Form Transformer Equivalent Circuit" is based on the assumption that the winding leakage reactances are proportional to the number of turns squared as tap position is adjusted. That is, it is assumed that changing tap position does not alter the flux field map of the transformer. While this assumption is not satisfied exactly in practical transformer designs, it is reasonable in that deviations from the square-law proportionality are small in most transformers.

2. PSS®E automatically adjusts Z_{eq} if t_j is changed.

4.1.3. Two-Winding PSS®E Data Model Entry

Internally, PSS®E represents a two-winding transformer with the equivalent circuit model shown in Figure 4.4, "PSS®E Two-Winding Transformer Model". This model allows representation of the magnetizing admittance, Ym = Gh+e -j Bm, that is often neglected on the i-side (winding 1) of the transformer. Data entry for this model unburdens the user from having to calculate the equivalent leakage impedance, magnetizing branch admittance, effective taps, tap step, and tap limits. Data flexibility also allows the user to specify the equivalent leakage impedance in per unit on either system MVA base and winding voltage base (or nominal tap) or transformer winding MVA base and winding voltage base (or nominal tap), or by specifying the windings full-load loss in Watts and the leakage impedance magnitude (or impedance voltage) in per unit on a winding MVA base and winding voltage base. The user can also choose to enter tap position by specifying voltages in kV or in per unit on bus voltage base or on winding voltage base. Figure 4.5, "Standard PSS®E Two-Winding Transformer Circuit" and Figure 4.6, "Standard PSS®E Two-Winding Transformer Circuit" show the standard PSS®E two-winding transformer equivalent circuit.

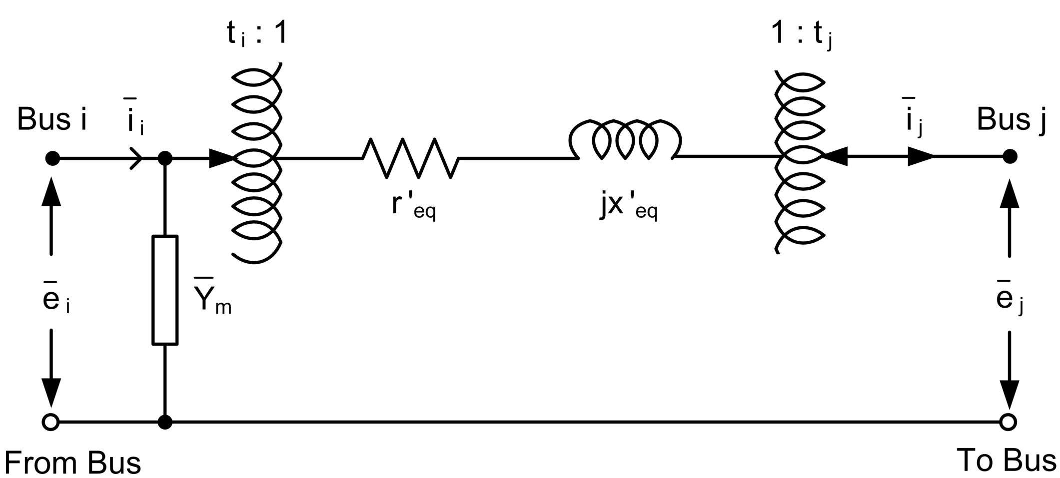
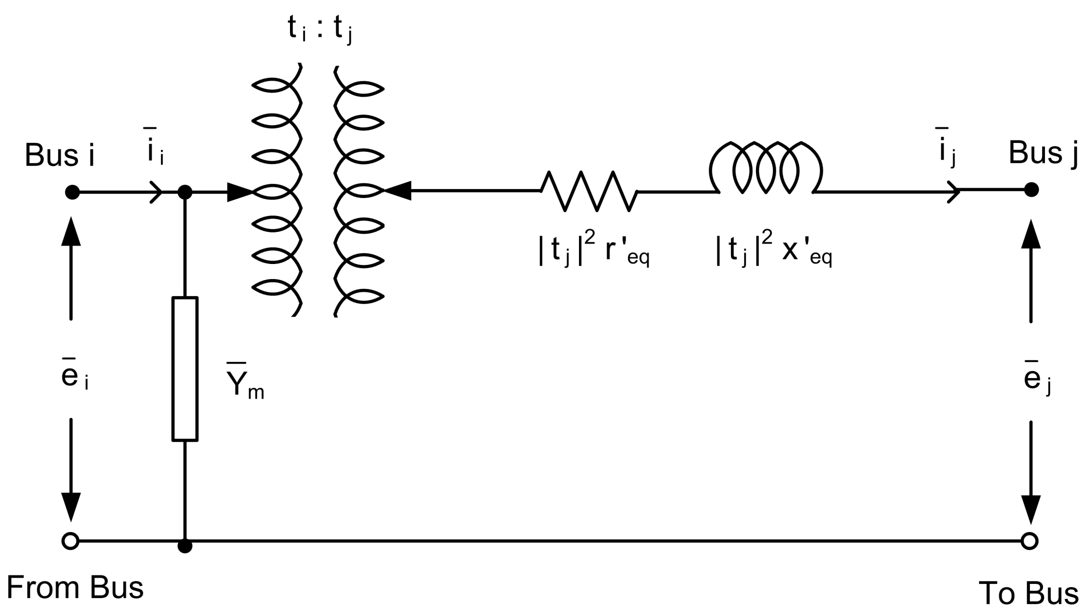


Figure 4.4. PSS®E Two-Winding Transformer Model



$$\bar{Z}_{eq} = |t_j|^2 r'_{eq} + j|t_j|^2 x'_{eq} = \bar{r}_{eq} + j\bar{x}_{eq}$$

Figure 4.5. Standard PSS®E Two-Winding Transformer Circuit

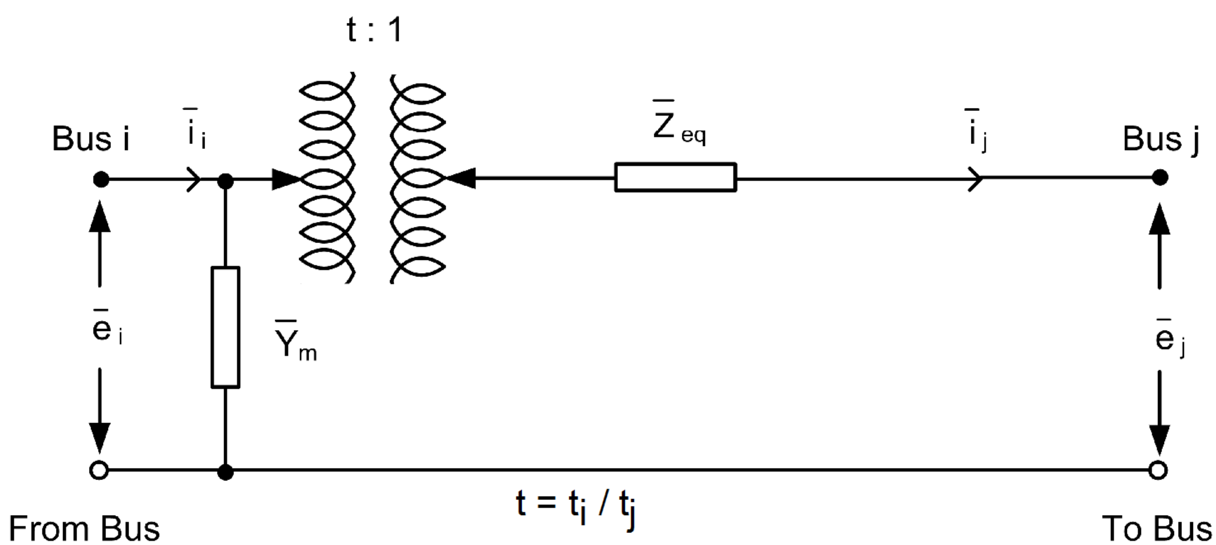


Figure 4.6. Standard PSS®E Two-Winding Transformer Circuit

4.2. Equivalent Circuit in Physical Units

Next, the solution of Equation 4.23through Equation 4.27 for the case $i_2 = 0$ yields

$$e_1 = \omega (k_m n_1^2 i_1 + k_1 n_1^2 i_1) \qquad (4.18)$$

The term

$$k_m n_1^2$$

, is the primary side magnetizing inductance. The equation may be rewritten as

$$e_1 = (x_{m1} + x_1) i_1 \qquad (4.19)$$

where x_{m1} is the primary winding magnetizing reactance.

Similarly, for the secondary winding

$$e_2 = - \left[\left(\frac{n_1}{n_2} \right)^2 x \; x_{m1} + x_2 \right] i_2 \qquad (4.20)$$

Equations Equation 4.29, Equation 4.19 and Equation 4.20 reveal that the transformer constructed as shown in Figure 4.9, “Flux Linkages of Transformer Windings via Common Path and Leakage Paths”can be represented by the equivalent circuit of Figure 4.7, “Transformer Equivalent Circuit for Use with Physical (V, A, Ω) Quantization of Currents and Voltages”. This figure shows the leakage and magnetizing impedances attached to the input and output of an ideal transformer, which is characterized by the relationships

$$\frac{e_1}{e_2} = \frac{n_1}{n_2} \qquad (4.21)$$

$$\frac{i_1^*}{i_2^*} = \frac{n_1}{n_2} \qquad (4.22)$$

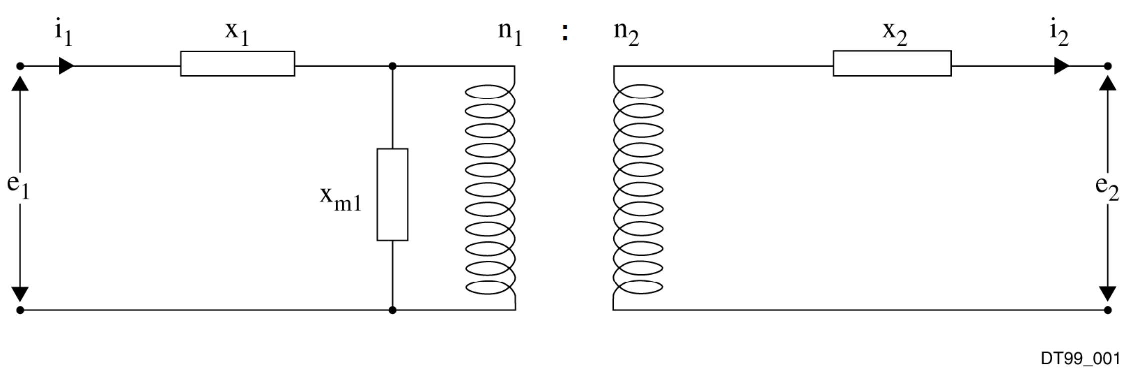


Figure 4.7. Transformer Equivalent Circuit for Use with Physical (V, A, #) Quantization of Currents and Voltages

The magnetizing reactance, x_{m1}, is normally very large in relation to the leakage reactances, x_1 and x_2. The primary magnetizing current, as given by Equation 4.19, is typically as little as one-half percent of rated primary current in a large power transformer. The primary current obtained when the secondary is short circuited, as obtained from Equation 4.29 with e_2 set to zero, would typically be ten times rated current. Hence, x_{m1} is typically 2000 times larger (in ohms) than x_1. The x_{m1} branch is, therefore, commonly regarded as an open circuit and neglected in power system analyses; the basic transformer characterization is taken to be the simplified equivalent circuit of Figure 4.8, “Standard Transformer Circuit for Use with Physical Units (V, A, Ω); Magnetizing Branch Ignored”.

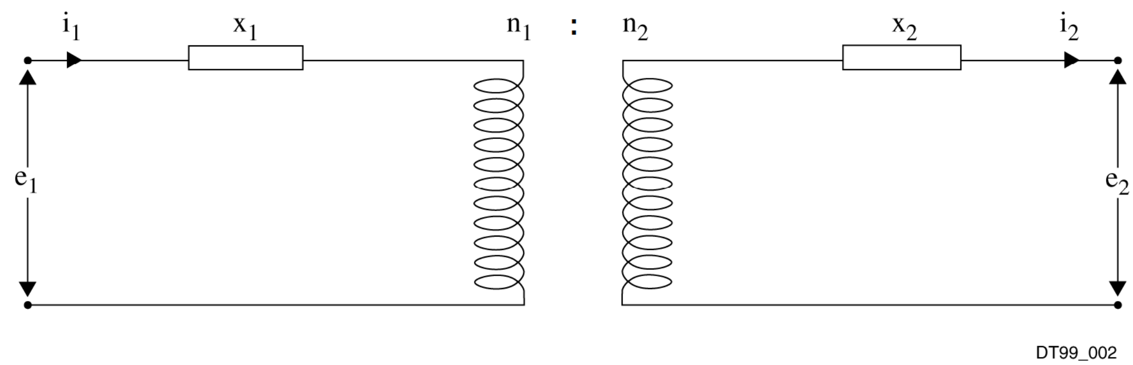


Figure 4.8. Standard Transformer Circuit for Use with Physical Units (V, A, #); Magnetizing Branch Ignored

4.3. Leakage Reactance

Consider a two-winding power transformer arranged as shown in Figure 4.9, "Flux Linkages of Transformer Windings via Common Path and Leakage Paths", where the application of primary and secondary voltages, e_1 and e_2, results in terminal currents, i_1 and i_2. A field map of the flux established by these currents will reveal three components of flux, ϕ_1, ϕ_2, and ϕ_m. The flux, ϕ_m, links both windings and is the means by which energy is transferred between windings. The fluxes, ϕ_1 and ϕ_2, do not contribute to energy transfer because they link only one winding each. They are called leakage fluxes and usual transformer design practice calls for their minimization.

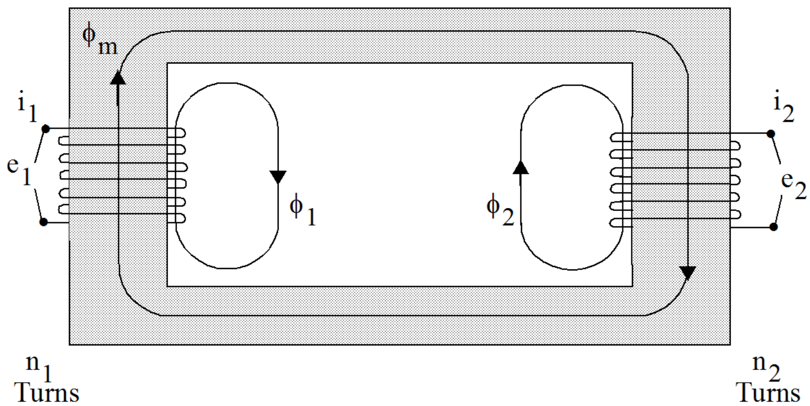


Figure 4.9. Flux Linkages of Transformer Windings via Common Path and Leakage Paths

The two windings produce magneto-motive forces (mmf), $n_1 i_1$ and $n_2 i_2$. The fluxes may be related to these mmfs by the permeances of the flux paths. Hence

$$\phi_1 = k_1 n_1 i_1 \tag{4.23}$$

$$\phi_2 = - k_2 n_2 i_2 \tag{4.24}$$

$$\phi_m = k_m (n_1 i_1 - n_2 i_2) \tag{4.25}$$

where k_1, k_2, and k_m are the permeances of the three flux paths.

In sinusoidal operating conditions, the application of Maxwell's law gives the voltage relations

$$e_1 = \omega n_1 (\phi_1 + \phi_m) \tag{4.26}$$

$$e_2 = \omega n_2 (\phi_2 + \phi_m) \tag{4.27}$$

The mmf and voltage equations can be solved to yield

$$e_1 = \frac{n_1}{n_2} e_2 + \omega k_1 n_1^2 i_1 + \frac{n_1}{n_2} \omega k_2 n_2^2 i_2 \tag{4.28}$$

The terms

$$k_1 n_1^2$$

and

$$k_2 n_2^2$$

have the dimensions of inductance and are called the leakage inductances of the two windings. The multiplication of these inductances by operating frequency, ω , gives the leakage reactances, x_1, and x_2, of the two windings. Hence, Equation 4.28 may be rewritten in the form

$$e_1 = \frac{n_1}{n_2} e_2 + x_1 i_1 + \frac{n_1}{n_2} x_2 i_2 \tag{4.29}$$

where voltages, currents, and impedances are expressed in the physical units of volts, amperes, and ohms.

4.4. Perspective

Chapter 2, *Transmission Lines* and Chapter 3, *The Per-Unit Data System* established the characteristics of transmission lines, introduced the symmetrical component coordinate system, and defined the per-unit system. The symmetrical component characteristics for the remaining types of power system equipments, specifically generators, loads, and transformers, must also be established. This section deals with the positive-sequence characteristics of transformers. Transformer zero-sequence characteristics can be quite complicated and, accordingly, are dealt with in a separate section.

4.5. Phase-shifting Transformers

Phase-shifting transformers are used in power system grid to control the flow of active power by adjusting the voltage phase angle between two buses in a meshed network. This change in phase angle is carried out by adding a regulated voltage to the source end phase to neutral bus voltage. A winding connected in series with the transmission system is used to insert in the network the regulated voltage that when added with the appropriate phase to the source voltage sets up the direction of the active power flow between the transformer terminals.

Two designs are the most prevalent in power systems: symmetric phase-shifting transformers and asymmetric phase shifting-transformers. The former type carries the phase shifting operation with a constant voltage amplitude at the source and load windings while the latter type carries the phase shifting operation with a variable voltage amplitude.

The symmetrical phase-shifting transformer add the regulating voltage in quadrature with the voltage at the midpoint of the series winding of the phase-shifting transformer. The IEEE model for a phase-shifting transformer is based on the symmetrical phase-shifting transformer, and thus the voltage amplitude of the winding voltages do not change during the phase shifting operation of the transformer. The complex transformer ratio for this type of phase-shifting transformer is then

$$1.0 \times e^{\pm j\varphi}$$

The no-load phase shift angle φ is the angle by which the winding 1 voltage leads the winding 2 voltage.

The asymmetric phase-shifting transformer add the regulating voltage with a winding connection angle α to the source phase-to-neutral voltage.

When the winding connection angle α is ±90º the phase-shifting transformer is called a quadrature phase-shifting transformer or a "quadrature booster" transformer. This phase-shifting transformer type changes not only the phase angle between the winding 1 and winding 2 voltages but also the magnitude of the winding voltages. Thus, the complex transformer ratio for this type of phase-shifting transformer is then $t^*e^{\pm j0}$, where "t" is the transformer turns ratio, t_1/t_2, and t_1 and t_2 the winding 1 and winding 2 turns ratios.

Figure 4.10, “Symmetric Phase-shifting Transformer” and Figure 4.11, “Asymmetric Phase-shifting Transformer” show the schematic representation of a symmetric and asymmetric phase-shifting transformers. The general no-load voltage ratio between the phase-to-neutral voltages at the terminals of the series windings is:

$$\frac{\overline{V}}{\overline{V}'} = t \times e^{j\varphi} \quad \text{(per unit)}$$

Neglecting winding losses and using the principle of energy conservation, the power into the phase-shifting transformer must be equal to the power flowing out of the transformer:

$$\overline{V}\overline{I^*} = \overline{V}'\overline{I'^*} \quad \text{(per unit)}$$

or

$$\frac{\overline{V}}{\overline{V}'} = \frac{\overline{(I')}^*}{\overline{(I)}^*} = te^{j\varphi} \quad \text{(per unit)}$$

The asterisk in the equation above represents the complex conjugate operation. Note that the same phase shift angle applies to winding voltages and winding currents.

The general model for asymmetric phase-shifting transformers is shown in Figure 4.12, "Phase-shifting Transformer General Model". This model is specified in terms of the following parameters:

- Phase shift angle range [$\varphi_{max}, \varphi_{min}$] in degrees.
- Number of tap positions.
- nominal tap position: $1.0^* e^{\pm j0^\circ}$ (per unit on bus voltage base).
- transformer leakage impedance at nominal tap position in per unit on winding voltage base and on either system apparent power base or winding 1-2 apparent power base.
- winding connection angle α in degrees.

Note that when the winding connection angle α is 0º this general model represents a conventional voltage magnitude regulating transformer (OLTC/ULTC) and when the winding connection angle α is 90º the model represents a "quadrature booster" phase-shifting transformer. Applying the Law of Sines to the triangle describing this model one can infer that for a "quadrature booster" phase-shifting transformer with a symmetric phase-shifting angle range, the change in voltage, ΔV, in the series winding for a phase shift angle φ is given by the expression:

$$\Delta V = \tan(\varphi); \quad \varphi_{min} \le \varphi \le \varphi_{max} \qquad \text{(per unit)}$$

and the off-nominal transformer turns ratio t is given by

$$t = \frac{1.0}{\cos(\varphi)}; \quad \varphi_{min} \le \varphi \le \varphi_{max} \quad \text{(per unit)}$$

For a given winding connection angle α, the change in voltage, ΔV, in the series winding for a phase shift angle φ is given by the general expression:

$$\Delta V = \frac{\sin(\varphi)}{\sin(\alpha - \varphi)}; \varphi_{min} \le \varphi \le \varphi_{max} \quad \text{(per unit)}$$

and the off-nominal transformer turns ratio t for a winding connection angle $\alpha \ne 0°$ is

$$t = \frac{\sin(\alpha)}{\sin(\alpha - \varphi)}; \quad \varphi_{min} \le \varphi \le \varphi_{max} \quad \text{(per unit)}$$

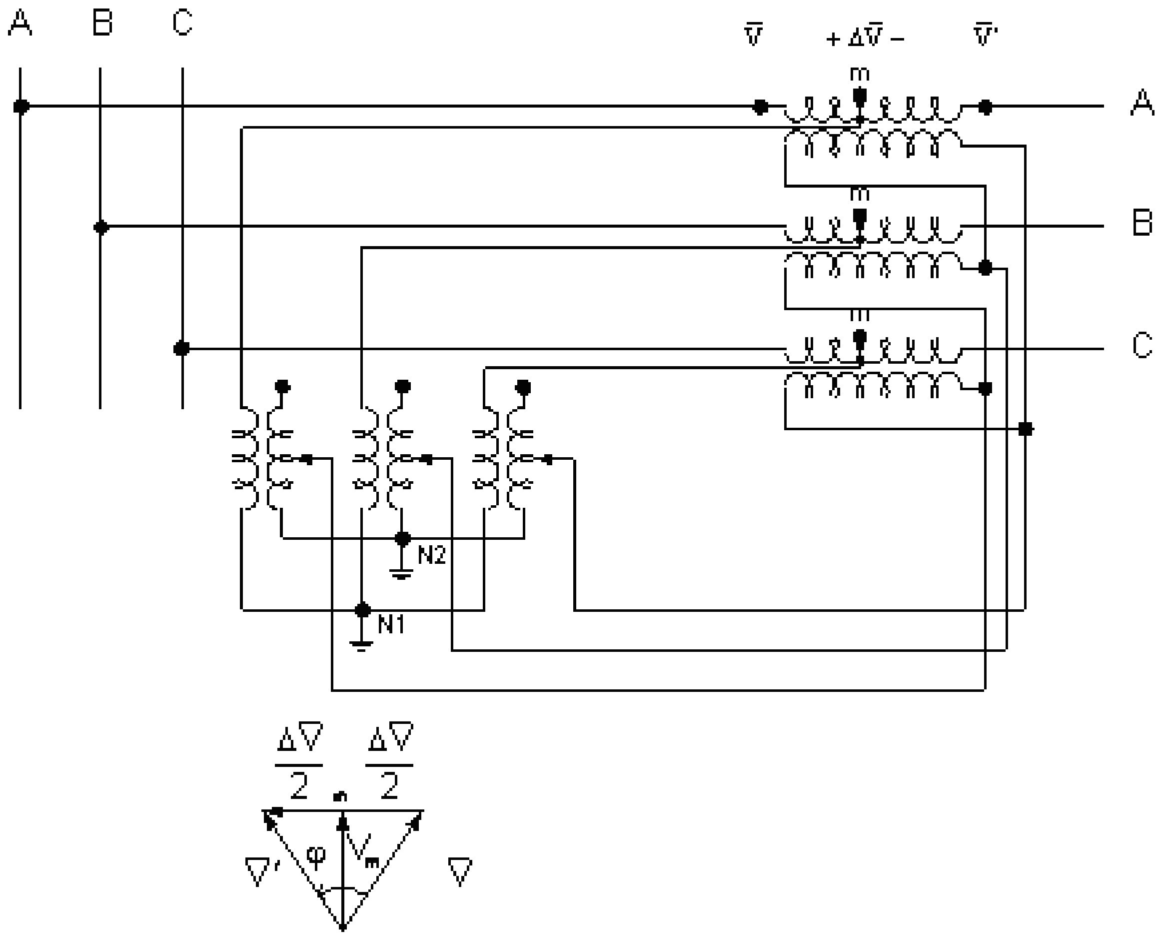


Figure 4.10. Symmetric Phase-shifting Transformer

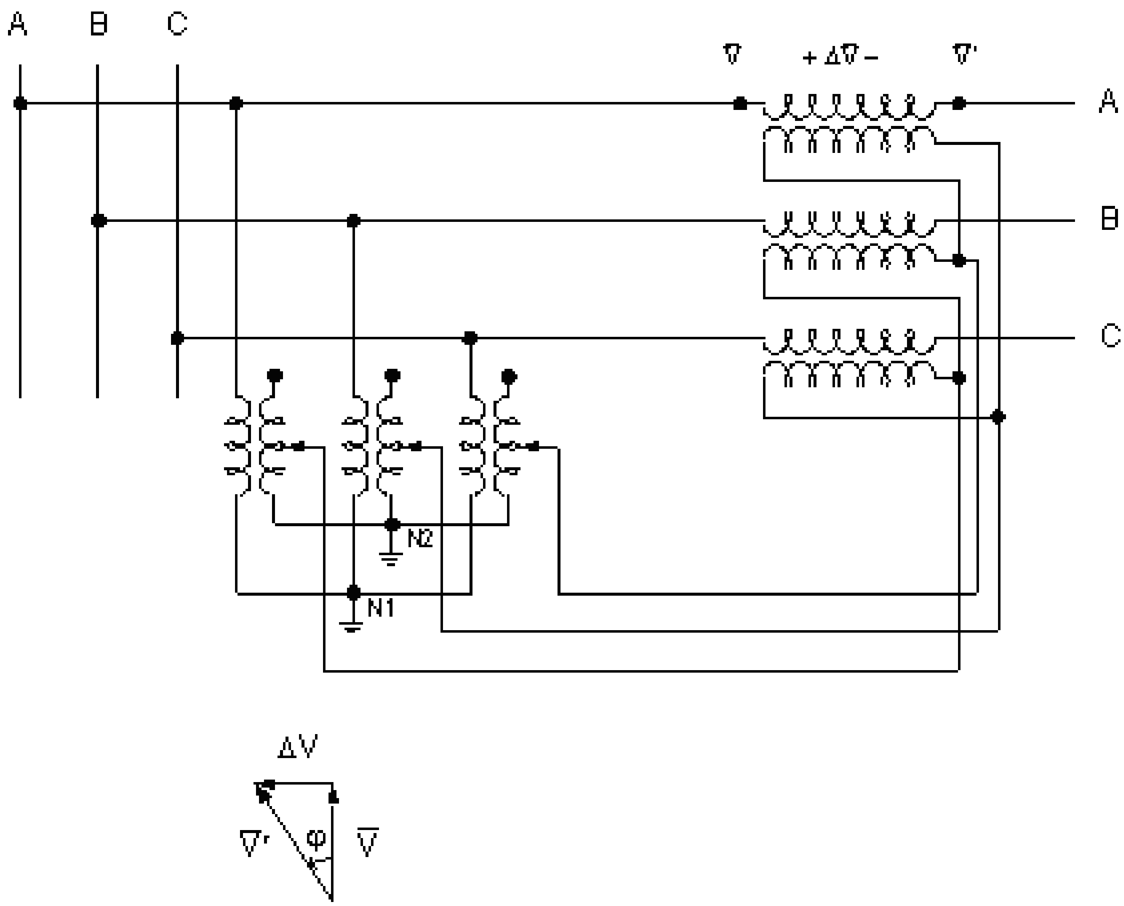


Figure 4.11. Asymmetric Phase-shifting Transformer

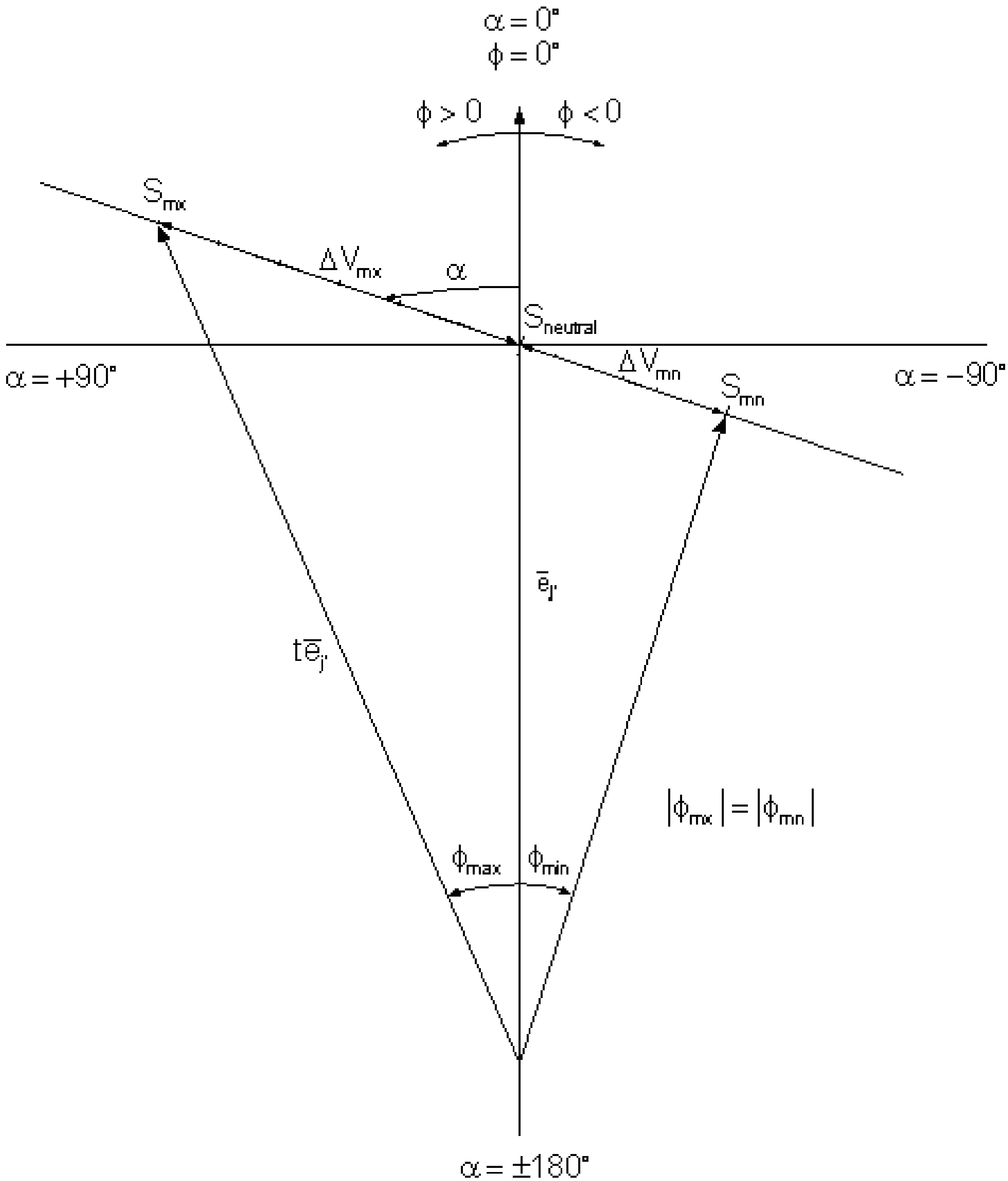
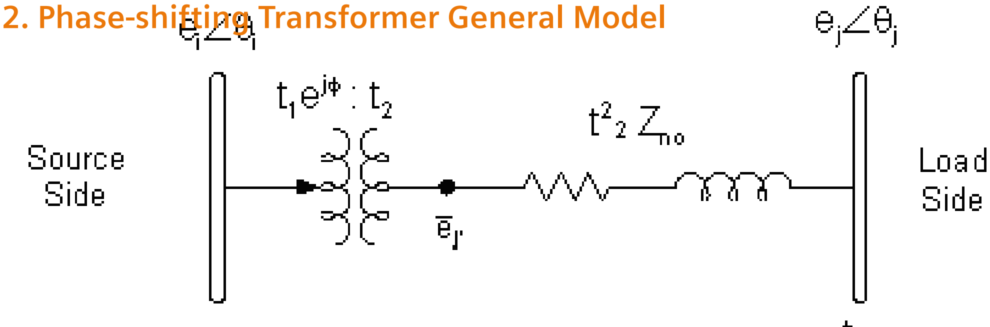


Figure 4.12. Phase-shifting Transformer General Model



4.5.1. Representation in PSS®E

The phase-shifting transformer model used in PSS®E is shown in Figure 4.13, "Standard PSS®E Phase-shifting Transformer Circuit Model". The user has several choices , like in voltage regulating transformers, to enter the data specifying the transformer's leakage impedance and magnetizing branch admittance. These parameters can be entered in per unit or from data collected in the short circuit and no-load tests. Only winding 1 is allowed to have an under-load tap changer. Winding 2 can have an off-load tap changer. Tap position, maximum and minimum phase-shift angles are specified in electrical degrees. Control band is specified in MW.

While transformers are represented in the network model by the equivalent circuit of Figure 4.13, "Standard PSS®E Phase-shifting Transformer Circuit Model", transformer data is often stated in terms of test parameters : winding copper losses at rated current, iron losses and short circuit or impedance voltage, rather than in terms of the per unit impedance of the branch connecting the transformer terminals as shown in Figure 4.13, "Standard PSS®E Phase-shifting Transformer Circuit Model".

The test parameters are measured at nominal tap position and are, accordingly, related to the nominal tap impedance as designated in Figure 4.5, "Standard PSS®E Two-Winding Transformer Circuit". The user inputs the test values between windings, and PSS®E automatically calculates the equivalent branch impedance shown in Figure 4.13, "Standard PSS®E Phase-shifting Transformer Circuit Model".

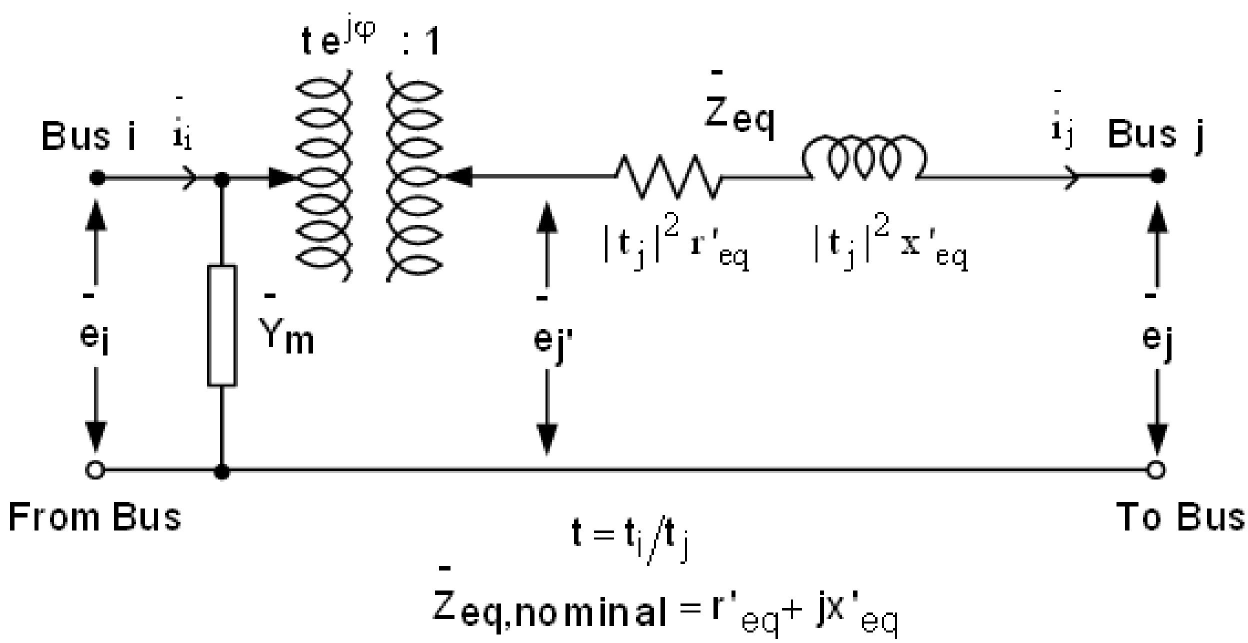


Figure 4.13. Standard PSS®E Phase-shifting Transformer Circuit Model

The user may specify a non- metered end used in loss calculations.

For power flow calculations the user must set the transformer's control mode to either active power control using a symmetric phase shifting transformer or active power control using an asymmetric phase shifting transformer, the phase-shift angle range in electrical degrees, the winding connection angle in electrical degrees, the transformer loading limits and the active power control band both in MW. A negative control mode (COD1 = -3 or -5) indicates that the phase shift angle is held fixed in the load flow solution.

The default value for the winding connection angle is 0°. The use of this default winding connection angle with the MW asymmetrical phase shifter transformer control mode is considered in PSS®E as modeling a symmetrical phase shifting transformer. Asymmetrical phase shifting transformers can be modeled by specifying a winding connection angle in the range 0° to 360°.

The phase-shift angle adjustment is continuous and all adjustable phase-shifting transformers are adjusted simultaneously whenever the regulated active power flow of at least one of them falls outside its scheduled control band. An unduly narrow control band may cause non-convergence of the power flow solution. A reasonable control band is ±5 MW of the active power target flow.

Since the phase-shifting transformers are static power components, the positive sequence leakage impedance should be equal to the negative sequence leakage impedance but the phase shift angle is reversed. That is, if the positive sequence phase-shift angle the sign of is $+\varphi$ the negative sequence phase shift angle is then $-\varphi$. This change in sign causes the shunt and series elements of the pi-equivalent network to be different from those used in the positive sequence network. If the classical short circuit solution is selected in the PSS®E short circuit module, both positive and negative sequence representation of a phase-shifting transformer will be identical since the phase shift angle φ is set to 0°.

The zero sequence network representation for phase-shifting transformers is dependent on the winding connections of the series and shunt transformers, their core construction and whether the shunt transformer has any delta-connected tertiary winding. The connection code 9 could be used to represent the phase-shifting transformer in the zero sequence network where winding 1 is the shunt transformer and winding 2 is the series transformer.

The impedance of the T-equivalent network connected to the winding 1 terminals corresponds to the regulating transformer sequence impedance as seem from its input terminals, the impedance connected to the winding 2 terminals corresponds to the series transformer's zero sequence as seen from its output terminals, and the shunt branch in this equivalent network represents either the impedance of a tertiary winding or the stray air path of the zero sequence flux through the tank walls.

As an example of data preparation for a symmetrical phase-shifting transformer, consider a 500/230 kV, three-phase, two-winding transformer with OA rating of 800 MVA and nominal winding phase to phase voltages of 500 kV and 230kV. The positive sequence leakage impedance at nominal tap is 0.0 +j 0.08 per unit on a 800 MVA, 500/230 kV base. The total number of tap positions is 39 and the phase shift angle range is ±30°. The minimum, maximum and neutral tap position is 1, 39 and 20, respectively.

The PSS®E data record is shown below. Note that the winding angle connection is set to zero, its default value, and the control mode is set to 3 for active power (MW) symmetrical PAR.

```
     PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS®E      THU, MAY 12 2011  10:52
PSS(R)E PROGRAM APPLICATION GUIDE EXAMPLE                      2 WINDING XFRMER
BASE CASE INCLUDING SEQUENCE DATA                                CONTROL DATA
X------ FROM BUS -------X X------- TO BUS --------X     W C                                                   X---- CONTROLLED BUS ----X CONECXN
  BUS# X-- NAME --X BASKV   BUS# X-- NAME --X BASKV CKT 1 W CN   RMAX     RMIN     VMAX    VMIN  NTPS    BUS# X-- NAME --X BASKV   ANGLE
   202 EAST500      500.00   203 EAST230      230.00  1  F 1  3  30.000 -30.000  555.00  545.00   33                                 0.000
```

Figure 4.14. PSS®E Data Record for the Symmetrical Phase-shifting Transformer

If the phase-shifting transformer data used in the previous numerical example belongs to an asymmetrical "quadrature booster" phase-shifting transformer, then the only changes in the data record required from the user is the change in winding connection angle to 90°, and the change in the control mode to 5 for active power (MW) asymmetrical PAR. Figure 4.15, "PSS®E Data Record for the Asymmetrical Phase-shifting Transformer" shows the data record for the "quadrature booster" phase-shifting transformer.

.

```
     PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS®E      THU, MAY 12 2011  11:01
PSS(R)E PROGRAM APPLICATION GUIDE EXAMPLE                     2 WINDING XFRMER
BASE CASE INCLUDING SEQUENCE DATA                               CONTROL DATA
X------ FROM BUS -------X X------- TO BUS --------X     W C                                                   X---- CONTROLLED BUS ----X CONECXN
  BUS# X-- NAME --X BASKV   BUS# X-- NAME --X BASKV CKT 1 W CN   RMAX    RMIN     VMAX    VMIN  NTPS    BUS# X-- NAME --X BASKV   ANGLE
   202 EAST500      500.00   203 EAST230      230.00  1  F 1  5  30.000 -30.000  555.00  545.00   33                                 90.000
```

```
    PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS®E      THU, MAY 12 2011  11:01
SS(R)E PROGRAM APPLICATION GUIDE EXAMPLE                      2 WINDING XFRMER
ASE CASE INCLUDING SEQUENCE DATA                               WINDING DATA
------ FROM BUS -------X X------- TO BUS --------X     C
 BUS# X-- NAME --X BASKV   BUS# X-- NAME --X BASKV CKT W  WINDV1  NOMV1  ANGLE  WINDV2  NOMV2   RATEA  RATEB  RATEC OWNR FRACT OWNR FRACT
  202 EAST500      500.00   203 EAST230      230.00  1  1 1.01543 0.0000   10.0 1.00000 0.0000  800.0 1040.0 1200.0    2 1.000
```

Figure 4.15. PSS®E Data Record for the Asymmetrical Phase-shifting Transformer

Note that for a winding connection angle of 90°, a control mode 5 and a phase shift angle of 10°, the required value for t1 is 1.0154 per unit on 500 kV a system bus voltage base.

4.6. Tap-Changing Transformers

The transformer equivalent of Figure 4.3, "Standard Per-Unit Form Transformer Equivalent Circuit" has as parameters:

- Per-unit turns ratio, t.
- Equivalent impedance, x_{eq}.

The equivalent impedance is dependent on the number of turns on the *j*-side winding, but independent of the number of turns on the *i*-side winding.

A tap-changing transformer may, therefore, be represented accurately by Figure 4.3, "Standard Per-Unit Form Transformer Equivalent Circuit" with a constant value of x_{eq} as long as tap-changing affects the number of turns on one winding only. Figure 4.3, "Standard Per-Unit Form Transformer Equivalent Circuit" does not require nominal number of turns, or tap position, on one side of the transformer. It can give accurate representation of a transformer with a fixed, or off-load, tap in one winding and an adjustable, or on-load, tap-changer in the other. This is achieved by:

- Assigning the *i*-side (from bus) of Figure 4.3, "Standard Per-Unit Form Transformer Equivalent Circuit" to the variable-tap winding, winding 1.
- Assigning the *j*-side (to bus) of Figure 4.3, "Standard Per-Unit Form Transformer Equivalent Circuit" to the fixed-tap winding, winding 2.

As an example of the data preparation procedure, consider a wye-wye transformer having the following data available on its name plate:

Winding 1 Nominal Voltage:	230 kV
Winding 2 Nominal Voltage:	69 kV
Rating:	50 MVA
Reactance:	8%
Manual Tap on 69-kV Winding:	+0, +2, +4%
Automatic Taps on 230-kV Winding:	±6.25% in steps of 0.625%

Assume the user wishes to enter data in per unit on system base. With both winding 1 and winding 2 untapped, and if this transformer is to be modeled with a 230-kV primary base and a 69-kV secondary base, the correct per-unit data for use with Figure 4.3, "Standard Per-Unit Form Transformer Equivalent Circuit" are:

- *i*-side (230-kV side) with *i*-side base kV set to 230.
- *j*-side (69-kV side) with *j*-side base kV set to 69.

In this example, the user does not wish to enter a to bus tap. PSS®E would internally make the following calculations:

From Equation 4.16, x_{eq} (the per-unit value for a 100 MVA base)

$$= (x_i' + x_j') \times \frac{100}{50} = 0.08 \times \frac{100}{50} = 0.16$$

From Equation 4.17, nominal-tap ratio, *t*

$$= \frac{t_i}{t_j} = 1.0$$

Maximum per-unit tap ratio, t_{max}

$$= \frac{t_{i\,max}}{t_2} = \frac{1.0625}{1.0} = 1.0625$$

Minimum per-unit tap ratio, t_{min}

$$= \frac{t_{i\,min}}{t_2} = \frac{0.9375}{1.0} = 0.9375$$

Effective tap ratio step

$$= \frac{0.00625}{1.00} = 0.00625 \text{ per unit}$$

The PSS®E data record is shown below:

```
100, 101, 0,'1 ',1,2,1, 0.00000, 0.00000,2,'2WXFMR ',1, 1,1.0000

0.00000, 0.08000, 50.00

1.00000, 230.000, 0.000, 0.00, 0.00, 0.00, 1, 101, 1.06250, 0.93750, 1.05000,
0.95000, 21, 0, 0.00000, 0.00000

1.00000, 69.000
```

PSS®E Data Record, Example 1

For a second example of data preparation, suppose, for the above transformer, that the winding 2 tap was known to be in the +2% position at the last maintenance inspection. With all other conditions unchanged, the correct per-unit data to use are

- *i*-side (230-kV side) with *i*-side base kV set to 230.
- *j*-side (69-kV side) with *j*-side base kV set to 69.

The user can specify all the bus base kV and transformer nominal voltages and avoid applying the following calculations; having PSS®E apply these calculations is recommended.

x_{eq} in per-unit value on 100 MVA base

$$= |\, t_j \,|^2 \,(x_i' + x_j') \times \frac{100}{50} = 1.02^2 \times 0.08 \times \frac{100}{50} = 0.1665$$

Off-nominal tap ratio, *t* =

$$= \frac{t_i}{t_j} = \frac{1.0}{1.02} = 0.9804$$

Maximum per-unit turns ratio, t_{max} =

$$\frac{t_{i\,max}}{t_j} = \frac{1.0625}{1.02} = 1.0147$$

Minimum per-unit tap ratio, t_{min} =

$$\frac{t_{i\,min}}{t_j} = \frac{0.9375}{1.02} = 0.9191$$

Effective tap ratio step

$$= \frac{0.00625}{1.02} = 0.00613 \text{ per unit}$$

The PSS®E data record is shown below:

```
100, 101, 0,'1 ',1,2,1, 0.00000, 0.00000,2,'2WXFMR ',1, 1,1.0000

0.00000, 0.08000, 50.00

1.00000, 230.000, 0.000, 0.00, 0.00, 0.00, 1, 101, 1.06250, 0.93750, 1.05000,
0.95000, 21, 0, 0.00000, 0.00000

1.02000, 69.000
```

PSS®E Data Record, Example 2

As a third example, if the transformer in example 2 is modeled so that the winding 1 base kV is 224 and the winding 2 base kV remains at 69, then the correct per-unit data to use are

- *i*-side (230-kV side) with *i*-side base kV set to 224.
- *j*-side (69-kV side) with *j*-side base kV set to 69.

x_{eq} in per-unit on 100 MVA is the same as before,

$$x_{eq} = |t_j|^2 (x_i' + x_j') \times \frac{100}{50} = 0.1665$$

From Equation 4.17, the off-nominal tap ratio, *t*

$$= \frac{1.0}{1.02} \times \frac{230}{224} = 1.00665$$

Maximum per-unit turns ratio, t_{max}

$$= \frac{1.0625}{1.02} \times \frac{230}{224} = 1.0695$$

Minimum per-unit turns ratio, t_{min}

$$= \frac{0.9375}{1.02} \times \frac{230}{224} = 0.9437$$

Effective tap ratio step

$$= \frac{0.00625}{1.02} \times \frac{230}{224} = 0.00629 \text{ per unit}$$

The PSS®E data record is shown below:

```
100, 101, 0,'1 ',1,2,1, 0.00000, 0.00000,2,'2WXFMR ',1, 1,1.0000

0.00000, 0.08000, 50.00

1.02668, 230.000, 0.000, 0.00, 0.00, 0.00, 1, 101, 1.09090, 0.96260, 1.05000,
0.95000, 21, 0, 0.00000, 0.00000

1.02000, 69.000
```

PSS®E Data Record, Example 3

Now, for a fourth example, suppose the same transformer (i.e., that in the third example) is modeled with base voltages of 224 kV and 67 kV. With all other conditions unchanged, the correct data to use are

- *i*-side (230-kV side) with *i*-side base kV set to 224.
- *j*-side (69-kV side) with *j*-side base kV set to 67.

x_{eq} in the per-unit on 100 MVA base is

$$x_{eq} = |t_j|^2 (x_i' + x_j') \times \left(\frac{69}{67}\right)^2 \left(\frac{100}{50}\right) = 1.02^2 \times 0.08 \times \left(\frac{69}{67}\right)^2 \times \left(\frac{100}{50}\right) = 0.1766$$

Off-nominal taps ratio, *t*

$$= \frac{t_i}{t_j} \times \left(\frac{230}{224}\right) / \left(\frac{69}{67}\right) = \frac{1.0}{1.02} \times \left(\frac{230}{224}\right) / \left(\frac{69}{67}\right) = 0.9775$$

Maximum per-unit tap ratio, t_{max}

$$= \frac{t_{i\,max}}{t_j} \times \left(\frac{230}{224}\right) / \left(\frac{69}{67}\right) = \frac{1.0625}{1.02} \times \left(\frac{230}{224}\right) / \left(\frac{69}{67}\right) = 1.03857$$

Minimum per-unit tap ratio, t_{min}

$$= \frac{t_{i\,min}}{t_j} \times \left(\frac{230}{224}\right) / \left(\frac{69}{67}\right) = \frac{0.9375}{1.02} \times \left(\frac{230}{224}\right) / \left(\frac{69}{67}\right) = 0.9164$$

Effective tap ratio step

$$= \frac{0.00625}{1.02} \times \left(\frac{230}{224}\right) / \left(\frac{69}{67}\right) = 0.006109 \text{ per unit}$$

The PSS®E data record is shown below:

```
100, 101, 0,'1 ',1,2,1, 0.00000, 0.00000,2,'2WXFMR ',1, 1,1.0000

0.00000, 0.08000, 50.00

1.02668, 230.000, 0.000, 0.00, 0.00, 0.00, 1, 101, 1.09090, 0.96260, 1.05000,
0.95000, 21, 0, 0.00000, 0.00000

1.05040, 69.000
```

PSS®E Data Record, Example 4

In all the examples, note that every time t_j changes, all the manual calculations performed must be repeated. Because of this, it is highly recommended that the user specify both taps and let PSS®E apply the calculations. The data used in these examples are more comprehensive than that usually provided in large-scale utility databases. In the more usual situation, the data would be limited to winding 1 and winding 2 nominal voltage in kV, rating in MVA, total nominal-tap reactance, maximum and minimum winding 1 turns ratio, and number of tap steps.

Information on the specific winding tapping arrangements used to achieve the given range of ratios is seldom available in power flow data sets usually being interchanged among utilities and the engineer often has to guess whether winding 1 or winding 2 of the transformer should be used as the *j*-side. In PSS®E, the automatic tap changer must be specified on the i-side.

4.7. Three-Winding Transformers

4.7.1. Representation in PSS®E

The three-winding transformer model that is used internally in PSS®E is shown in Figure 4.16, "Three-Winding Transformer Model". As with the two-winding data input, the user has many choices with respect to data entry. All three windings entered will be allowed to have an automatic tap changer. Tap position and maximum voltage can be specified either in per unit or kV if the bus's base kV has been entered. In this three-winding model, the interior * or T point bus is introduced automatically and will generally appear invisible to the user.

While transformers are represented in the network model by the equivalent circuit of Figure 4.16, "Three-Winding Transformer Model" with a dummy node representing an internal point, transformer data is often stated in terms of test parameters rather than in terms of the reactances of the branches of Figure 4.16, "Three-Winding Transformer Model".

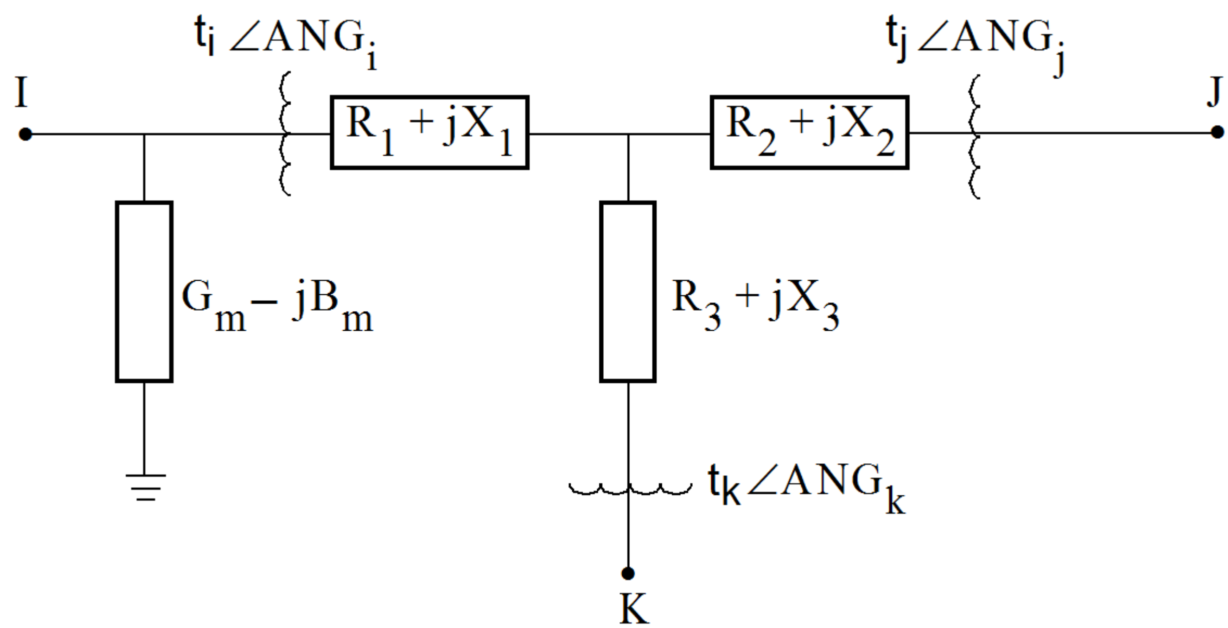
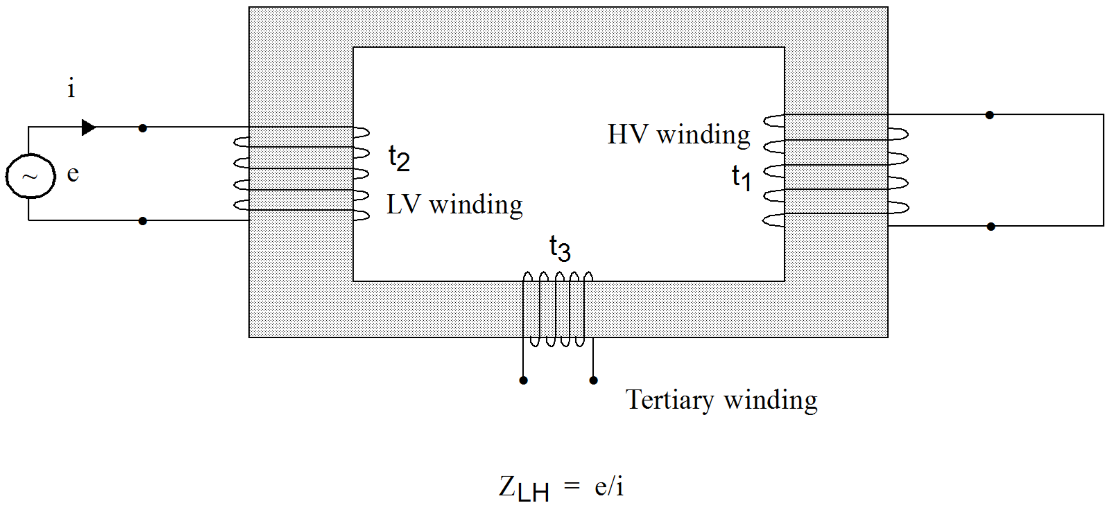


Figure 4.16. Three-Winding Transformer Model

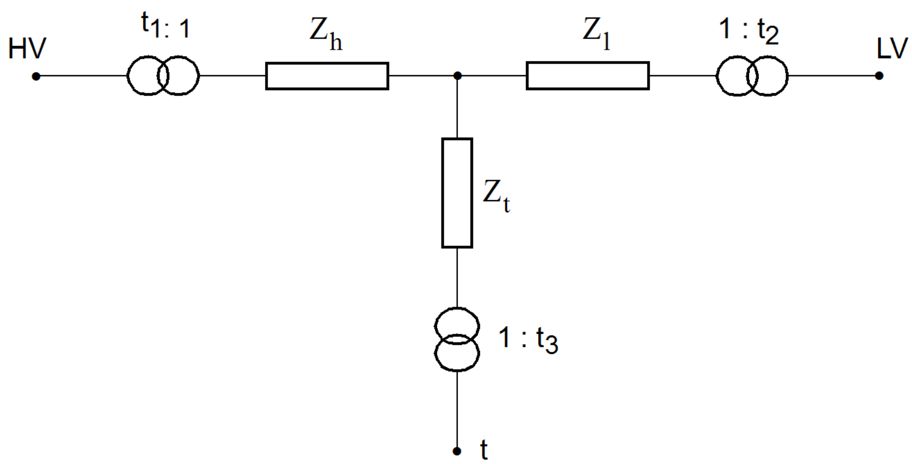
The most common test procedure is illustrated by Figure 4.17, "Relationship Between Three-Winding Transformer Test and Equivalent Circuit Parameters". In this test, one winding is short circuited and one is left open circuited, while a voltage is applied to the remaining winding. This test yields the magnitudes of the three leakage impedances, Z_{LH}, Z_{LT}, and Z_{HT} and winding copper losses W_{LH}, W_{LT}, and W_{HT}. The impedance, Z_{LH}, is the sum of low- and high-voltage winding leakage impedances when the tertiary winding is open, etc.

The test parameters are measured at nominal tap position and are, accordingly, related to the nominal tap impedance as designated in Figure 4.17, "Relationship Between Three-Winding Transformer Test and Equivalent Circuit Parameters"b. The user inputs the test values between windings, and PSS®E automatically calculates the equivalent branch impedances in the T network model shown in Figure 4.16, "Three-Winding Transformer Model". The user has the option of specifying the test values in per unit on system or winding base, or can specify losses and per unit impedance. Any magnetizing losses are assumed at the first bus specified.

This three-winding model allows the user to specify a winding to be placed out-of-service. The user is asked to specify a nonmetered end for interchange and loss calculations.



a. Leakage Reactance Test



b. Equivalent Circuit

Figure 4.17. Relationship Between Three-Winding Transformer Test and Equivalent Circuit Parameters

For power flow calculations, a transformer with an unloaded tertiary winding, as shown in Figure 4.18, "Three-Winding Transformer Representation No Equipment on Tertiary Winding"a, should be represented in PSS®E by two two-winding transformer equivalent branches, dummy bus *m*, and a shunt branch on bus *m*. This representation can be made exact for a transformer in which both primary and secondary windings have adjustable taps by setting the values of t_i and t_j to the per-unit number of turns on the two windings, and using nominal-tap values for all reactances.

While the representation of Figure 4.18, "Three-Winding Transformer Representation No Equipment on Tertiary Winding"b is exact for the case where both primary and secondary are tapped, it is unnecessary in the usual case where only one winding is tapped. In such cases it is more convenient to use the representation shown in Figure 4.18, "Three-Winding Transformer Representation No Equipment on Tertiary Winding"c. Here branch *mj*, from the dummy bus to the secondary bus is specified as a transmission line rather than a transformer. An additional simplification is represented in Figure 4.18, "Three-Winding Transformer Representation No Equipment on Tertiary Winding"d, where the three-winding transformer is modeled by a single two-winding transformer branch; a shunt-to-ground is frequently permissible because the per-unit value of x_j is very small in relation to x_i and x_k.

It is quite common for the value of x_j to be both very small and negative. Because small branch impedances can be detrimental to the convergence of all power flow iterations and negative impedances prevent the convergence of the Gauss Seidel iteration, it is often very desirable to represent three-winding transformers by the simplified connection of Figure 4.18, "Three-Winding Transformer Representation No Equipment on Tertiary Winding"d. A convenient practice is to enter power flow data initially according to Figure 4.18, "Three-Winding Transformer Representation No Equipment on Tertiary Winding"c, and to use functions to eliminate bus *m* and reduce the model to that of Figure 4.18, "Three-Winding Transformer Representation No Equipment on Tertiary Winding"d if and when the low impedance is found to produce convergence or accuracy problems.

A transformer with active equipment such as a synchronous condenser, static var source, or switched reactor/capacitor on its tertiary winding should be represented by the three-winding transformer model of Figure 4.19, "Three-Winding Transformer Representation with Equipment on Tertiary Winding". A transformer with a fixed shunt reactor or capacitor on its tertiary may be represented as shown in Figure 4.18, "Three-Winding Transformer Representation No Equipment on Tertiary Winding", but with the shunt susceptance, B_m, being set to:

$$\frac{1}{B_m} = -x_k - \frac{1}{B_{reactor}}$$

or

$$\frac{1}{B_m} = -x_k + \frac{1}{B_{capacitor}}$$

as appropriate, where $B_{reactor}$ and $B_{capacitor}$ are shunt device ratings in per-unit terms with respect to the system base.

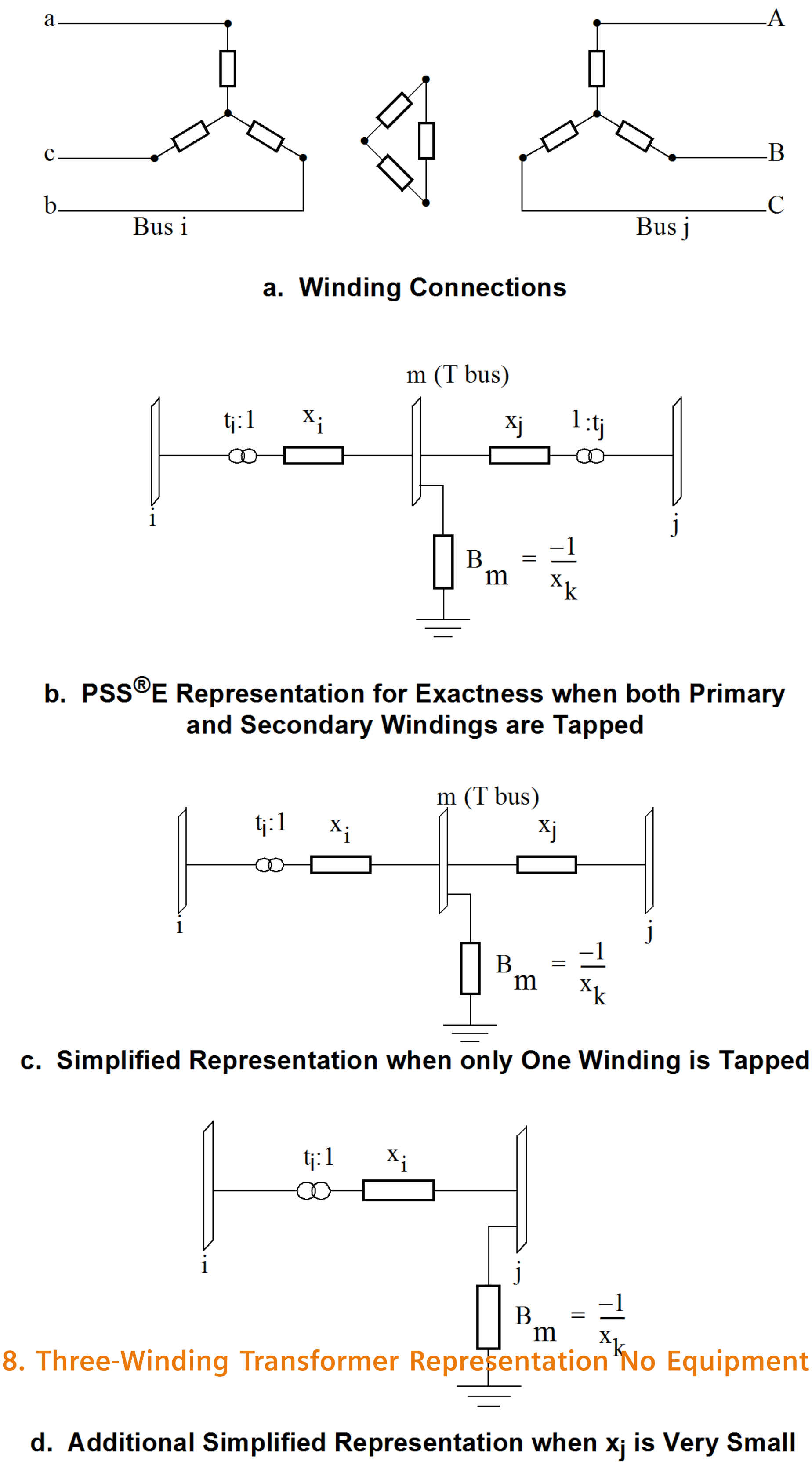
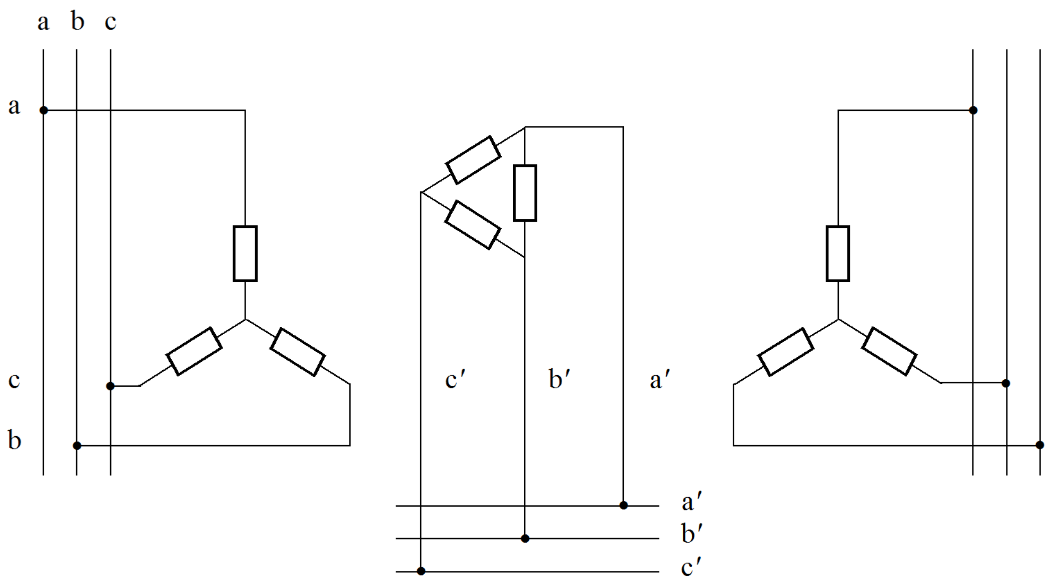
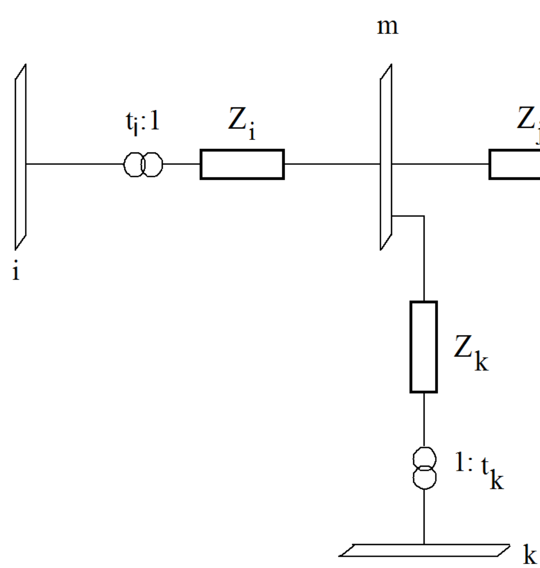


Figure 4.18. Three-Winding Transformer Representation No Equipment on Tertiary Winding



a. Winding Connections



b. PSS®E Representation

Figure 4.19. Three-Winding Transformer Representation with Equipment on Tertiary Winding

As an example of data preparation for a three-winding transformer, consider a three-phase, three-winding transformer connected wye grounded-wye grounded-delta having the following name plate data:

High phase-phase nominal voltage (H): 500 kV GRY

Medium phase-phase nominal voltage (X): 230 kV GRY

Low phase-phase nominal voltage (Y): 13.8 kV

H winding three-phase rating: 130.2/217 MVA

X winding three-phase rating: 130.2/217 MVA

Y winding three-phase rating: 31.14/51.9 MVA

Automatic taps on 500 kV winding: ±5% in steps of 2.5%

Manual taps on 13.8 kV winding: -2.5%, 0%, +2.5%

The short circuit test data for this transformer unit is listed below:

1. Test 1: 500GRY kV to 230GRY kV @ 217 MVA. Three-phase load loss at rated current = 413,800 W; impedance voltage @75°C = 13.24%
2. Test 2: 500GRY kV to 13.8 kV @ 51.9 MVA. Three-phase load loss at rated current = 108,500 W; impedance voltage @75°C = 12.11%
3. Test 3: 230GRY kV to 13.8 kV @ 51.9 MVA. Three-phase load loss at rated current = 104,000 W; impedance voltage @75°C = 8.06%

The open circuit test at 100% voltage yielded the following results:

Three-phase no-load loss @ 100% voltage = 108,300 W. Excitation current @ 100% voltage and 130.2 MVA = 0.22%.

Assume the user wishes to enter the data in PSS®E on an impedance data I/O code of load losses in watts and impedance magnitude in per unit on winding MVA base (CZ=3) and winding voltage base with taps at nominal position. Taps will be entered using a winding data I/O code of per unit values on a bus voltage base (CW=1).

First, the user should assign windings 1, 2 and 3 to this transformer unit. Let's assume that the user makes the following selection:

Winding 1: H winding – bus I

Winding 2: X winding – bus J

Winding 3: Y winding – bus K

Second, the user enters the tap data:

t_1 = (500/500) = 1.0 pu on a 500 kV bus voltage base

t_2 = (230/230) =1.0 pu on a 230 kV bus voltage base

t_3 =(13.8/13.8) = 1.0 pu on a 13.8 kV bus voltage base

Third, the user enters winding MVA base, winding voltage base, and the three-phase load loss and per unit impedance magnitude from the short circuit test:

$W_{1\text{-}2}$ = 413,800 W, SB1-2 = 217 MVA, VBw1 = 500 kV

$W_{3\text{-}1}$ = 108,500 W, SB3-1 = 51.9 MVA, VBw3 = 13.8 kV

$W_{2\text{-}3}$ = 104,000 W, SB2-3 = 51.9 MVA, VBw2 = 230.0 kV

and,

$|Z_{1\text{-}2}|$ = 0.1324 pu on 217 MVA and 500/230 kV base

$|Z_{3\text{-}1}|$ = 0.1211 pu on 51.9 MVA and 500/13.8 kV base

$|Z_{2\text{-}3}|$ = 0.0806 pu on 51.9 MVA and 230/13.8 kV base

Fourth, the user enters the magnetizing branch data using the magnetizing admittance I/O code of no-load loss in W and exciting current in per unit on $SB_{1\text{-}2}$ and winding voltage base V_{Bw1} (CM=2):

W_{NL} = 108,300 W

I_{ϕ} = $|Y_{exc}|$ = 0.0022 *(130.2/217) pu = 0.00132 pu on 217 MVA and 500 kV base

The PSS®E data record with these data is shown below.

```
101, 104, 103,'1 ', 1, 3, 2, 108300, 0.00367, 1,'3WXFMR ', 1, 1, 1.0000

413800, 0.13240, 217.00, 104000, 0.08060, 51.90, 108500, 0.12110, 51.90, 0.94237,
-10.2892

1.00000, 0.000, 0.000, 217.00, 217.00, 0.00, 0, 0, 1.05000, 0.95000, 1.10000,
0.90000, 5, 0, 0.00000, 0.00000

1.00000, 0.000, 0.000, 217.00, 217.00, 0.00, 0, 0, 1.10000, 0.90000, 1.10000,
0.90000, 0, 0, 0.00000, 0.00000

1.00000, 0.000, 0.000, 51.90, 51.90, 0.00, 0, 0, 1.02500, 0.97500, 1.10000,
0.90000, 3, 0, 0.00000, 0.00000
```

Now, assume that the user wishes to enter the transformer data in per unit on a winding MVA base and winding voltage base (CZ=2). The following computations must be applied before entering the data:

Computation of between winding resistive component R1-2, R3-1 and R2-3 of the between winding impedances Z1-2, Z3-1 and Z2-3:

R1-2 = W1-2/SB1-2 =0.4138/217 = 0.00191 pu on 217 MVA and 500/230 kV base

R3-1 = W3-1/SB3-1 =0.1085/51.9 = 0.00209 pu on 51.9 MVA and 500/13.8 kV base

R2-3 = W2-3/SB2-3 =0.1040/51.9 = 0.00200 pu on 51.9 MVA and 230/13.8 kV base

The reactive component X1-2, X3-1 and X2-3 of the between winding impedances Z1-2, Z3-1 and Z2-3 are computed from the equation

$$X = \sqrt{|z|^2 - R^2}$$

These values are:

X1-2 = 0.13239 pu on 217 MVA and 500/230 kV base

X3-1 = 0.12108 pu on 51.9 MVA and 500/13.8 kV base

X2-3 = 0.08058 pu on 51.9 MVA and 230/13.8 kV base

The magnetizing branch admittance Yexc is entered in per unit on a system MVA base and winding 1 bus voltage base VBw1 (CM=1)

Gm =

WNL/SB1-2 = 0.1083/217 = 0.00050 pu on 217 MVA and 500 kV base

=

0.00050*(217/100) = 0.00108 pu on 100 MVA and 500 kV base

Bm =

(|Yexc|2 – Gm2)1/2 = (0.001322 – 0.000502)1/2 = 0.00364 pu on217 MVA and 500 kV base

=

0.00364*(217/100) = - 0.00789 pu on 100 MVA and 500 kV base

The PSS®E data record with these data is shown below:

```
101, 104, 103,'1 ', 1, 2, 2, 108300, 0.00367, 1,'3WXFMR ', 1, 1, 1.0000

0.00191, 0.13239, 217.00, 0.00200, 0.08058, 51.90, 0.00209, 0.12108, 51.90,
0.94237, -10.2892

1.00000, 0.000, 0.000, 217.00, 217.00, 0.00, 0, 0, 1.05000, 0.95000, 1.10000,
0.90000, 5, 0, 0.00000, 0.00000

1.00000, 0.000, 0.000, 217.00, 217.00, 0.00, 0, 0, 1.10000, 0.90000, 1.10000,
0.90000, 0, 0, 0.00000, 0.00000

1.00000, 0.000, 0.000, 51.90, 51.90, 0.00, 0, 0, 1.02500, 0.97500, 1.10000,
0.90000, 3, 0, 0.00000, 0.00000
```

PSS®E stores the three-winding transformer data on system MVA base and bus voltage base. In addition, the network model used for three-winding transformers is the T-equivalent or star-equivalent network, where the common node of the T or star is a dummy bus created by PSS®E. This bus is transparent to the user because the only terminals available to the device are the output terminals of circuit windings. The winding equivalent impedances Z1, Z2 and Z3 of the T-equivalent network are calculated from the following equations:

Z1 = (1/2)*[Z1-2 +Z3-1 – Z2-3] in pu on system MVA base and 500/230/13.8 kV base

Z2 = (1/2)*[Z1-2 +Z2-3 – Z3-1] in pu on system MVA base and 500/230/13.8 kV base

Z3 = (1/2)*[Z3-1 +Z2-3 – Z1-2] in pu on system MVA base and 500/230/13.8 kV base

Using the data from calculations above the user obtains the following:

Z1 = 0.00053 +j0.06952 pu on a 100 MVA base and 500/230/13.8kV base

Z2 = 0.00035 -j0.00851 pu on a 100 MVA base and 500/230/13.8kV base

Z3 = 0.00350 +j0.16377 pu on a 100 MVA base and 500/230/13.8kV base

The PSS®E output showing these data is shown below:

```
SINGLE MACHINE SYSTEM FOR ILLUSTRATION 3 WINDING XFRMER

0.95 POWER FACTOR WINDING DATA

X- XFRMER -X X----- WINDING BUS -----X S C MAGNETIZING Y SYSTEM BASE NOM. TBL
CORRECTED STAR POINT BUS

X-- NAME --X BUS# X-- NAME --X BASKV T M MAG1 MAG2 R WNDNG X WNDNG RATEA RATEB
RATEC TBL R WNDNG X WNDNG VOLTAGE ANGLE

3WXFMR 101 HVBUS 500.00 1 1 0.00108 -0.00789 0.00052 0.06953 217.0 217.0 0.0
0 0.94237 -10.3

104 LV 230.00* 1 0.00036 -0.00852 217.0 217.0 0.0 0

103 GENBUS 13.800* 1 0.00351 0.16377 51.9 51.9 0.0 0
```

4.8. Transformer Connections

The transformer model derivation above applies to a single-phase two-winding transformer. The concern, though, is the positive-sequence behavior of three-phase transformers or three-phase banks of single-phase transformers.

The simplest three-phase case is shown in Figure 4.20, "Star-Star Grounded Three-Phase Transformer Bank", which uses three identical single-phase transformers in a star-star connection. Because the positive sequence considers balanced operation, and because there is no mutual coupling between phases (phase *a* current has no influence on phases *b* and *c*, and so on), each phase can be modeled independently as a simple two-winding transformer. A re-application of the phase-to-sequence transformation as in Section 2.3.3, "Branch Impedances in Terms of Symmetrical Components" will then show that the transformer's behavior in each sequence is the same as that of one of the phase transformers. (This can be seen easily by letting $Z_m = 0$ in (1.16)). Hence the per-unit impedance of one of the three single-phase transformers shown in Figure 4.20, "Star-Star Grounded Three-Phase Transformer Bank" can be used directly in Equation 4.2, Equation 4.9, and Equation 4.15 to get data for the positive-sequence model of Figure 4.3, "Standard Per-Unit Form Transformer Equivalent Circuit".

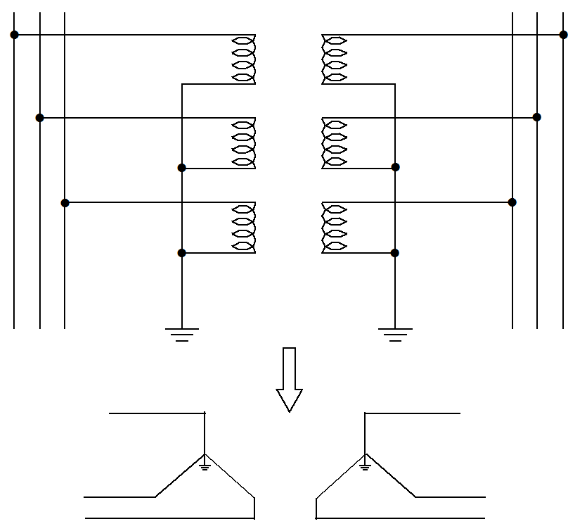


Figure 4.20. Star-Star Grounded Three-Phase Transformer Bank

The number of ways in which transformers can be constructed and connected to provide balanced three-phase operation is huge. The number of ways in which transformer data are stated in nameplates and manuals is even greater. Accordingly, there can be no standard way of deriving positive-sequence impedance and tap ratio data from nameplates and other sources. Some nameplates are very comprehensive and give winding diagrams, impedances in ohms, and details of tapping. Others leave nearly everything to the imagination of the observer. Some nameplates of individual-phase transformers state per-unit data for the bank that will be built up from three of these transformers. It needs to be emphasized that the accurate modeling of transformers depends upon the engineer's proper interpretation of the nameplate or other available data. The computer programs making system simulations assume that Figure 4.3, "Standard Per-Unit Form Transformer Equivalent Circuit" is an accurate representation of the transformer and will give accurate results if the user has properly derived the values of winding 1 per-unit tap ratio, *t1*, (including $t1_{max}$, $t1_{min}$, and n_{steps}) and per-unit impedance, x_{eq}, from original equipment data.

4.9. Transformer Phase Shift

Many three-phase transformer connections create a phase shift between primary and secondary voltages. The most common phase-shifting connection is the standard delta-wye arrangement shown in Figure 4.21, "Delta-Wye Transformer Bank". This figure illustrates the winding arrangement of a delta-wye transformer, an equivalent three-phase circuit diagram, and the relationship of the phase-to-neutral voltages on the transformer's primary and secondary voltage.

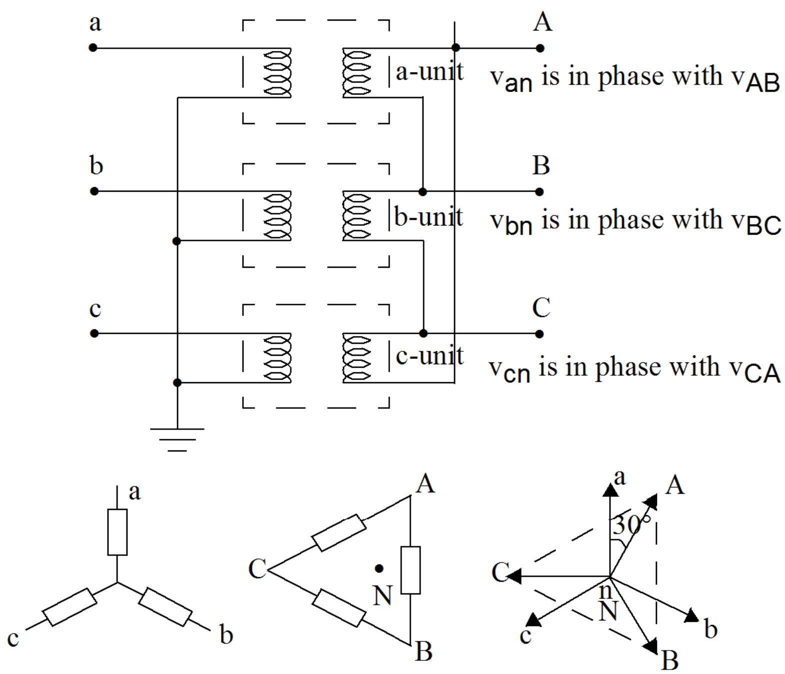


Figure 4.21. Delta-Wye Transformer Bank

Applying balanced positive-sequence voltages, v_{abc}, to the wye-winding produces the phase-to-phase voltages v_{ABC} in the delta-winding. The resulting phase-to-neutral voltages on the delta-connected side lag those on the wye side by 30 degrees.

Analytical representation of this effect in the positive sequence may be obtained by replacing the delta-connected set of windings with an equivalent star-connected set where the number of turns in each phase is the complex number

$|t| \angle (-\pi / 6)$

Replacing the real number, *t*, with this complex number throughout the derivation of the transformer model results in the equivalent circuit shown in Figure 4.22, "Transformer Equivalent Circuit Representing Phase Shift". This circuit is identical to Figure 4.3, "Standard Per-Unit Form Transformer Equivalent Circuit", except that the per unit equivalent turns ratio is a complex number. The value of the phase shift, θ, is constant at $\pi/6$ radians as the value of $| t |$ is adjusted by changing taps.

The equivalent circuit of Figure 4.22, "Transformer Equivalent Circuit Representing Phase Shift" may be used to represent adjustable phase shifters. These units use tapped zigzag-connected windings to produce an adjustable phase shift between primary and secondary windings. The equivalent turns ratio, | t |, may be either constant or variable as the phase shift is altered, depending on the design of the specific unit.

PSS®E allows the user to specify both the amplitude winding ratios, | $t1$ | and | $t2$ |, and phase shift, θ , of every transformer. The phase shift angle θ is the angle by which winding 1 leads winding 2. All solutions are based on the equivalent circuit of Figure 4.22, "Transformer Equivalent Circuit Representing Phase Shift", and hence are accurate as long as the conditions of Section 4.1.2, "Transformer Equivalent Circuit Summary" are observed.

The PSS®E power flow solutions include logic for automatic adjustment of both t and θ . It must be noted that the automatic adjustment of t does not alter θ and, more importantly, that PSS®E assumes that t is independent of adjustments of θ .

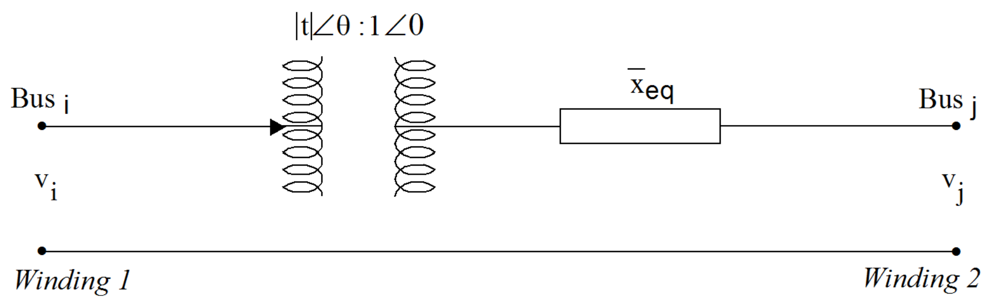


Figure 4.22. Transformer Equivalent Circuit Representing Phase Shift

Chapter 5

Power System Network Simulations

5.1. Power Flow Calculations

The most common power system network simulation is the power flow calculation, described in the following question:

Given the load power consumption at all buses of the electric power system and the generator power production at each power plant, find the power flow in each line and transformer of the interconnecting network.

Calculated answers to this question are the basic means by which the power system is engineered to serve its load, while incurring capital and operating costs in the optimum ratio to one another. The power system must operate without overloading transmission lines or transformers, stay within acceptable voltage limits at all buses, and maintain generator reactive power outputs between acceptable limits.

The power flow problem pertains to balanced steady-state operation of the power system. Because it considers balanced operation in which all negative- and zero-sequence voltages are zero, the power flow calculation deals with the *positive-sequence* model of all system components.

The following are the basic known input data for power flow calculations:

- Transmission line impedances and charging admittances.
- Transformer impedances and tap ratios.
- Admittances of shunt-connected devices such as static capacitors and reactors.
- Load-power consumption at each bus of the system.
- Real power output of each generator or generating plant.
- Either voltage magnitude at each generator bus or reactive power output of each generating plant.
- Maximum and minimum reactive power output capability of each generating plant.

The quantities to be determined are

- The magnitude of the voltage at every bus where this is not specified in the input data.
- The phase of the voltage at every bus.
- The reactive power output of each plant for which it is not specified.
- The real power, reactive power, and current flow in each transmission line and transformer.

The power flow calculation is a network solution problem. The network of transmission lines and transformers is described by the linear algebraic equation

$$I_n = Y_{nn} V_n \tag{5.1}$$

where

I_n

Vector of positive-sequence currents flowing into the network at its nodes (buses).

V_n

Vector of positive-sequence voltages at the network nodes (buses).

Y_{nn}

Network admittance matrix.

If either I_n or V_n is known, the power flow calculation is straightforward. In practice, neither I_n nor V_n is known and the task of the power flow program is to devise successive trials of both I_n and V_n such that they satisfy both Equation 5.1 and all the load and generation conditions specified in the problem data. After V_n has been determined, all individual transmission line and transformer flows can be obtained directly from the component equations as summarized in The Per-Unit Data System and Transformers in the Positive-Sequence.

5.2. The Network Admittance Matrix

Consider a bus, *i*, of a power network which connects two transmission lines, two transformers, and a shunt element as shown in Figure 5.1, "Equipment Connected at Bus, *i*". Note that bus *i* is connected only to buses *j*, *k*, *m*, and *n*. Note also, the designation of the tap-changing side of each transformer.

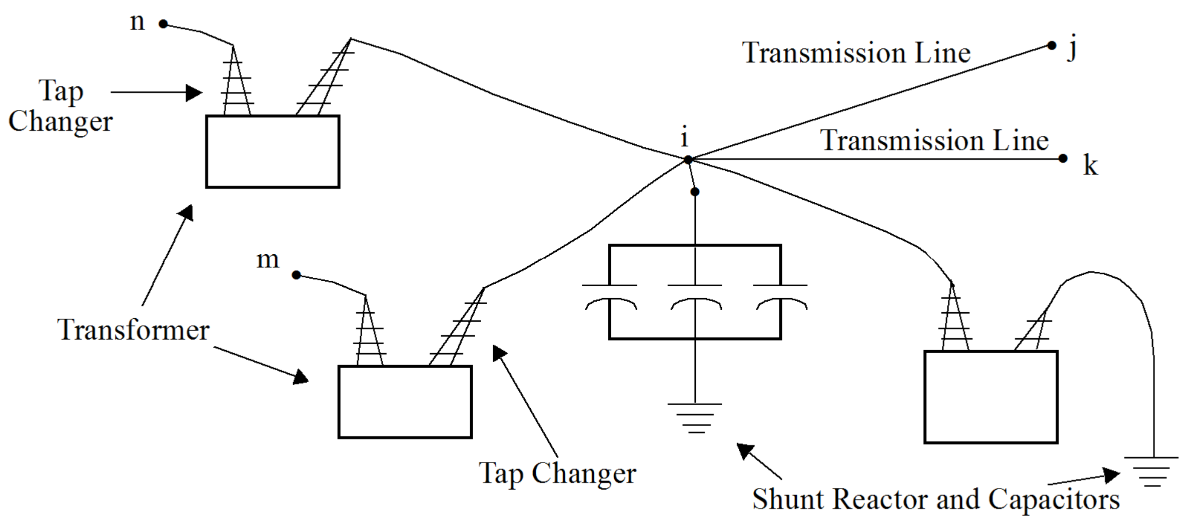


Figure 5.1. Equipment Connected at Bus, i

Each line and transformer may be represented by a per-unit equivalent circuit as shown in Figure 2.17, "Pi-Form Transmission Line Equivalent Circuit" and Figure 4.19, "Three-Winding Transformer Representation with Equipment on Tertiary Winding", with per-unit parameters being calculated from spacing, length, and nameplate data with respect to a common system MVA base. The resulting equivalent circuit surrounding network node, *i*, which represents bus *i* in the equivalent circuit of the whole system, is shown in Figure 5.2, "Equivalent Circuit for Node *i* of Transmission Network Positive-Sequence Model".

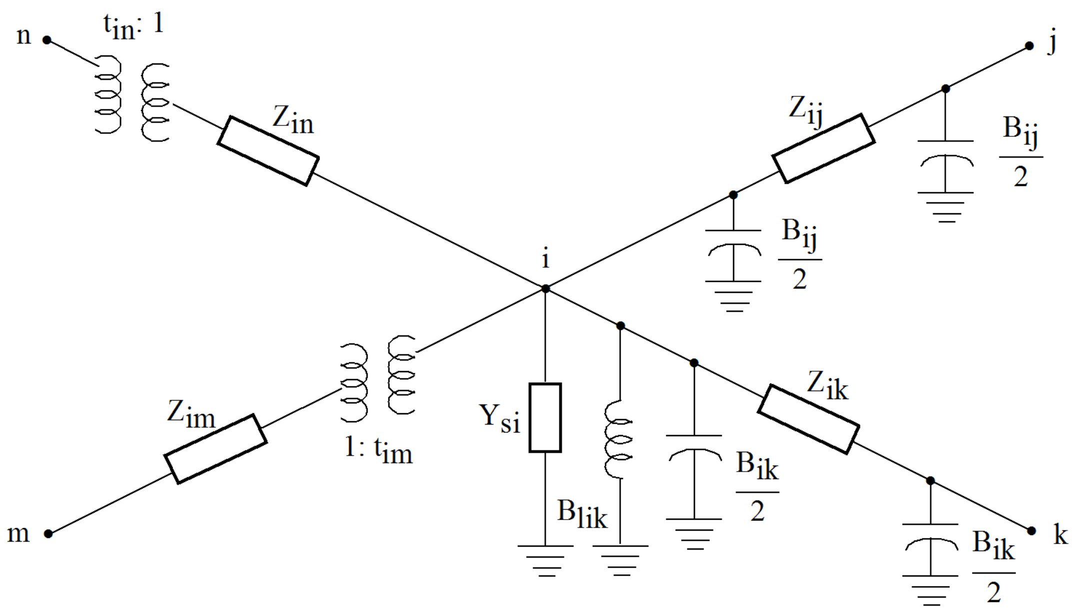


Figure 5.2. Equivalent Circuit for Node i of Transmission Network Positive-Sequence Model

The total current, i_i, flowing into node *i* when voltages, v_i, v_j, v_k, v_m, and v_n are applied to the network may be determined by adding up the flow into each leg of Figure 5.2, "Equivalent Circuit for Node *i* of Transmission Network Positive-Sequence Model" at its connection to node *i*.

Hence

$$\begin{aligned} i_i \;=\; & v_i Y_{si} \\ & + (v_i - v_j) / z_{ij} + \frac{v_i B_{ij}}{2} \\ & + (v_i - v_k) / z_{ik} + \frac{v_i B_{ik}}{2} + v_i B_{lik} \\ & + \left(\frac{v_i}{t_{im}} - v_m \right) / (z_{im} t_{im}) \\ & + \left(v_i - \frac{v_n}{t_{in}} \right) / (z_{in}) \end{aligned} \tag{5.2}$$

Expansion of Equation 5.1 for the *i*-th element of I_n, which is i_i, gives

$$i_i = \Sigma .y_{ih} v_h \tag{5.3}$$

where

Y_{ih} are the elements of Y_{nn}

and

v_h are the elements of the node voltage vector, v_n

The expressions for the elements, y_{ih}, in terms of transmission line and transformer parameters can be found by collecting terms in Equation 5.2 and comparing the result with Equation 5.3. The construction of the individual elements, y_{ii}, of the network admittance matrix from the line and transformer data is a key section of all power flow solution procedures of PSS®E.

Examination of Equation 5.2 shows that only the diagonal element, y_{ii}, and four off-diagonal elements, y_{ih}, of the *i*-th row of the admittance matrix are nonzero. That is, a line or transformer from bus *i* to bus *j* contributes nonzero elements only to the *i*-th and *j*-th rows of Y_{nn}. Realistic power systems have between 1.5 and 2 transmission lines or transformers for each node. A transmission network of 2000 buses might, therefore, be expected to have approximately 4000 branches and, correspondingly, 8000 nonzero off-diagonal elements in its admittance matrix. This typical bus-to-branch ratio results in very sparse admittance matrices. In the above example only 8000 out of 2000 (2000-1), or 0.2%of the off-diagonal elements of Y_{nn} are nonzero.

The great majority of modern power flow calculation programs, including those of PSS®E, take advantage of this sparsity in their management of computer storage. They also take advantage of procedures that allow the admittance matrix to be manipulated into triangular factor and partial inverse forms that have similar sparsity properties, but where the number of nonzero off-diagonal elements is typically two to three times the number of such elements in the original Y_{nn} matrix.

Presenting a power flow program with a power system network model where the original Y_{nn} matrix (or derivatives therefrom) has a number of nonzero elements that exceed the program's allocated capacity, results in an error condition that prevents the use of some, but not all, of the available power flow iteration algorithms.

5.3. Iterative Solution Algorithms

The power flow problem is nonlinear and requires an iterative trial and error process for its solution. One simple but effective iterative scheme follows:

1. Make an initial estimate of the voltage at each bus.
2. Build an estimated current inflow vector, I_n, at each bus from a boundary condition, such as

$$P_k + j\,Q_k = v_k\, i_k^* \tag{5.4}$$

   where:

   Pk + j Qk

   Net load and generation demand at bus k.

   vk

   Present estimate of voltage at bus k.

3. Use Equation 5.1 to obtain a new estimate of the bus voltage vector, v_n.
4. Return to Step 2 and repeat the cycle until it converges on an unchanging estimate of v_n.

While this scheme is useful in some specific situations (to be discussed later), it does not work well for the general power flow calculation where the terminal voltage magnitude, rather than reactive power output, is specified for many generators.

The range of iteration schemes that have been devised for the power flow calculation is seemingly endless, and largely academic. PSS®E allows the user to choose from five different AC power flow iteration schemes:

1. Gauss-Seidel iteration.
2. Modified Gauss-Seidel iteration suitable for series capacitors.
3. Fully coupled Newton-Raphson iteration.
4. Decoupled Newton-Raphson iteration.
5. Fixed slope Decoupled Newton-Raphson iteration.

5.4. Network and Boundary Conditions

Steps 2 and 3 of the iterative scheme in Section 5.3, "Iterative Solution Algorithms" refer to two aspects of the power flow solution calculation. The solution of the power flow problem is a set of bus (or node) voltages that simultaneously satisfy the network condition, $I_n = Y_{nn} v_n$, derived from Kirchhoff's laws, and the boundary conditions derived from load and generator characteristics, such as $P_k + jQ_k =$

$$v_k i_k^*$$

.

The network condition Equation 5.1 is linear and can be solved without iteration if either the voltage vector, v_n, or the current vector, I_n, is specified. The solution is a direct calculation if v_n is specified, and requires a standard computer procedure for solving linear simultaneous equations if I_n is given.

The boundary conditions may be specified quite arbitrarily, depending upon the loads that electricity users choose to connect to the network, and are usually nonlinear. It is the nonlinearity of the boundary conditions that forces the use of an iterative procedure for power flow solution. It must be noted though, that while the network condition *can* be handled in a noniterative, closed-form manner, it is often advantageous to use an iterative method to solve both the network condition and the boundary conditions.

Of the five power flow iteration procedures provided in PSS®E:

- The Gauss-Seidel and Modified Gauss-Seidel methods solve both network and boundary conditions by iteration.
- The full Newton-Raphson and both Decoupled Newton-Raphson methods solve the network condition by closed-form calculation, while using iteration to solve the boundary conditions.

5.5. Steady-State Boundary Conditions

5.5.1. Loads

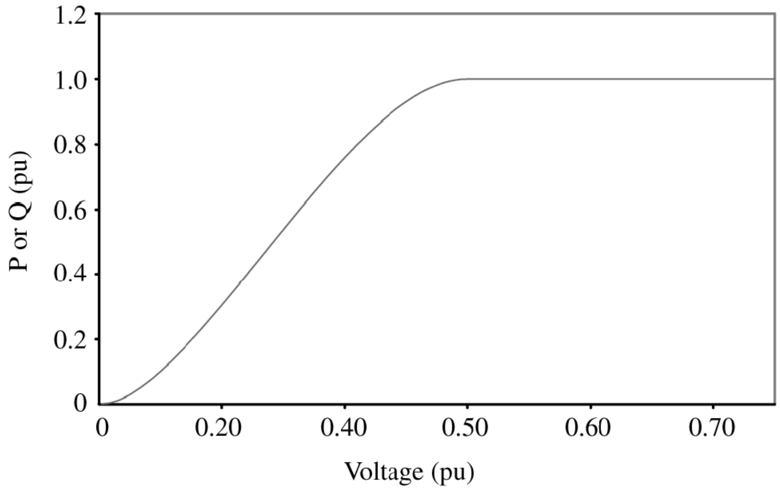
Constant MVA

The most common load boundary condition is a specification of load real and/or reactive power consumption

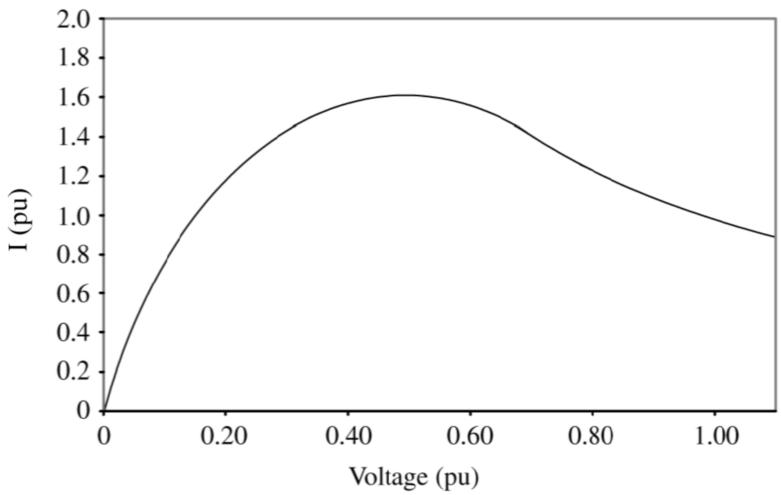
$$\mathrm{Real}\,(v_k\, i_k^*) = -P_k \tag{5.5}$$

$$\mathrm{Imag}\,(v_k\, i_k^*) = -Q_k \tag{5.6}$$

This characteristic is not realistic for voltages below approximately 0.8 per unit. All PSS®E power flow voltage solutions, in both power flow and dynamic simulation, therefore, modify Equation 5.5 and Equation 5.6 to make P_k and Q_k functions of the magnitude of the bus voltage as shown in Figure 5.3, “Constant MVA Load Characteristic and Resultant Form of Current/Voltage Curve”. The switch voltage, v_{exm}, may be specified by the user of PSS®E; a single value applies to the entire power system model.



a. Constant MVA Load Characteristic



b. Current/Voltage Curve

Figure 5.3. Constant MVA Load Characteristic and Resultant Form of Current/Voltage Curve

Constant Current

Load may be specified as a given active or reactive component of current such that

$$\frac{\mathrm{Real}\,(v_k\, i_k^*)}{|\, v_k \,|} = -\, I_{pk} \qquad (5.7)$$

$$\frac{\mathrm{Imag}\,(v_k\, i_k^*)}{|\, v_k \,|} = -\, I_{qk} \qquad (5.8)$$

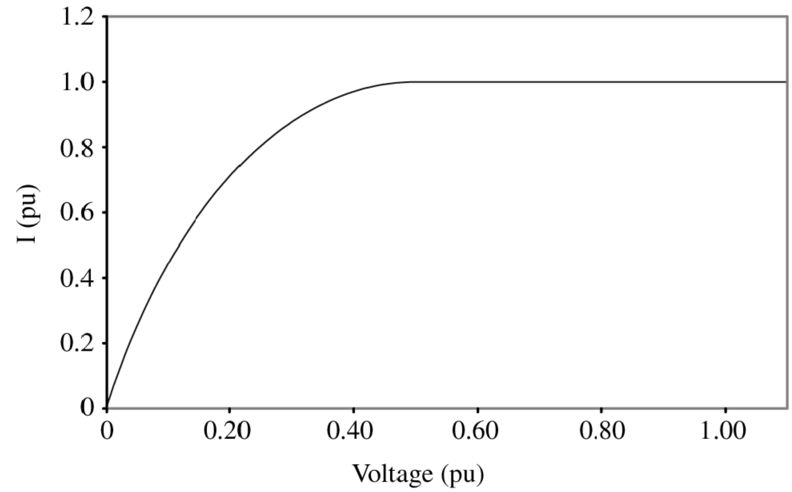
Again, because this characteristic is unrealistic for voltages below about 0.5 per unit, all PSS®E power flow solutions modify Equation 5.7 and Equation 5.8 to make I_{pk} and I_{qk} functions of the magnitude of v_k, as shown in Figure 5.4, “Constant Current Load Characteristic and Resultant Form of Load MVA/Voltage Curve”.

Constant Impedance

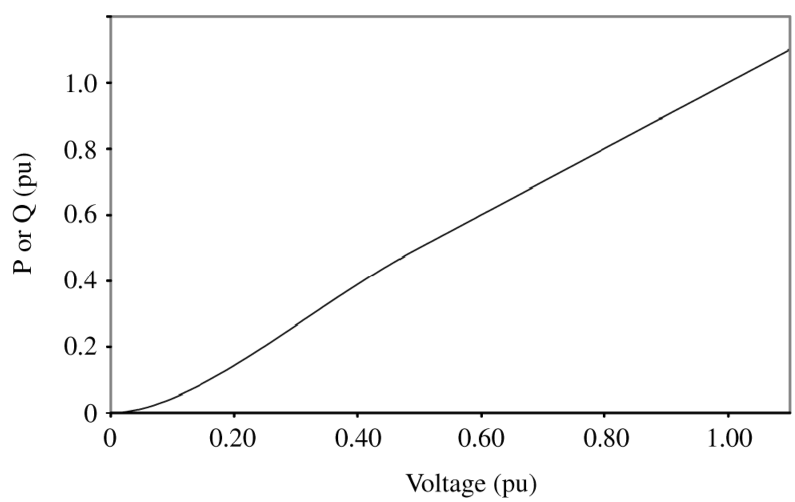
Finally, load may be specified by given real and reactive parts of shunt admittance such that

$$\frac{i_k}{v_k} = G_k + jB_k \tag{5.9}$$

Note that Equation 5.9 is not treated as a boundary condition in the solution process; it is more convenient to incorporate the shunt branch into the network model as covered in Section 5.2, “The Network Admittance Matrix”.



a. Constant Current Load Characteristic



b. Load MVA/Voltage Curve

Figure 5.4. Constant Current Load Characteristic and Resultant Form of Load MVA/ Voltage Curve

Composite Load

All PSS®E network solutions allow the load at each bus to be a composite of arbitrary amounts of load with each of the above three characteristics. The composite characteristic becomes the boundary condition used in iterative power flow solutions. The adjustment of load data to vary the fraction of the total having each characteristic is handled by interactive dialog. The normal practice is to specify the load at each bus initially as a compendium of constant MVA and constant admittance loads. A part of the constant MVA load can then be reassigned as constant current load at any time by the use of activity CONL. This course gives compatibility with external power flow data formats such as the IEEE Common Format.

Swing Bus

Every power flow simulation case must have at least one bus designated as a *swing bus*. The corresponding boundary condition is

$v_{k(complex} =$ constant

The net real and reactive power inflow to a swing bus are free variables and follow from the power flow solution, rather than being boundary conditions imposed upon it.

Power flow solution cases must have at least one swing bus in every separate section of the network. No swing bus is needed in fault analysis, switching, and dynamic simulation calculations, although swing buses may be used in these simulations.

The user can check that every subsystem of a power system power flow case includes a swing bus by executing TREE.

Special Boundary Conditions

Several special boundary conditions are recognized in certain PSS®E activities to handle the behavior of specific items of equipment. Power flow solutions, for example, recognize the special and complicated boundary conditions imposed by DC transmission converters, while the dynamic simulation activities are able to recognize the boundary conditions imposed by specific loads such as induction motors and static reactive power sources.

Each of these miscellaneous boundary conditions is discussed in the section where the applicable equipment is discussed.

5.5.2. Generator Power Flow Boundary Conditions

General Treatment

The standard generator arrangement used throughout PSS®E is shown in Figure 5.5, "Standard PSS®E Generator Configuration", and the corresponding data items are listed in Table 5.1, "Generator Parameters and Data". The generator is assumed to be connected to bus *k* by a step-up transformer where the impedance is Z_t, ($R_t + jX_t$), per unit on generator MVA_{base}. The transformer impedance may be set to zero to model a generator connected directly to the bus.

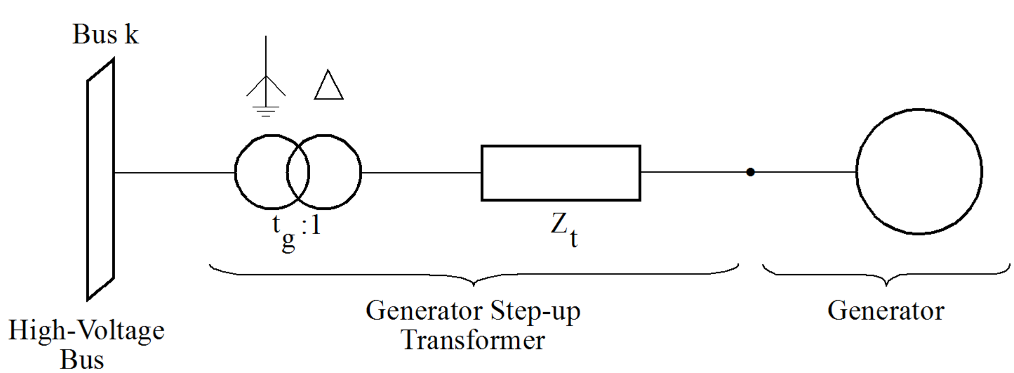


Figure 5.5. Standard PSS®E Generator Configuration

Table 5.1. Generator Parameters and Data

Quantity	Name	Units
Reactive Power Output at Bus *k*	QGEN	Mvar
Maximum Reactive Power Output at Bus *k*	QMAX	Mvar
Minimum Reactive Power Output at Bus *k*	QMIN	Mvar
Generator Base MVA	MBASE	MVA
Step-up Transformer Tap Position on Bus *k* Side	GENTAP	Per unit
Step-up Transformer Impedance	ZTRAN	Per unit based on MBASE
Generator Dynamic Impedance	ZSORCE	Per unit based on MBASE
Alternative Generator Dynamic Impedance	ZPOS	Per unit based on MBASE
Maximum Real Power Output at Bus *k*	PMAX	MW
Minimum Real Power Output at Bus *k*	PMIN	MW

The standard generator boundary condition is a specification of real power output at the high-voltage bus, bus *k*, and of voltage magnitude at some designated bus, not necessarily bus *k*.

$$\mathrm{Real}\,(v_k i_k^*) = P_k \tag{5.10}$$

$$|v_1| = V_{sched} \tag{5.11}$$

This characteristic is subject to a reactive power output limitation

$$Q_{min\ k} \le \mathrm{Imag}\,(v_k i_k^*) \le Q_{max\ k} \tag{5.12}$$

which overrides the voltage schedule condition Equation 5.11.

It is important to recognize that the maximum and minimum reactive power limits assigned to bus *k* apply to generator reactive power output measured at the high-voltage bus and not at the generator terminals. Determination of $Q_{min\ k}$ and $Q_{max\ k}$ must, therefore, recognize the reactive power loss in the step-up transformer reactance. A reasonable assumption for assigning reactive power limits to bus *k*, in this situation, is to subtract a reactive loss corresponding to full load current from the generator terminal reactive power limits. Because Z_t has a per-unit value with respect to generator MVA base and $Q_{min\ k}$, $Q_{max\ k}$ are in megavars,

$$Q_{limit\ k} = Q_{limit\ g} - X_t \times \mathrm{MBASE} \tag{5.13}$$

for lagging generator terminal power factor, and

$$Q_{limit\ k} = Q_{limit\ g} + X_t \times \mathrm{MBASE} \tag{5.14}$$

for leading generator terminal power factor, where

Xt

Step-up transformer reactance in per unit on generator base.

Qlimit g

Limiting reactive power in Mvar at generator terminals.

Qlimit k

$Q_{min\ k}$ or $Q_{max\ k}$.

Multiple Identical Generators

Multiple, identical generators may be represented by the standard model, as shown in Figure 5.5, “Standard PSS®E Generator Configuration”, by specifying the generator MVA base to be the total MVA rating of all connected generators and specifying Z_t as the impedance of a single step-up transformer on its own single generator rating. This representation is illustrated by Figure 5.6, “Identical Generators at Bus”.

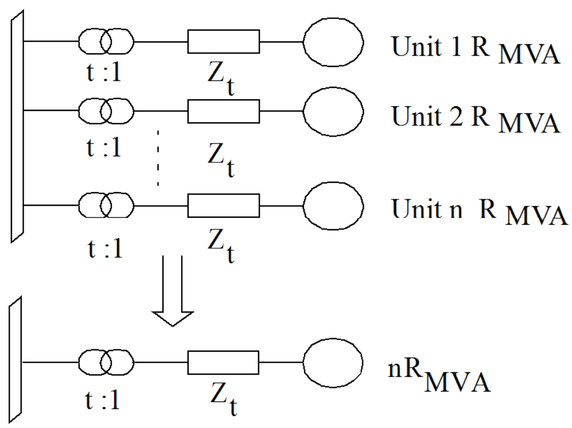


Figure 5.6. Identical Generators at Bus

Lumping several identical generators (see Figure 5.6, “Identical Generators at Bus”) may, for example, be used in the case of hydro plants. Startup and shutdown of units as plant load increases and decreases can be accounted for by an adjustment of P_{gen}, $Q_{max\ k}$, $Q_{min\ k}$, and $MBASE_k$. No adjustment of Z_t or of the network branch data is necessary.

Use of this lump approach to handle multiple units implies that real and reactive power output are distributed uniformly between them. If loadings of multiple units are not identical, they must be treated as different generators even though their impedances and other characteristics are identical. Multiple identical generators may also be represented as multiple generators at the bus as outlined in Section 6.9.5, “Generating Plants”. This offers the advantage of having to change only unit status flags to account for a change in the number of operating units at the plant.

Bus With Several Different Generators

A plant having several different generators connected to its high voltage bus cannot be represented by a single generator model such as the one shown in Figure 5.5, “Standard PSS®E Generator Configuration”. Correct representation of such plants requires the use of multiple generator models at the bus as outlined in Section 6.4.5 Generating Plants.

5.6. Dynamic Boundary Conditions

5.6.1. Categories of Network Solution

The voltage versus current characteristics of synchronous generators are different in different time regimes. Power system network solutions must, therefore, be categorized according to the conditions just before and at the instant for which the solution is to apply. The time regimes of significance in network solutions are illustrated in Figure 5.7, "Time Regimes Considered in Power System Simulations".

All power system simulations assume that the system is in the steady state for an extended period prior to the time, *t*. It is assumed that the first incident of interest, such as a switching operation, fault, load change, or control setpoint change, occurs at, *t*. Power flow calculations apply to the instant, t^-. The power flow generator boundary conditions, as stated in Section 5.5.2, "Generator Power Flow Boundary Conditions ", therefore assume that the system is in the steady state, or more practically, experiencing the gentle motions of normal undisturbed operation. Every power flow calculation establishes the condition of the entire transmission network, outward from generator terminals to load terminals, for an instant, t^-.

Any switching operation, fault, significant load change or change of control inputs (governor or excitation system reference) starts the system moving. All simulations considered in this book assume that transients in the electric network die away very rapidly in relation to the time durations of the transients that are of interest. The power frequency phasors representing currents and voltages throughout the network are assumed to change instantaneously at *t*.

The transients of the flux linkages in the rotors of electrical machines are of prime interest and must be accurately accounted for. Simulations of conditions at, t^+, and later must, therefore, use boundary conditions that recognize dynamic, rather than steady-state, behavior of equipment. Both generator and load characteristics applicable to t^+ are different from those applying at t^-. Loads are commonly assumed to have a constant MVA steady-state characteristic in steady-state power flow solutions applying to t^-, but to be better modeled by a mixture of constant current and constant impedance characteristics at t^+ and later.

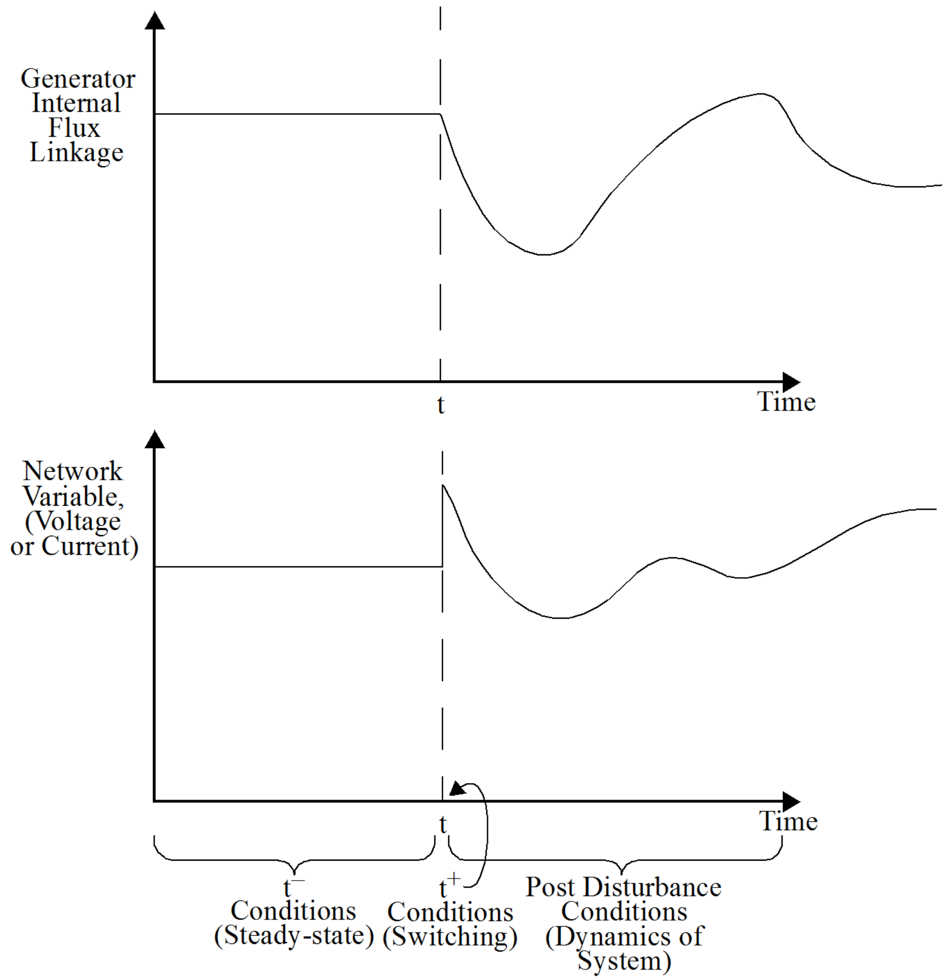
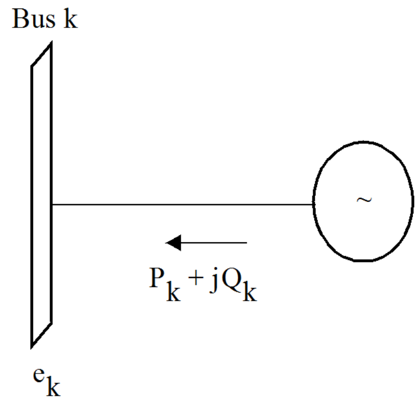


Figure 5.7. Time Regimes Considered in Power System Simulations

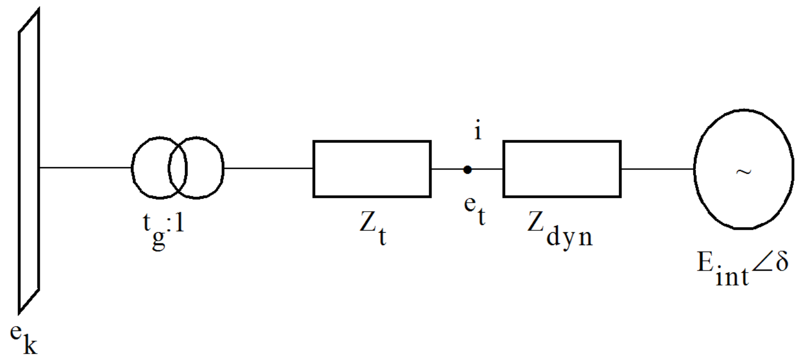
The generator boundary conditions applying at instants, t^- and t^+, are illustrated by Figure 5.8, "Generator-Network Coupling Models for Power Flow, Switching, and Dynamic Simulation Calculations". The t^- boundary condition is as given in Section 5.5.2, "Generator Power Flow Boundary Conditions". The t^+ boundary condition recognizes that generator rotor flux linkages must obey Lenz's and Maxwell's laws.

The instantaneous change caused by a switching is followed by a period when all generator flux linkages, rotor angular positions, and other power plant quantities vary, as dictated by the differential equations governing their dynamic behavior.

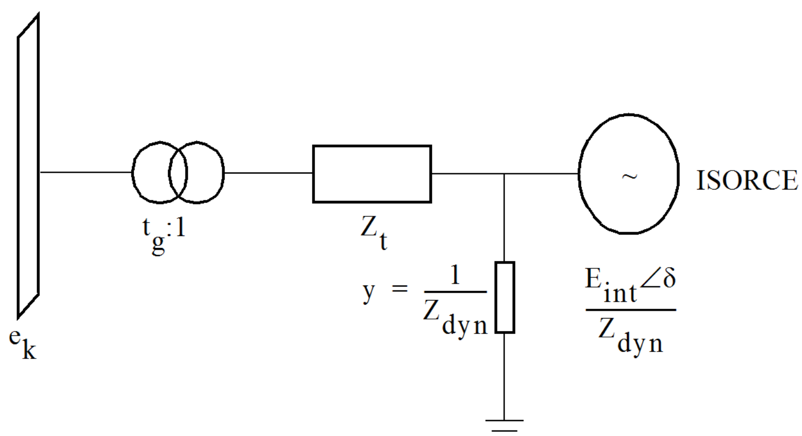
The power flow database of PSS®E allows the entry of generator and load data pertaining to pre-disturbance conditions at t^-, to switching conditions at t^+, and to system dynamic behavior over an arbitrarily long period after the initiation of the disturbance. The user of PSS®E may then obtain a solution for any of the three time regimes, *steady-state*, *switching*, or *dynamic behavior*, by executing appropriately selected sequences of PSS®E activities.



a. Standard Power Flow Model



b. Thevenin Generator Equivalent for Switching and Dynamic Simulation Calculations



c. Norton Generator Equivalent for Switching and Dynamic Simulation Calculations

Figure 5.8. Generator-Network Coupling Models for Power Flow, Switching, and Dynamic Simulation Calculations

5.6.2. Positive-Sequence Representation of Generators

Switching, or t^{+}, solutions and dynamic simulations require the generator boundary conditions to be set in accordance with the electromagnetic laws governing rotor flux linkages. The power flow boundary condition of the section called "General Treatment", in which power output and bus voltage are specified, must be replaced by a specification of a Thevenin or Norton source where the instantaneous value is determined by instantaneous values of flux linkages. The positive-sequence generator treatments used throughout PSS®E are shown in Figure 5.8, "Generator-Network Coupling Models for Power Flow, Switching, and Dynamic Simulation Calculations".

Figure 5.8, "Generator-Network Coupling Models for Power Flow, Switching, and Dynamic Simulation Calculations"a shows the standard power flow representation, in which the voltage, e_k, (or voltage at some other bus), P_k, and Q_k are interrelated by the boundary condition of Section 5.5.2, "Generator Power Flow Boundary Conditions ". Bus *k*, as shown in Figure 5.8, "Generator-Network Coupling Models for Power Flow, Switching, and Dynamic Simulation Calculations"a, may be a generator terminal bus, the high-voltage bus of a power plant, or any other bus at which the standard generator boundary condition is to apply. The most common and convenient practice is to make bus *k* the plant high-voltage bus, because voltage at this bus is of most interest in transmission system studies.

The generator representation applicable to switching and dynamic simulation solutions is shown in Figure 5.8, "Generator-Network Coupling Models for Power Flow, Switching, and Dynamic Simulation Calculations"b. Conditions at bus *k* and at the generator terminal point, *i*, are unconstrained and, instead, the amplitude and phase of the Thevenin equivalent source are fixed. These amplitude and phase values may be determined either by a preswitching (t^{-}) power flow solution or by the detailed generator electrodynamic model of a dynamic simulation. The Thevenin equivalent circuit of Figure 5.8, "Generator-Network Coupling Models for Power Flow, Switching, and Dynamic Simulation Calculations"b, while convenient for discussion, is inefficient for calculation and is replaced throughout PSS®E by the exactly equivalent Norton equivalent circuit shown in Figure 5.8, "Generator-Network Coupling Models for Power Flow, Switching, and Dynamic Simulation Calculations"c. The amplitude and phase of the Norton equivalent current, ISORCE, are the specified quantities in switching and dynamic simulation solutions.

The transformer impedance, transformer ratio, and generator dynamic impedance shown in Figure 5.8, "Generator-Network Coupling Models for Power Flow, Switching, and Dynamic Simulation Calculations" are regarded as generator parameters throughout PSS®E and are specified in input data along with the generator real power output and reactive power limits. With the exception of real and reactive power and reactive power limits, all generator parameters are specified per unit with respect to generator base MVA. Generator base MVA is, itself, an input data item.

Generators are treated throughout PSS®E power flow activities as shown in Figure 5.8, "Generator-Network Coupling Models for Power Flow, Switching, and Dynamic Simulation Calculations"a. Their treatment may be switched to that shown in Figure 5.8, "Generator-Network Coupling Models for Power Flow, Switching, and Dynamic Simulation Calculations"c by the execution of activity CONG.

5.7. Convergence Characteristics

The convergence characteristics of iterative solutions of the network condition and of the boundary condition are quite different from one another. Because the network condition is linear, its iterative solution is dependent upon the numerical values of the elements of the network admittance matrix, Y_{nn}, but it is largely independent of the estimates of node voltages and of the load characteristics. The iterative solution of the boundary conditions, in contrast, has convergence characteristics that are strongly dependent on both the node voltage estimates and the load characteristics, but relatively insensitive to the numerical values of network admittances.

Certain combinations of branch impedances will cause the network solution aspect of the Gauss-Seidel iterations to diverge, regardless of the system loading or voltage estimates. When applied to power flow cases containing these combinations, the Gauss-Seidel methods will diverge even if presented with initial starting voltage estimates that are very close to an exact solution. Such power flow cases must be solved with the Newton-Raphson iterations where the convergence characteristics are much less dependent upon network admittances.

The Newton-Raphson iterations will often fail to converge, or diverge, when applied to power flow cases in which the initial node voltages are a poor approximation to the true solution, even though they would converge well if presented with good initial node voltage estimates. In these situations the proper course is to refine the poor initial node voltage estimates by a few iterations of a Gauss-Seidel method before applying a Newton-Raphson iteration.

5.8. Selection of Iterations Scheme

5.8.1. Power Flow

Because their convergence properties are dependent upon network and load attributes, each of the five power flow iteration methods of PSS®E has its own strengths and weaknesses. The most significant strengths and weaknesses are summarized in Table 5.2, "Power Flow Solution Activities—Selection Guide".

Any of these five methods can fail to converge on the solution of some problems. It is rare, however, to find a problem where the correct voltage solution vector, V_n, cannot be found by the application of one or more of the five methods. There are many problems that are difficult or impossible to solve with a single iterative method but which can be solved readily by the successive application of more than one method.

A general guide to the selection of an iterative method follows:

- The Gauss-Seidel methods are generally tolerant of power system operating conditions involving poor voltage distributions and difficulties with generator reactive power allocation, but do not converge well in situations where real power transfers are close to the limits of the system.
- The Newton-Raphson methods are generally tolerant of power system situations in which there are difficulties in transferring real power, but are prone to failure if there are difficulties in the allocation of generator reactive power output or if the solution has a particularly bad voltage magnitude profile.
- The Gauss-Seidel methods are quite tolerant of poor starting voltage estimates, but converge slowly as the voltage estimate gets close to the true solution.
- The Newton-Raphson methods are prone to failure if given a poor starting voltage estimate, but are usually superior to the Gauss-Seidel methods when the voltage solution has been brought close to the true solution.

Table 5.2. Power Flow Solution Activities—Selection Guide

Activity/ Iteration Method	Advantages	Disadvantages	Use When	Do Not Use When	Convergence Monitor	Interrupt Options
SOLV Gauss-Seidel Iteration	Tolerant of data errors, insoluble conditions in local areas of network. Fails gently, indicates areas of network causing problem.	Cannot handle negative series reactances. Acceleration factor must be tuned to match system for optimum performance. Number of iterations increases as system size increases.	Initial voltage estimates are poor. Network has reactive power problem. NSOL or FNSL has failed to converge. Data is suspect.	Network has series capacitors or very low impedance branches.	Prints bus number of bus having largest Δ V each iteration together with / Δ V/ and rectangular components of Δ V. / Δ V/ is printed as multiple of solution tolerance.	S AB to stop iterating and return directly to activity selector. S NC to suppress convergence monitor listing. S DC to print DC line operating parameters at each iteration. S NM to suppress adjust-

Activity/ Iteration Method	Advantages	Disadvantages	Use When	Do Not Use When	Convergence Monitor	Interrupt Options
						ment monitors.
MSLV Modified Gauss-Seidel Iteration	Has most advantages of SOLV and is able to handle series capacitors between Type 1 buses.	Convergence is very sensitive to tuning of acceleration factor, ACCM. Slight deviation of ACCM from optimum. Value gives poor convergence.	As for SOLV.	Network has very low impedance branches, series compensation exceeding about 80%, or series capacitors connected directly to generator buses.	As for SOLV.	As for SOLV.
FNSL Full Newton-Raphson Iteration	Rapid convergence on well-conditioned cases. Small bus mismatches can be achieved.	Intolerant of data errors. Cannot start from poor voltage estimates. No indication of cause of problem when failing to converge. Can give problems converging cases where reactive power limits are restrictive.	Network is conventional and well-behaved. Network contains series capacitors or other negative series reactance branches.	Overloading has produced reactive power problems.	Prints largest mismatch (real and reactive) and voltage changes (magnitude and angle) for each iteration. Identifies the bus numbers where these maxima occur.	As for SOLV.
NSOL Newton-Raphson method with real and reactive power equations decoupled	Rapid convergence on well-conditioned cases. Small bus mismatches can be achieved.	Intolerant of data errors. Cannot start from poor voltage estimates. Cannot handle network with low X/R ratio branch-	Poor voltage estimate and network contains negative reactive branch.	Network contains branches with low X/R ratios. Overloading has produced reactive power problems.	As for FNSL.	As for FNSL.

Activity/ Iteration Method	Advantages	Disadvantages	Use When	Do Not Use When	Convergence Monitor	Interrupt Options
		es (e.g., equivalents). No indication of cause of problem when failing to converge. Can give problems converging cases where reactive power limits are restrictive.				
FDNS Newton-Raphson method with real and reactive power equations decoupled using a fixed Jacobian matrix	Rapid convergence on well-conditioned cases. Small bus mismatches can be achieved.	As mismatches are reduced, rate of improvement may be allowed. Intolerant of data errors. No indication of cause of problem when failing to converge. Can give problems converging cases where reactive power limits are restrictive.		Overloading has produced reactive power problems.	As for FNSL.	As for SOLV.

Experimentation is needed to determine the optimum combination of iterative methods for each particular power system model.

Experience suggests the following as the most advantageous approach to new power flow cases where the specific characteristics have yet to be learned:

- Initialize all voltages to either unity amplitude, or to scheduled amplitude if given, and initialize all phase angles to zero. (This step is referred to as a flat start.)

- Run Gauss-Seidel iterations until the adjustments to the voltage estimates decrease to, say, 0.01 or 0.005 per unit in both real and imaginary parts.
- Switch to Newton-Raphson iterations until either the problem is converged, or the reactive power output estimates for generators show signs of failure to converge.
- Switch back to Gauss-Seidel iterations if the Newton-Raphson method does not settle down to a smooth convergence within 8 to 10 iterations.

Experience with each specific problem will suggest modifications to this procedure. In particular, the initial Gauss-Seidel iterations and flat-start steps will be bypassed when the result of a previous solution is known to be a close estimate of the expected new solution.

5.8.2. Switching and Dynamic Simulation

While the five iterative schemes listed in Table 5.2, "Power Flow Solution Activities—Selection Guide"could be used for switching and dynamic simulation network solutions, they are not well suited to the generator dynamic boundary conditions shown in Figure 5.8, "Generator-Network Coupling Models for Power Flow, Switching, and Dynamic Simulation Calculations"c. PSS®E includes a special iterative solution activity, TYSL, for use in switching and dynamic simulations. This particular iteration method handles the network part of the problem by direct solution and, accordingly, has convergence characteristics that are largely insensitive to network impedances. The convergence of the TYSL iteration is sensitive to the form of the load boundary conditions. It will fail occasionally if faults or severe overloads draw bus voltages down into the ranges shown in Figure 5.8, "Generator-Network Coupling Models for Power Flow, Switching, and Dynamic Simulation Calculations" and Figure 5.4, "Constant Current Load Characteristic and Resultant Form of Load MVA/ Voltage Curve" where the load characteristics are switched over to the arbitrary elliptical curve to ensure zero current at zero voltage. Because the load characteristics are an arbitrary choice at these low voltages, it is usually permissible to adjust the load model at offending buses. The simplest way of obtaining convergence in very low-voltage situations is to increase the fraction of total bus load that is represented as constant admittance. (This can be implemented rapidly by the *Convert / Reconstruct loads* function from the dialog that opens when selecting *Power Flow>Convert Loads and Generators...*. The TYSL solution is always completed in one iteration if the total load is assigned constant admittance characteristic and no DC transmission lines or FACTS devices are being modeled. Convergence can usually be obtained, even in faulted conditions, by representing load as constant admittance only in areas near the fault. However, the TYSL solution cannot be used for t^- network solutions.

5.8.3. Multiple Power Flow Solutions and Voltage Collapse

Introduction

It can be quite disconcerting when two solution techniques calculate different power flows for the same system, or worse yet, the same solution technique calculates different power flows when started from different initial conditions.

- Is something wrong with the solution algorithm?
- Which solution is correct?
- Do both solutions represent possible operating conditions?

Actually, it is surprising that multiple power flow solutions are not encountered more often. The power flow constraints are, after all, not linear and, as the quadratic equation demonstrates, nonlinear equations have multiple solutions. In fact, for a large system with many machine constraints, many possible solutions might be expected.

Multiple Solutions with Synchronous Load

The familiar power angle characteristic, Figure 5.9, "Power Angle Characteristic", illustrates one family of multiple solutions. The power which can be transmitted through a reactance, *X*, is given by

$$P = \frac{V_S V_R}{X} \sin(\theta_{SR})$$

where

V_S and $\angle \theta_S$ are the sending-end voltage magnitude and angle.

V_R and $\angle \theta_R$ are the receiving-end voltage magnitude and angle.

$\theta_{SR} = \theta_S - \theta_R$ is the phase angle difference between the sending and receiving ends.

The load characteristic is a horizontal straight line for constant power load. The intersection points of the power transmission characteristic and load characteristic indicate the possible network solutions because both the transmission and load constraints are satisfied. Two angles, (θ_{SR}), satisfy both the power transmission characteristic and the load constraint.

Assuming that the angles θ_S and θ_R are related to the rotor angles of synchronous machines in the sending and receiving system, the following analysis applies. If a deficit of electric power exists in the receiving system, the machines in that system will slow down and the angle ($\theta_S - \theta_R$) will increase. For operating point A, on the power angle characteristic, the increase in angle will result in an increase in electrical power until load is satisfied and a new steady-state operating point is reached. For operating point B, the increase in angle will result in less electrical power, which will further decelerate the receiving end so no steady-state operating point will be found. One solution, then, corresponds to a stable steady-state operating condition and the other to an unstable condition.

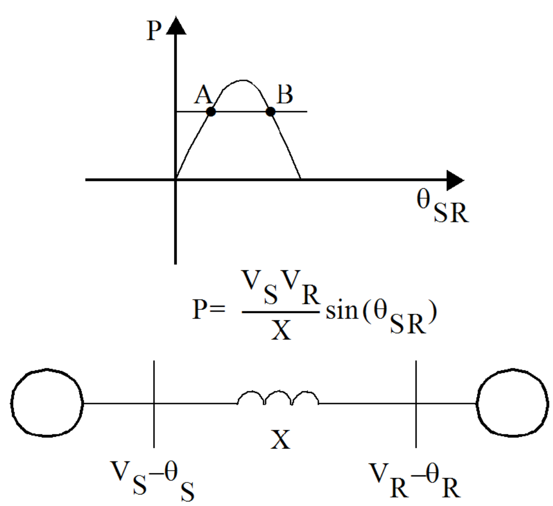


Figure 5.9. Power Angle Characteristic

Multiple Solutions with Self-Restoring Asynchronous Load

Figure 5.10, "Two-Bus System With Static Load" shows a simple two-bus system that illustrates another type of multiple solution to the power flow problem. However, this solution is less understood than that shown in Figure 5.9, "Power Angle Characteristic". Here it is assumed that there are no important synchronous machines in the receiving system, and, therefore, the electrical angle of the receiving system cannot be related to a rotor angle in the receiving system.

If the receiving-end current is 90° out of phase with the receiving-end voltage, i.e., purely reactive load, then the current versus voltage characteristic is given by a straight line (Figure 5.11, "Voltage versus Reactive Current Transmission Characteristic"). If the receiving-end current is in phase with the voltage, then the current versus voltage characteristic is given by an ellipse (Figure 5.12, "Voltage versus Active Current Transmission Characteristic").

The current delivery characteristics for other power factors lie between the ellipse and straight line. Again, multiple solutions can be shown by a graphical analysis. The load characteristic may be superimposed onto the voltage versus current characteristic. For constant power load, $P = VI$, the load characteristic is a hyperbole (Figure 5.13, "Voltage versus Current Transmission Characteristics and Loci of Constant Active Load").

Each intersection of the current delivery characteristic and the load characteristic represents a solution to the power flow equations. As Figure 5.13, "Voltage versus Current Transmission Characteristics and Loci of Constant Active Load" indicates, there are two possible solutions for a given level of power. Again the question can be asked: Do both solutions relate to possible operating points for the actual system?

To answer this question, it is necessary to consider how constant power load is achieved in the real system. Most load does not draw constant real and reactive power during or immediately following a change in system voltage, but many types of load will, over a period of time, change electrically while attempting to draw essentially constant power. Resistive heating load, for example, will vary with the square of voltage immediately following a disturbance. However, if voltage is depressed for some time, thermostats will cycle each element of resistive heating more often, and people will use appliances longer to perform the same task. Note that as more of this type of load is connected, the admittance of the combined load increases over a period of time until the customer's power requirements are satisfied.

Load behind a load tap changer (LTC) will also tend to self-restore, over a period of time, following a disturbance. LTCs change taps to raise the voltage at the load and restore the power and var requirements to their original level. At the same time, the admittance of load, as seen from the transmission side of the LTCs, will increase by the square of the turn ratio. Thus, if the voltage and power delivered to the load is low, the LTCs effectively increase the admittance of the load, as seen from the transmission system. This increase may result in some voltage drop on the primary side, which is normally more than offset by the change in turn ratio so that the secondary voltage increases until the original level of secondary voltage and load is obtained.

Similarly, if the electrical power received by an induction motor is not sufficient to satisfy its mechanical load, the slip will increase. An increase in slip, S, increases the admittance of the motor, as shown in Figure 5.14, "Induction Motor Equivalent Circuit". So induction motors also respond to a deficit in electrical power by raising the level of admittance perceived by the system. Normally this response has the effect of raising the electrical power received by the motor until its power demands are satisfied.

In the problem of the double power flow solution, each solution corresponds to a different load admittance. The two solutions really correspond to two physically different loads, which both happen to draw the same level of power when supplied by a practical power system.

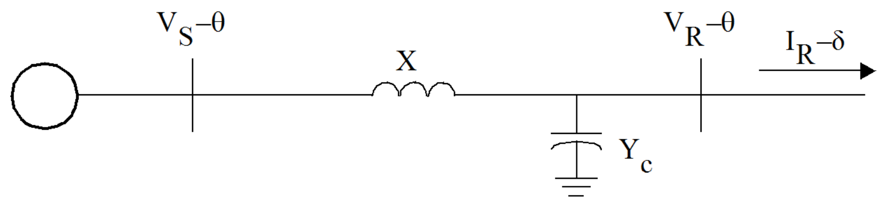


Figure 5.10. Two-Bus System With Static Load

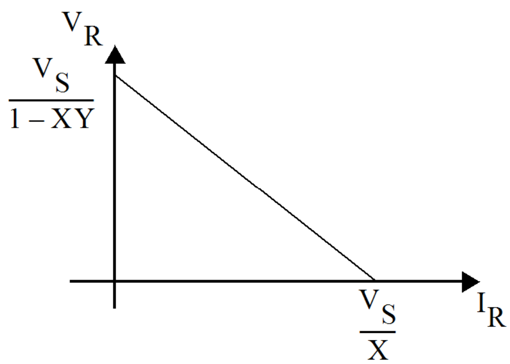


Figure 5.11. Voltage versus Reactive Current Transmission Characteristic

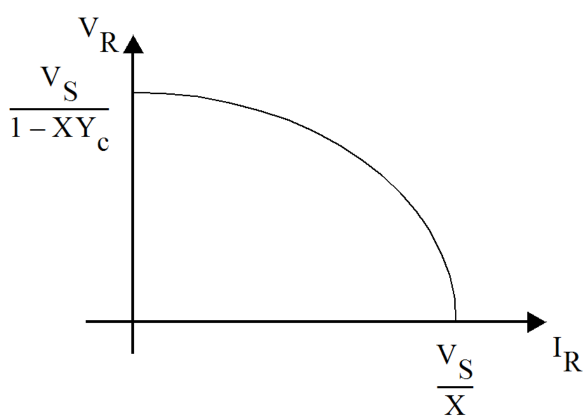


Figure 5.12. Voltage versus Active Current Transmission Characteristic

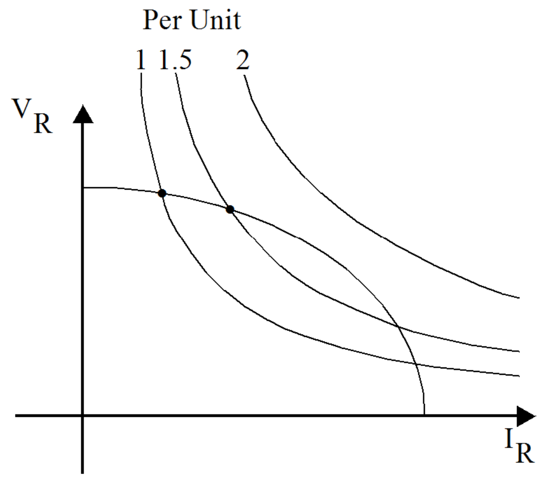


Figure 5.13. Voltage versus Current Transmission Characteristics and Loci of Constant Active Load

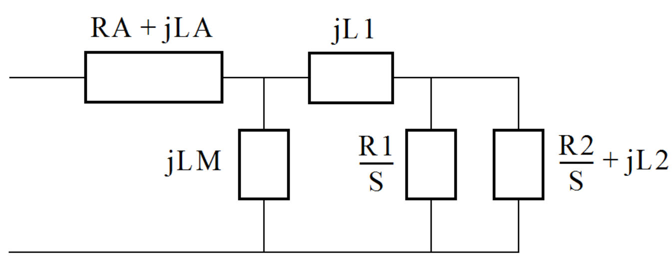


Figure 5.14. Induction Motor Equivalent Circuit

As the load is restored following a voltage drop, the level of admittance will increase. For solution A in Figure 5.15, “Change in Operating Point for a Change in Load Admittance”, increasing the admittance will increase the power delivery and the load will be satisfied. For the second solution, B, the power delivery will drop as the admittance increases. Thermostats, LTCs and other automatic load adjustment equipment will, therefore, further increase the load admittance perceived by the system in an attempt to achieve their control objective. Eventually, either voltage will collapse or the load controls will run out of range and the constant power characteristic will not be satisfied. Hence, the second solution, B, does not correspond to a stable operating point for this situation.

Multiple Solutions with Fast Controllable Shunt Compensation

One other possible mechanism for restoring the power delivery following a voltage drop exists. Shunt reactive compensation could be switched to raise the receiving-end voltage by using static var compensators (SVCs) or by using voltage-controlled mechanically switched reactors and capacitors. The addition of shunt compensation changes the current delivery characteristic, as shown in Figure 5.16, “Change in Operating Point for Both Solutions when Shunt Compensation is Switched”.

As the figure illustrates, assuming constant admittance loads, both solutions will yield increased power delivery as shunt compensation is added to correct voltage. Thus, a continuous voltage-controlled var source, such as an SVC or synchronous condenser, will restore the power delivery to the desired level for both operating points and even operating point, B, will be stable. This is true as long as the control response of the var source is faster than the process of load admittance change, which is also attempting to restore constant power, a process that develops over minutes. However, if the SVC reaches the end of its range and the system is at an unstable operating point such as B, the voltage would run away in one direction or another.

Identifying Extraneous Solutions

All commonly used power flow solution algorithms have a strong preference for converging to the normal operating point where power delivery increases with load admittance. Some algorithms, including Newton Raphson, will, however, converge to an abnormal solution depending on the starting voltages. Several examples [1] exist showing power flows converging to more than one solution. User tricks have been designed to aid convergences. The use of make-believe synchronous condensers to hold voltage at sensitive buses, improperly combine var load with shunt compensation, and convert to constant impedance load may encourage or force convergence to an abnormal solution. Conversely, practices such as netting generation with load may change the character of the system so that it is hard to converge to what would be a normal operating point if the generator were explicitly represented.

In a complex system power flow convergence to an alternate solution may not be obvious. Sometimes ridiculous flows and voltages will indicate an alternate solution. However, as seen in Figure 5.16, “Change in Operating Point for Both Solutions when Shunt Compensation is Switched”, when the system is heavily loaded, two solutions may be close together and, therefore, have equally reasonable (unreasonable?) flows and voltages. Is there a simple way to test for convergence to an abnormal solution?

One way of testing involves the following steps: 1) convert the solved case load, including any make-believe synchronous condensers to constant admittance; 2) increment the load admittance slightly and resolve; and 3) check to see if the new admittance draws more or less MVA than the original. If an increase in admittance results in a decrease in MVA, then the system has converged to the abnormal operating point. This test will only work, of course, if system load is represented explicitly and is not included with generation conditions or equivalence circuit data.

[1] "Extraneous and False Power Flow Solutions," B.K. Johnson, IEEE Transactions paper, presented at the 1976 Summer Power Meeting.

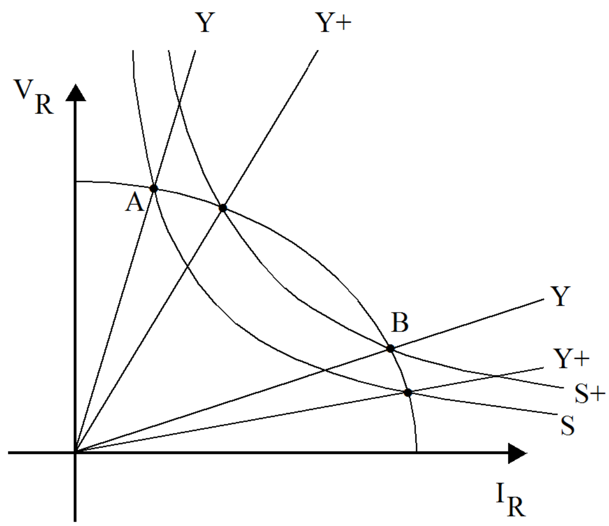


Figure 5.15. Change in Operating Point for a Change in Load Admittance

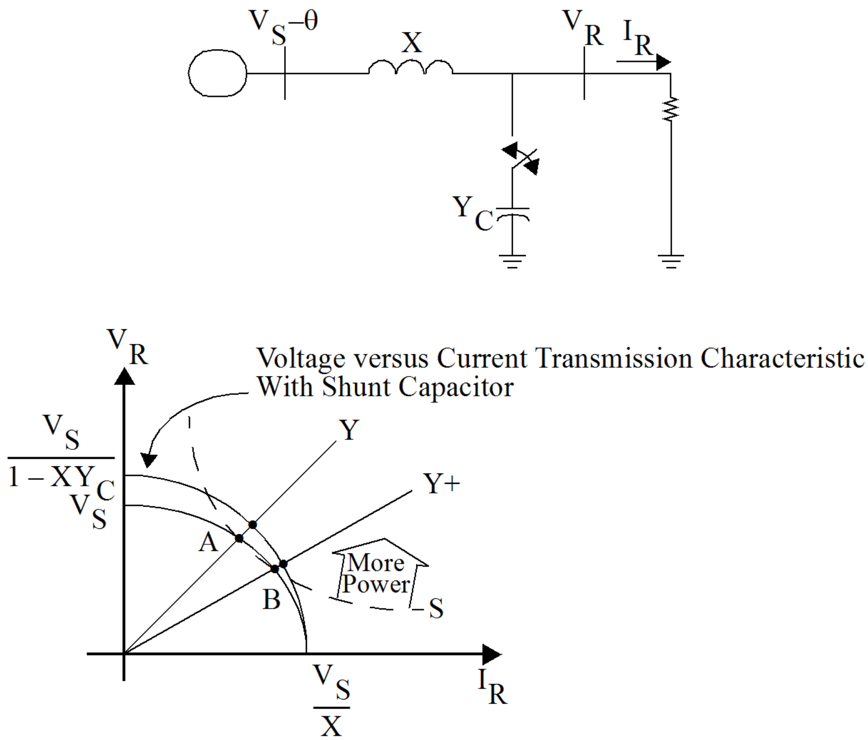


Figure 5.16. Change in Operating Point for Both Solutions when Shunt Compensation is Switched

Chapter 6

Basic Power Flow Activity Applications

6.1. Construction and Changes

PSS®E makes a clear distinction between the construction of a power system model and the changing of model data. The addition of any bus, transmission line, transformer, or generator to the system model is construction. Changing of the status of any component or the value of any parameter is a model change. Functions that can contribute to model construction and most often will get their input from files found in the following menus:

Powerflow Selector File>Open...	Add buses, lines, transformers, or generators.
Powerflow Selector File>Open...	Append negative- and zero-sequence data to an existing positive-sequence model.
Dynamic Selector File>Input	Append dynamic simulation data to an existing positive-sequence model.
Powerflow Selector File>Open...	Add generating units to an existing plant.

The activities found in these menus can add new elements to an existing system model as well as redefine the parameters of existing elements. A completely new model is constructed by commencing execution of *Read powerflow input data* with an empty working file. The basic topology of all system models is defined by the positive-sequence network model as constructed by this activity. Components can be added to the negative-/zero-sequence and dynamics sections of the system model only after they have been added to the positive-sequence model.

Any parameter of any component in the system model can be changed in value after the construction of the component has been recorded by entries in the working case. PSS®E has several activities that can change equipment parameters. These functions are found within the data spreadsheets.

6.2. Data Checking

6.2.1. General Points

Activities LIST and EXAM are of great value in the review and verification of system data when an area of suspect data has been found. They are most valuable when used in conjunction with the diagnostic activities BRCH, TPCH, TREE, and CNTB, which are initiated by selecting *Power Flow>Check Data*.

Location of problems in power system power flow data is helped by a recognition of types of error most often found in large-scale power flow data setups. Sample errors follow:

- Misplaced decimal points that increase or decrease loads, impedances, etc., by factors of 10.
- Omission of data records for buses, branches, or generators.
- Components left in or out of service in adapting a model from one condition (load level, year, etc.) to another.

Visual examination of full system data listings is not an effective way of finding such data errors. The correct approach is to subject the system model to tests designed to detect inconsistencies and exceptional conditions, and to use these to focus attention on limited sections of the full data listing.

6.2.2. Activity OUTS

Activity OUTS, run by selecting *Power Flow>List Data...* (*Outaged equipment*), prints a summary of out-of-service branches, isolated buses, disconnected generating plants, disconnected machines at in-service plants, and blocked (out-of-service) dc lines. Primarily OUTS assists in reviewing the system condition represented by a power flow saved case that has just been returned to working memory by activity CASE. It can also be used to ensure that a sequence of equipment status changes has been applied correctly.

```
     PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS®E      WED, DEC 08 1999  15:29
SAMPLE SYSTEM FOR PSS®E MANUAL                                   SYSTEM SUMMARY
1100KV DC CASE

------------------BUSES-----------------         GENERATION AREAS ZONES OWNERS AREA
TOTAL PQ<>0. PQ=0. PE/E  PE/Q SWING OTHER  LOADS PLANTS MACHS USED  USED  USED TRANS
  18      7     5     4     0     2     0      7      6     9     4     2     1     0
------------------AC BRANCHES------------------ 3WND MULTI-SECTION   DC LINES FACTS
 TOTAL    RXB    RX   RXT   RX=0.    IN    OUT XFRM  LINES SECTNS 2-TRM N-TRM DEVS
    34     26     2     6     0      34      0    0      0      0     2     0    0

TOTAL GENERATION PQLOAD   I LOAD   Y LOAD   SHUNTS  CHARGING  LOSSES    SWING
MW      6737.3  6500.0      0.0      0.0      0.0      0.0    126.0   4237.3
MVAR    2279.1     0.0      0.0      0.0   -408.1   1062.2   1732.1    710.8

TOTAL MISMATCH = 6238.41 MVA X-----AT BUS-----X    SYSTEM   X------SWING-----X
 MAX. MISMATCH = 3114.16 MVA  1600 MINE     765       BASE     200 HYDRO     345
  HIGH VOLTAGE = 1.06099 PU   1100 CATNIP   230      100.0    1600 MINE      765
  LOW  VOLTAGE = 0.97780 PU   1300 SERGA    230 ADJTHR ACCTAP TAPLIM   THRSHZ
                                                0.0050 1.0000 0.0500  0.000100
X-------SOLV AND MSLV-------X   X---NEWTON---X  X------TYSL------X BLOW  PQ
 ACCP  ACCQ  ACCM    TOL  ITER   ACCN  TOL ITER  ACCTY    TOL  ITER  UP  BRAK
1.600 1.600 1.000 0.00010 100   1.00 0.100  20   1.000 0.000010  20  5.0 0.70

     PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS®E      WED, DEC 08 1999  15:29
SAMPLE SYSTEM FOR PSS®E MANUAL                                          WORST
1100KV DC CASE                                                     MISMATCHES
 BUS#   NAME   BSKV       MW        MVAR       MVA
 1600 MINE      765   3000.00     835.44   3114.16
 1403 WDUM     18.0  -1444.36     591.02   1560.60
 1404 EDUM     18.0  -1444.36     591.02   1560.60
 1201 SWIGA     230     -0.12       1.16      1.17
 1200 STERML    230      0.16      -1.10      1.11
 1401 WCOND    18.0      0.00      -0.10      0.10
 1402 ECOND    18.0      0.00      -0.10      0.10
  100 NUCLEAR   345     -0.03      -0.09      0.10
 1550 MIDPNTL   345      0.02       0.08      0.09
  600 EASTLV    230      0.05      -0.06      0.08
  400 EAST      345     -0.02       0.07      0.07
  700 SWURB     230     -0.03       0.06      0.06
  800 SETOUN    230     -0.03      -0.05      0.06
  300 WEST      345     -0.01      -0.04      0.04
 1100 CATNIP    230      0.01       0.02      0.03
 1300 SERGA     230      0.00      -0.02      0.02
  500 WESTLV    230      0.01      -0.01      0.01
  200 HYDRO     345      0.01      -0.01      0.01

    PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS®E      WED, DEC 08 1999  15:29
SAMPLE SYSTEM FOR PSS®E MANUAL                                       BUS DATA
1100KV DC CASE
 BUS#   NAME    BSKV  CODE LOADS  VOLT   ANGLE       S H U N T   AREA ZONE OWNER
  100 NUCLEAR 345.00   2     0  1.0400   -2.1     0.0      0.0     1    1    1
  200 HYDRO   345.00   3     0  1.0400    0.0     0.0      0.0     1    1    1
  300 WEST    345.00   1     0  0.9997  -22.7     0.0      0.0     1    1    1
  400 EAST    345.00   1     0  1.0041  -22.5     0.0      0.0     1    1    1
  500 WESTLV  230.00   1     1  0.9955  -26.1     0.0      0.0     2    1    1
  600 EASTLV  230.00   1     1  1.0048  -24.9     0.0      0.0     2    1    1
  700 SWURB   230.00   1     1  0.9910  -26.5     0.0      0.0     2    1    1
  800 SETOUN  230.00   1     1  1.0185  -25.3     0.0      0.0     2    1    1
 1100 CATNIP  230.00   2     0  1.0610  -21.3     0.0      0.0     2    1    1
 1200 STERML  230.00   1     0  0.9949  -14.0     0.0      0.0     3    2    1
 1201 SWIGA   230.00   1     1  0.9941  -14.9     0.0    200.0     3    2    1
 1300 SERGA   230.00   1     1  0.9778  -26.8     0.0      0.0     3    2    1
 1401 WCOND   18.000   2     0  1.0259   -7.2     0.0    100.0     3    2    1
 1402 ECOND   18.000   2     0  1.0259   -7.2     0.0    100.0     3    2    1
 1403 WDUM    18.000   1     0  1.0000   -7.2     0.0      0.0     3    2    1
 1404 EDUM    18.000   1     0  1.0000   -7.2     0.0      0.0     3    2    1
 1550 MIDPNTL 345.00   1     1  1.0285   -6.7     0.0      0.0     4    2    1
 1600 MINE    765.00   3     0  1.0400    0.0     0.0      0.0     4    2    1
```

Figure 6.1. Activity LIST Report (Sheet 1 of 5)

Figure 6.2. Activity LIST Report (Sheet 2 of 5)

Figure 6.3. Activity LIST Report (Sheet 3 of 5)

Figure 6.4. Activity LIST Report (Sheet 4 of 5)

```
     PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS®E      WED, DEC 08 1999  15:29
SAMPLE SYSTEM FOR PSS®E MANUAL                                     DC LINE DATA
1100KV DC CASE
DC# MDC   RDC     RCOMP    DELTI SETVAL VSCHED DCVMIN VCMODE DCAMPS   VCOMP METER
  1  1   8.200   0.000   0.1500 1500.0  554.4     0.0  443.5     0.0     0.0  INV

   X---CONVERTER BUS--X  ALF/GAM     MIN      MAX      PAC      QAC      VDC
R:  1600 [MINE      765]   90.00    5.00   40.00      0.0      0.0      0.0
I:  1403 [WDUM     18.0]   90.00   18.00   30.00      0.0      0.0      0.0

   NB  EBASE RC-OHMS XC-OHMS XCCC-OHMS  TR      TAP    TAPMIN  TAPMAX  TAPSTP
R:  2  500.0  0.000   3.880    0.000  0.44000 1.03125 0.90000 1.10000 0.00625
I:  2  230.0  0.000   3.047    0.000  0.96500 1.00000 0.90000 1.10000 0.00625

   X---MEASURING BUS--X  X- WINDING 1 SIDE -X X- WINDING 2 SIDE -X CKT  RATIO
R:      0 [             ]
I:      0 [             ]

DC# MDC   RDC     RCOMP    DELTI SETVAL VSCHED DCVMIN VCMODE DCAMPS   VCOMP METER
  2  1   8.200   0.000   0.1500 1500.0  554.4     0.0  443.5     0.0     0.0  INV

   X---CONVERTER BUS--X  ALF/GAM     MIN      MAX      PAC      QAC      VDC
R:  1600 [MINE      765]   90.00    5.00   40.00      0.0      0.0      0.0
I:  1404 [EDUM     18.0]   90.00   18.00   30.00      0.0      0.0      0.0

   NB  EBASE RC-OHMS XC-OHMS XCCC-OHMS  TR      TAP    TAPMIN  TAPMAX  TAPSTP
R:  2  500.0  0.000   3.880    0.000  0.44000 1.03125 0.90000 1.10000 0.00625
I:  2  230.0  0.000   3.047    0.000  0.96500 1.00000 0.90000 1.10000 0.00625

   X---MEASURING BUS--X  X- WINDING 1 SIDE -X X- WINDING 2 SIDE -X CKT  RATIO
R:      0 [             ]
I:      0 [             ]

     PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS®E      WED, DEC 08 1999  15:29
SAMPLE SYSTEM FOR PSS®E MANUAL                                        AREA DATA
1100KV DC CASE
X-- AREA --X X-------------- AREA SWING --------------X X--- DESIRED ---X
              BUS#   NAME  BSKV    PGEN     PMAX     PMIN INTERCHANGE TOLER BUSES      LOADS  DC BUSES
  1 GENSYS     200 HYDRO    345  1237.3  1750.0      0.0       0.0   9999.0     4          0         0
  2 LOADSYS   1100 CATNIP   230   500.0   500.0    150.0  -2600.0      15.0     5          4         0
  3 NEWLOAD      0                                             0.0   9999.0     7          2         0
  4 REMGEN       0                                             0.0   9999.0     2          1         0
                                          SUMMATION:      -2600.0

     PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS®E      WED, DEC 08 1999  15:29
SAMPLE SYSTEM FOR PSS®E MANUAL                                       INTER-AREA
1100KV DC CASE                                                    TRANSFER DATA
X--FROM AREA-X X---TO AREA--X ID  PTRANS  PTOTAL  DESINT

                                   * NONE *

     PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS®E      WED, DEC 08 1999  15:29
SAMPLE SYSTEM FOR PSS®E MANUAL                                        ZONE DATA
1100KV DC CASE
X-- ZONE --X BUSES     LOADS  DC BUSES
  1              9         4         0
  2              9         3         0

     PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS®E      WED, DEC 08 1999  15:29
SAMPLE SYSTEM FOR PSS®E MANUAL                                       OWNER DATA
1100KV DC CASE
X-- OWNER -X BUSES     LOADS  MACHINES  BRANCHES  DC BUSES  FACTS DEVS
  1             18         7         9        34         0         0

     PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS®E      WED, DEC 08 1999  15:29
SAMPLE SYSTEM FOR PSS®E MANUAL                                    FACTS CONTROL
1100KV DC CASE                                                      DEVICE DATA
FD# X- SENDING BUS --X X- TERMINAL BUS -X MODE  PDES   QDES  V SET SHNTMX BRDGMX  VTMAX  VTMIN VSRMAX ISRMAX
LINE X OWNER

                                   * NONE *
```

Figure 6.5. Activity LIST Report (Sheet 5 of 5)

Figure 6.6. Single-Screen Display of All Data Pertaining to Bus 300 From Activity RATE

A bus is listed by OUTS as being *isolated* if it has no in-service ac branch connected to it. If the type code of the isolated bus is not 4, its bus number is preceded by an asterisk. The asterisk is a warning that either the type code should be changed to 4, or a branch to the bus should be returned to service. (An exception to this rule is the bus representing an isolated plant feeding only dc transmission, such as bus 1600 in Figure 6.14, "One-Line Diagram of Sample System", which should have a type code of 3.)

Figure 6.7, "Report from Activity OUTS dc Circuit #1 and ac Branches of Inverter Transformer Out-of-Service but Type Code of Bus 1403 not Changed to 4 as Required" shows a report from OUTS, as requested, to confirm correct execution of the sequence of changes needed to take dc line Number 1 out of service. The asterisk alongside bus 1403 indicates that its type code has not been changed to 4 as required.

Note that the asterisk beside bus 1600 does not indicate an error because this bus represents an isolated plant feeding the remaining dc transmission line.

6.2.3. Activity TREE

Activity TREE checks the topological connectivity of the network by building trees outward from each Type 3 bus. TREE finds the first Type 3 bus and works outward through the tree of all in-service branches connected to it. On reaching the end of the tree, the activity locates the next Type 3 bus that is not yet in a tree and repeats the process. When no more buses can be incorporated in a tree from a Type 3 bus, TREE lists the number and name of all swing buses and the number and name of all buses that cannot be reached from a swing bus via in-service branches. The latter are either isolated with no branches connected to them, or they are part of an isolated island of buses and branches that does not contain a swing bus.

Activity TREE does not necessarily detect system separations. It will detect isolated buses only if there is no swing bus in the island. A separated system with a swing bus in each section is considered by TREE to be a normal occurrence. When TREE notes that the system has a group of buses in an island, it indicates one of the following:

- One or more branches was omitted from the branch data in the raw data file.
- A from or to bus number was incorrect in a branch data record.
- All branches were included in the raw data file but one or more was skipped by activity READ because data on a bus was omitted from the bus data section of the raw data file.
- A branch, or branches, was neglected in changing the system from one operating condition to another when equipment was being returned to service.

Upon detecting and reporting an isolated bus or island, Activity TREE offers to disconnect it. If invoked by the user, this function of TREE changes the type code of each listed bus to 4 and the status of all branches in the island to zero (out of service). The alternative to removing isolated and islanded buses from service is to change the type code of one such bus in each island to 3, re-run activity TREE to see if any unenergized islands remain, and, if so, change another bus to Type 3 until all buses are connected to at least one Type 3 bus.

```
     PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS®E      WED, DEC 08 1999  15:47
SAMPLE SYSTEM FOR PSS®E MANUAL
1100KV DC CASE

OUT OF SERVICE BRANCHES:

X--- FROM BUS ---X AREA     X---- TO BUS ----X AREA    CKT
 1200 STERML   230    3      1403 WDUM     18.0    3     1
 1401 WCOND   18.0    3      1403 WDUM     18.0    3     1


OUT OF SERVICE THREE-WINDING TRANSFORMERS:

  NAME   X--WINDING 1 BUS-X AREA  X--WINDING 2 BUS-X AREA  X--WINDING 3 BUS-X AREA
CKT
                                   ** NONE **


ISOLATED BUSES:

X------ BUS -----X  AREA   X------ BUS -----X  AREA   X------ BUS -----X  AREA
 1401 WCOND   18.0 *   3    1403 WDUM    18.0 *   3    1600 MINE      765 *   4

OUT OF SERVICE PLANTS:

X------ BUS -----X  AREA   X------ BUS -----X  AREA   X------ BUS -----X  AREA

                                   ** NONE **

OUT OF SERVICE MACHINES AT IN SERVICE PLANTS:

X------ BUS -----X # AREA  X------ BUS -----X # AREA  X------ BUS -----X # AREA

                                   ** NONE **


OUT OF SERVICE LOADS AT IN SERVICE BUSES:

X------ BUS -----X # AREA  X------ BUS -----X # AREA  X------ BUS -----X # AREA

                                  ** NONE **


BLOCKED TWO-TERMINAL DC LINES:

DC# X--- RECTIFIER --X  X--- INVERTER ---X
  1  1600 MINE     765   1403 WDUM    18.0


BLOCKED MULTI-TERMINAL DC LINES:

DC# X--- CONVERTER --X X--- CONVERTER --X X--- CONVERTER --X X--- CONVERTER --X

                                  ** NONE **


BLOCKED FACTS CONTROL DEVICES:

FD# X-- SENDING BUS -X  X- TERMINAL BUS -X

                                  ** NONE **
```

Bus 1403 is isolated but
Not Type 4, warning

Bus 1600 is isolated and not Type 4
OK, it's a plant connected to dc
transmission only and is Type 3

Figure 6.7. Report from Activity OUTS dc Circuit #1 and ac Branches of Inverter Transformer Out-of-Service but Type Code of Bus 1403 not Changed to 4 as Required

6.2.4. Topology Checking

Figure 6.8, “Sample Application of OUTS and TREE (Sheet 1 of 2)” shows OUTS and TREE reports used to detect and rectify an error resulting from a sequence of data changes.

Activity OUTS verifies that the two status changes were made correctly. The OUTS report shows both elements to be out of service as required and shows, furthermore, that no other system elements are out of service.

Activity OUTS is followed immediately by TREE to check for islanded subsystems. TREE reports first that both bus 200 and bus 1600 are swing buses, which is correct because bus 1600 is connected only to the dc transmission: TREE then reports that buses 1401 and 1403 are unable to be reached from either swing bus. Because they do not appear in the OUTS report, these buses must have at least one branch connected to them, making them an isolated island. A check on the system diagram, Figure 6.14, “One-Line Diagram of Sample System”, shows that these two buses represent the tertiary winding and synchronous condensers of the out-of-service inverter unit; branch 1401-1403 should be out of service and the bus type code should be changed to 4. TREE is instructed to make this change. OUTS and TREE are then run again. The second OUTS report confirms that the previous action by TREE did isolate buses 1401 and 1403 with a type code equal to 4. The second TREE report shows that the system model is ready for solution.

```
    PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS/E      WED, DEC 08 1999   16:35
SAMPLE SYSTEM FOR PSS/E MANUAL
1100KV DC CASE

OUT OF SERVICE BRANCHES:

X--- FROM BUS ---X AREA     X---- TO BUS ----X AREA   CKT
 1200 STERML   230    3      1403 WDUM    18.0    3    1

OUT OF SERVICE THREE-WINDING TRANSFORMERS:

  NAME   X--WINDING 1 BUS-X AREA  X--WINDING 2 BUS-X AREA  X--WINDING 3 BUS-X AREA  CKT
                                  ** NONE **

ISOLATED BUSES:

X------ BUS -----X  AREA   X------ BUS -----X  AREA   X------ BUS -----X  AREA
 1600 MINE      765 *    4

OUT OF SERVICE PLANTS:

X------ BUS -----X  AREA   X------ BUS -----X  AREA   X------ BUS -----X  AREA
                                  ** NONE **

OUT OF SERVICE MACHINES AT IN SERVICE PLANTS:

X------ BUS -----X # AREA  X------ BUS -----X # AREA  X------ BUS -----X # AREA
                                  ** NONE **

OUT OF SERVICE LOADS AT IN SERVICE BUSES:

X------ BUS -----X # AREA  X------ BUS -----X # AREA  X------ BUS -----X # AREA
                                  ** NONE **
```

Seems OK; the dc line is blocked and transformer is out-of-service

```
BLOCKED TWO-TERMINAL DC LINES:

DC# X--- RECTIFIER --X  X--- INVERTER ---X
  1  1600 MINE      765   1403 WDUM     18.0

BLOCKED MULTI-TERMINAL DC LINES:

DC# X--- CONVERTER --X X--- CONVERTER --X X--- CONVERTER --X X--- CONVERTER --X
                                  ** NONE **

BLOCKED FACTS CONTROL DEVICES:

FD# X-- SENDING BUS -X  X- TERMINAL BUS -X
                                  ** NONE **

Executing activity TREE
```

Last check with activity TREE

```
                                 SWING BUSES

X-------BUS------X AREA    X-------BUS------X AREA    X-------BUS------X AREA
  200 HYDRO     345     1    1600 MINE      765     4
```

That's OK; 1600 is on the dc system only

```
                                   ISLAND

X-------BUS------X AREA    X-------BUS------X AREA    X-------BUS------X AREA
 1401 WCOND    18.0     3    1403 WDUM    18.0     3

ISLAND CONTAINS     2 BUSES AND   1 PLANTS WITH TOTALS OF:

    PLOAD      QLOAD        I - L O A D          Y - L O A D          S H U N T
      0.0        0.0        0.0        0.0       0.0        0.0       0.0      100.0

     PGEN       QGEN       QMAX       QMIN
      0.0      653.5      800.0     -100.0
```

OH-OH! These were not shown by OUTS; they are an island. A check with Figure 6-32 shows they are converter transformer star-point and tertiary buses

Figure 6.8. Sample Application of OUTS and TREE (Sheet 1 of 2)

```
     PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS/E      WED, DEC 08 1999   16:40
SAMPLE SYSTEM FOR PSS/E MANUAL
1100KV DC CASE

OUT OF SERVICE BRANCHES:

X--- FROM BUS ---X AREA     X---- TO BUS ----X AREA    CKT
 1200 STERML    230    3      1403 WDUM     18.0    3    1
 1401 WCOND    18.0    3      1403 WDUM     18.0    3    1

OUT OF SERVICE THREE-WINDING TRANSFORMERS:

  NAME   X--WINDING 1 BUS-X AREA  X--WINDING 2 BUS-X AREA  X--WINDING 3 BUS-X AREA  CKT

                                  ** NONE **

ISOLATED BUSES:

X------ BUS -----X  AREA   X------ BUS -----X  AREA   X------ BUS -----X  AREA
 1401 WCOND    18.0     3    1403 WDUM     18.0     3    1600 MINE      765 *   4

OUT OF SERVICE PLANTS:

X------ BUS -----X  AREA   X------ BUS -----X  AREA   X------ BUS -----X  AREA
 1401 WCOND    18.0     3

OUT OF SERVICE MACHINES AT IN SERVICE PLANTS:

X------ BUS -----X # AREA  X------ BUS -----X # AREA  X------ BUS -----X # AREA

                                  ** NONE **

OUT OF SERVICE LOADS AT IN SERVICE BUSES:

X------ BUS -----X # AREA  X------ BUS -----X # AREA  X------ BUS -----X # AREA

                                  ** NONE **

BLOCKED TWO-TERMINAL DC LINES:

DC# X--- RECTIFIER --X  X--- INVERTER ---X
  1  1600 MINE      765   1403 WDUM     18.0

BLOCKED MULTI-TERMINAL DC LINES:

DC# X--- CONVERTER --X X--- CONVERTER --X X--- CONVERTER --X X--- CONVERTER --X

                                  ** NONE **

BLOCKED FACTS CONTROL DEVICES:

FD# X-- SENDING BUS -X  X- TERMINAL BUS -X

                                  ** NONE **

Executing activity TREE


                                  SWING BUSES

X-------BUS------X AREA    X-------BUS------X AREA    X-------BUS------X AREA
  200 HYDRO     345    1     1600 MINE      765    4

                                    ISLAND

X-------BUS------X AREA    X-------BUS------X AREA    X-------BUS------X AREA

                                  ** NONE **
```

OK; tertiary branches and buses are now out-of-service as required

Synchronous condenser is off too

Last check with TREE

That's OK

No unwanted islands; we're ready to go

Figure 6.9. Sample Application of OUTS and TREE (Sheet 2 of 2)

6.2.5. Activity BRCH

While OUTS and TREE can help detect absent branches, incorrect bus type codes, and system separations, they do nothing to help detect incorrect branch impedance data or branches where impedances might cause difficulties in converging power flow solutions. Activity BRCH is intended to detect unusual branch impedances. BRCH will detect and list the conditions summarized in Table 6.1, “Exceptional Branch Data Reports”.

Table 6.1. Exceptional Branch Data Reports

Selection Code	Condition	Default Threshold
1	Low-reactance branches	$X < 0.0005$
2	High-reactance branches	$X > 1.0$
3	Branches with low *X*/*R* ratio	$R > 0.67X$
4	Negative-reactance branches	$X < 0$
5	Buses with high ratio of highest to lowest reactance of connected branches	Ratio > 500
6	Large line-charging admittance	$Bch > 5.0$
7	Nonidentical parallel transformers	
8	Transformers with high tap ratio	t > 1.1
9	Transformers with low tap ratio	t < 0.9
10	Branches with zero sequence impedance of zero. Bypassed if sequence data not in case.	

To demonstrate the use of BRCH, consider a revision of the sample power system in which the dc transmission of Figure 6.14, “One-Line Diagram of Sample System” is replaced by 765-kV ac transmission (Figure 6.10, “765-kV ac Transmission Option for Sample System”). The removal of dc transmission and construction of the 765-kV ac transmission could be accomplished by a lengthy sequence of PSS®E console commands. It would be prudent to follow such a data change with data checking via activities OUTS, TREE, and BRCH. In the example, OUTS and TREE showed no errors. Activity BRCH was configured to run all of its data checks using its default threshold values.

Figure 6.11, “Report from Activity BRCH after Modifying System for Transmission as Shown in Figure 6.10, “765-kV ac Transmission Option for Sample System”” shows the report produced by BRCH, which reveals two data errors, which are probably the result of inaccurate data entry. The first error occurs in the report on branches with low reactance. It shows the branch 1500-1501 to have zero reactance and negative resistance. A check on Figure 6.10, “765-kV ac Transmission Option for Sample System” shows that this branch should be a capacitor and that the value appearing in the negative resistance field should be entered as reactance. It looks as if the resistance entry in the branch data was skipped in error; all other data for this branch should be checked via the spreadsheet view.

The second error appears in the high-reactance branch report, which shows a reactance of 13.94 for branch 1502-1600. Checking Figure 6.10, “765-kV ac Transmission Option for Sample System” shows this branch to be a 765-kV line, where charging, rather than reactance should be 13.94. Additional inspection shows a resistance entry of 0.0276, which should be the reactance. It looks as if the same error was made here as for branch 1500-1501.

These two errors were revealed by the first two check categories of BRCH. The same two errors were also caught by the checks on *X*/*R* ratio and on ratio of reactances connected to a bus. In addition to catching the branch data errors, BRCH summarizes the branches where reactances, while low or negative, are correct. Location of these branches is often necessary in order to improve the convergence of difficult power flow cases.

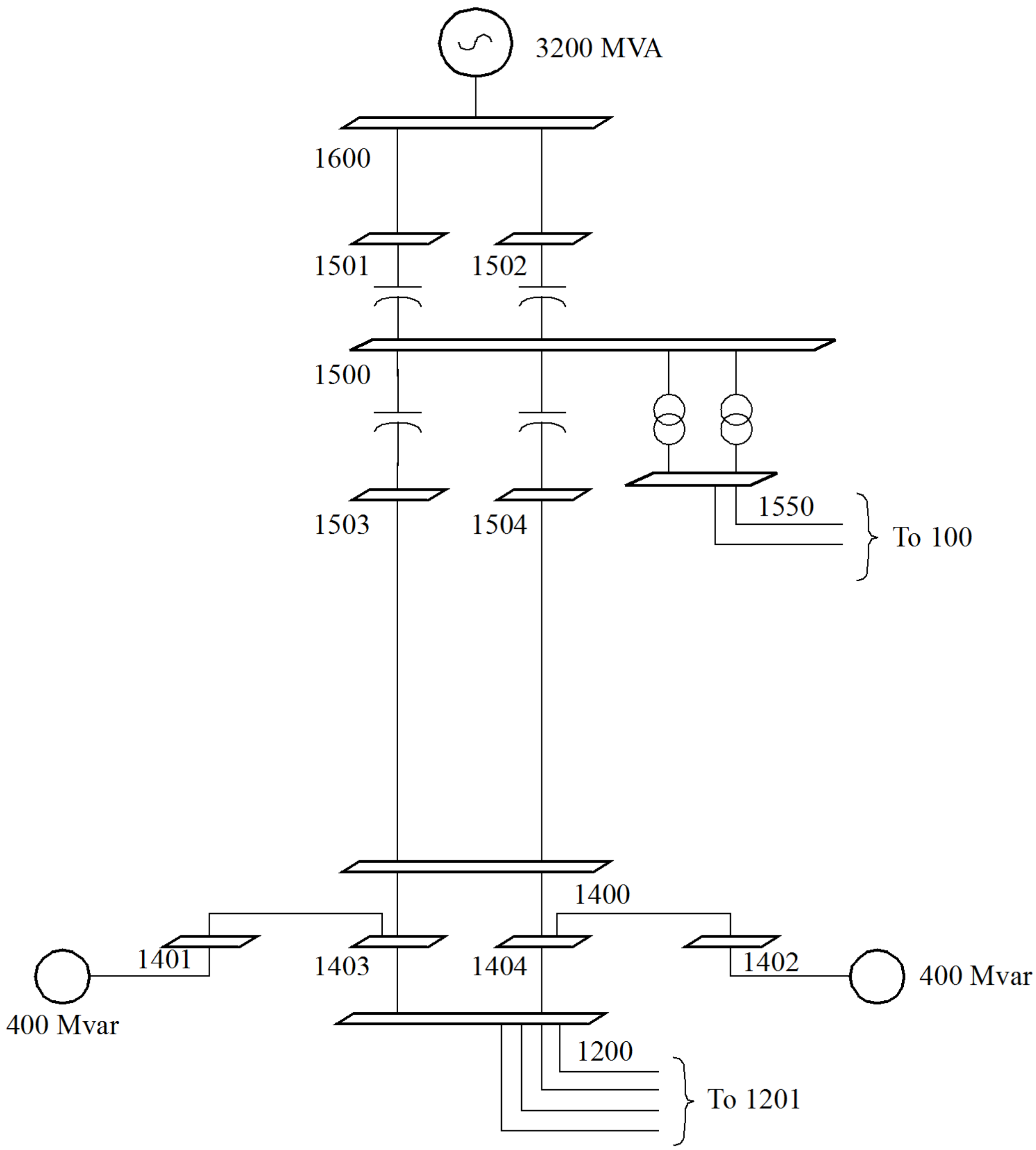


Figure 6.10. 765-kV ac Transmission Option for Sample System

```
     PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS®E      THU, DEC 09 1999  10:11
SAMPLE SYSTEM FOR PSS®E MANUAL
1100KV DC CASE

BRANCHES WITH [ /REACTANCE/ < 0.00050 ]:
                                                                           S
X--- FROM BUS ---X AREA X---- TO BUS ----X AREA CKT   LINE R    LINE X CHARGING T
 1200 STERML   230     3  1403 WDUM     18.0     3  1   0.00000 -0.00050  0.00000 1   OK, three-winding
 1200 STERML   230     3  1404 EDUM     18.0     3  1   0.00000 -0.00050  0.00000 1   transformer
 1500                  1  1501                   1  1  -0.00830  0.00010  0.00000 1
                                                                OOPS! Error - should be reactance, not
BRANCHES WITH [ /REACTANCE/ >  1.0000 ]:                        resistance
                                                                           S
X--- FROM BUS ---X AREA X---- TO BUS ----X AREA CKT   LINE R    LINE X CHARGING T
 1502                  1  1600 MINE      765     4  1   0.02760 13.94000  0.00000 1
                                                                    OH-OH! Goofed again; 13.94
BRANCHES WITH [ /R/ > 0.66667 * /X/ ]:                              looks like 765-kV charging value
                                                                           S
X--- FROM BUS ---X AREA X---- TO BUS ----X AREA CKT   LINE R    LINE X CHARGING T
 1500                  1  1501                   1  1  -0.00830   0.00010  0.00000 1

                                                                              Repeat of earlier
BRANCHES WITH [ REACTANCE < 0.0 ]:                                            error
                                                                           S
X--- FROM BUS ---X AREA X---- TO BUS ----X AREA CKT   LINE R    LINE X CHARGING T
 1200 STERML   230     3  1403 WDUM     18.0     3  1   0.00000 -0.00050  0.00000 1
 1200 STERML   230     3  1404 EDUM     18.0     3  1   0.00000 -0.00050  0.00000 1
 1500                  1  1502                   1  1   0.00000 -0.00830  0.00000 1
 1500                  1  1503                   1  1   0.00000 -0.00690  0.00000 1
 1500                  1  1504                   1  1   0.00000 -0.00690  0.00000 1


BUSES WITH BRANCHES HAVING [ (XMAX / XMIN) >  500.0 ]:
                                                                           S
X--- FROM BUS ---X AREA X---- TO BUS ----X AREA CKT   LINE R    LINE X CHARGING T
 1502                  1  1500                   1  1   0.00000 -0.00830  0.00000 1
 1502                  1  1600 MINE      765     4  1   0.02760 13.94000  0.00000 1
                                                                              Earlier error shows
 1600 MINE      765    4  1501                   1  1   0.00150  0.02760 13.94000 1   up again
 1600 MINE      765    4  1502                   1  1   0.02760 13.94000  0.00000 1


BRANCHES WITH [ CHARGING >  5.0000 ] OR NEGATIVE:
                                                                           S
X--- FROM BUS ---X AREA X---- TO BUS ----X AREA CKT   LINE R    LINE X CHARGING T
 1400                  1  1503                   1  1   0.00125  0.02300 11.62000 1   Branch 1501-1600
 1400                  1  1504                   1  1   0.00125  0.02300 11.62000 1   should show up here;
 1501                  1  1600 MINE      765     4  1   0.00150  0.02760 13.94000 1   it does not because
                                                                                      of the error
NON-IDENTICAL PARALLEL TRANSFORMERS:
                                                                                  S
X--- FROM BUS ---X AREA X---- TO BUS ----X AREA CKT     R         X      W1TAP     ANGLE  W2TAP  T

                                   * NONE *


TRANSFORMERS WITH [ RATIO > 1.10000 ]:
                                                                                  S
X--- FROM BUS ---X AREA X---- TO BUS ----X AREA CKT     R         X      W1TAP     ANGLE  W2TAP  T

                                   * NONE *


TRANSFORMERS WITH [ RATIO < 0.90000 ]:
                                                                                  S
X--- FROM BUS ---X AREA X---- TO BUS ----X AREA CKT     R         X      W1TAP     ANGLE  W2TAP  T


                                   * NONE *
```

Figure 6.11. Report from Activity BRCH after Modifying System for Transmission as Shown in Figure 6.10, “765-kV ac Transmission Option for Sample System”

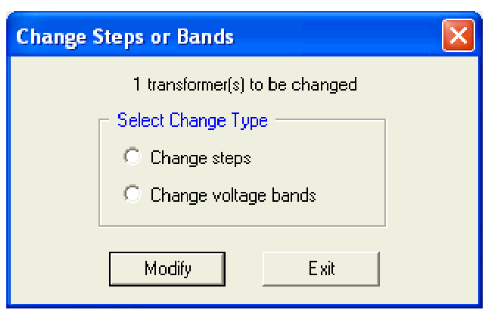
6.2.6. Activity TPCH

Activity TPCH detects errors or problems in the adjustment data associated with voltage or flow controlling transformers. It is extremely useful in finding problems caused by data entry errors where a number entered is off by a magnitude. Activity TPCH is also helpful in finding data specified for transformers that may cause difficulties in eventual power flow convergence. A list of the checks run by TPCH is shown in Table 6.2, "Transformer Adjustment Data Checking Reports".

Table 6.2. Transformer Adjustment Data Checking Reports

Selection Code	Type of Controlling Transformer	Condition	Default Threshold
1	Voltage or Mvar	No Tap-Step Specified	STEP=0.
2	Voltage or Mvar	Small Tap-Step	0.<STEP<0.00625
3	Voltage or Mvar	Large Tap-Step	STEP>0.00625
4	Voltage	Band Small Compared to Tap-Step Size	BAND<2*STEP
5	Voltage	Small Voltage Band	BAND<0.02
6	Voltage	Large Voltage Band	BAND>0.02
8	MW or Mvar	Small Flow Band	Band<5.0
9	MW or Mvar	Large Flow Band	Band>5.0

In addition to checking for possible data problems, activity TPCH also gives the user the ability to modify the data. Figure 6.12, "Activity TPCH Report" shows an example where two transformers had a voltage band specified that was less than twice the tap-step. Problems can arise in the solution because a transformer step in either direction could cause the voltage to go out of its specified band. In Figure 6.12, "Activity TPCH Report" the band was increased at all the transformers to avoid any problems by clicking **Modify**. The band is automatically increased to twice the step about the middle of the previously specified voltage band.




```
   VOLTAGE CONTROLLING TRANSFORMERS WITH VOLTAGE BAND < 2*STEP
   X--- ADJUSTABLE SIDE ---X  X--------- TO ----------X
     BUS# X-- NAME --X BASKV    BUS# X-- NAME --X BASKV CKT     VMAX      VMIN      BA
 POSITIONS STEP
      151 NUCPANT      500.00     101 NUC-A        21.600  1    0.99500   0.98500   0.010
 33   0.00625
        1 TRANSFORMERS FOUND
```

Figure 6.12. Activity TPCH Report

6.3. Data Listing

6.3.1. Report Selection and Routing

All PSS®E reporting activities allow the user to examine the contents of the working files. Reports may list both system data, such as branch impedances, or computed quantities, such as branch flows, or a combination of both. All reports list the current condition of the working file whether or not the bus voltage vector is a solution of Kirchhoff's laws. Reports may range from complete tabulations of all system data on the line printer to a quick display of a very limited subset of data on the CRT screen. Each reporting activity allows the user to specify both the device to which the report is to be routed, and the section of the power system on which data is to be reported. Provision for tailoring report output device selection is provided in PSS ®E.

Output selection must be made each time a reporting function is initiated. The report selection criteria are applied to buses. When selection is invoked, the reporting activities scan the entire working file, as for an all-inclusive report, but suppress listing of output for any item of equipment that is not connected to a bus that meets the selection criteria. More than one selection criterion may be invoked at a time; simultaneously invoked criteria are treated as a logical and criterion, a bus must satisfy all active selection criteria before output will be printed.

Figure 6.13, "Report Selection Dialog" shows the choice of area 2 for a reporting function.

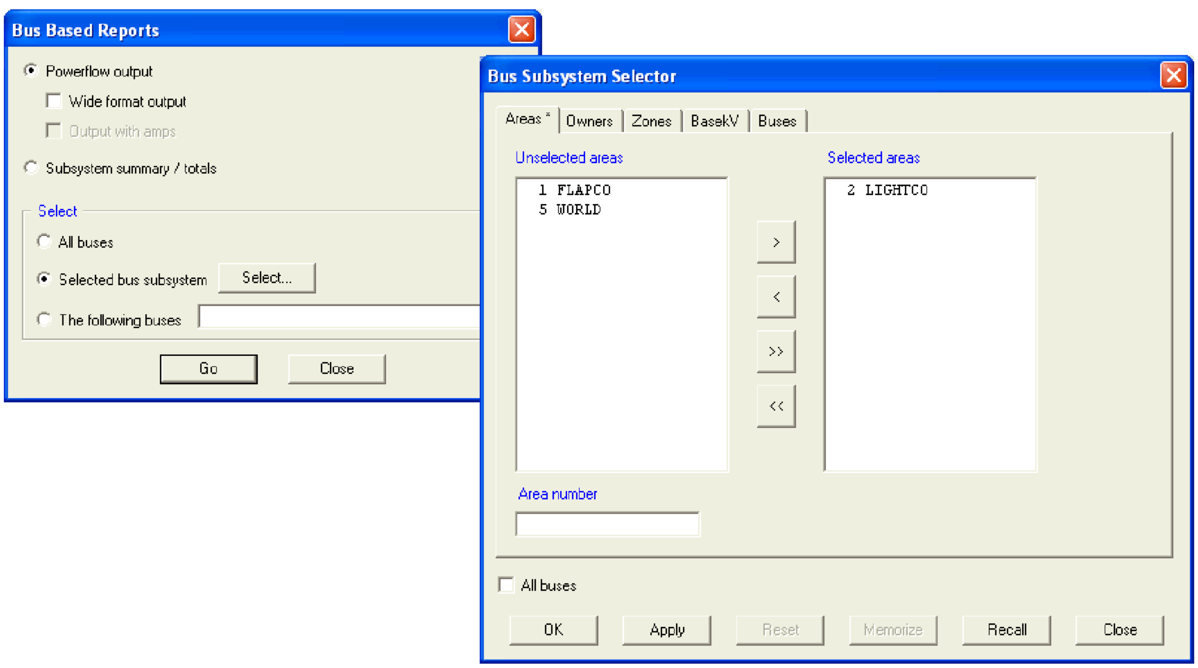


Figure 6.13. Report Selection Dialog

6.3.2. Activity LIST

Activity LIST, run by selecting *Power Flow>List Data...* (*Powerflow*), is intended primarily for archival and reference listings. Its report is an ordered and formatted restatement of the basic power flow problem data, most often routed to bulk output devices like files or line printers.

Figure 6.1, "Activity LIST Report (Sheet 1 of 5)" shows the complete LIST report for the data shown in Figure 6.17, "Power Flow Raw Data File INDAT". The output report of LIST is mainly self-explanatory; annotations explain items where significance is not self-evident. Activity LIST is not generally convenient for interactive searching or bus-by-bus examination of system data. This task is best handled by activity EXAM.

6.3.3. Activity EXAM

Activity EXAM, run by selecting *Power Flow>List Data...* (*Examine Powerflow/sequence data*), is intended for use in interactive data examination. Its display is a summary of all data pertaining to a single bus. EXAM is, in effect, a very selective version of LIST with a modified format designed for the CRT display. Figure 6.6, "Single-Screen Display of All Data Pertaining to Bus 300 From Activity RATE" shows a sample display from EXAM.

6.4. Example Setup

6.4.1. General Sequence

The overall sequence of steps in setting up a new power flow case follows:

1. Establish the initial set of system data in a power flow raw data file. In most instances this will be achieved by reading information supplied by a power pool or similar data management organization. Raw data files describing reasonably small systems may be keyed via the computer's text editor.

2. Establish the name of a power flow saved case file that will accommodate the system model that is about to be built.

3. Read power flow input data to pick up data records from the raw data file and build the system model in the power flow working files.

4. Use the various PSS®E data listing and checking activities to examine the system model for correctness of such overall characteristics as load level, total generation, network separation, and so on.

5. Correct data errors by any of the following methods:

   Correct the power flow raw data file and return to Step 3 if the errors involve incorrect model construction.

   Edit parameter values if they need to be changed.

   Add and edit power flow data if components have to be added or changed.

6. Record the corrected up-to-date system model in the saved case file specified in Step 2.

7. Solve the power flow case, adjust system conditions and resolve as necessary, until a valid base case system operating condition is achieved.

8. Each time a solution is judged to be an improvement over the previous trial in Step 7, record it in the saved case file that was selected in Step 2 and used initially in Step 6.

6.4.2. Sample Basic System Model Setup

Figure 6.14, "One-Line Diagram of Sample System" shows a one-line diagram of a small sample power system. Figure 6.15, "PSS®E File Planning Sheet" shows a PSS®E File Planning Sheet containing the names of the files to be used in a base case system model setup. File extensions have been purposely omitted because they are computer-dependent.

The process of getting off the ground is shown schematically in Figure 6.16, "Schematic Sequence of Steps in Initial Setup of a PSS®E Power System Model". The raw data could come from either an external source or from the user's own idea, but, in either case, it is ultimately contained in the file named INDAT. Figure 6.17, "Power Flow Raw Data File INDAT" shows a complete listing of file INDAT.

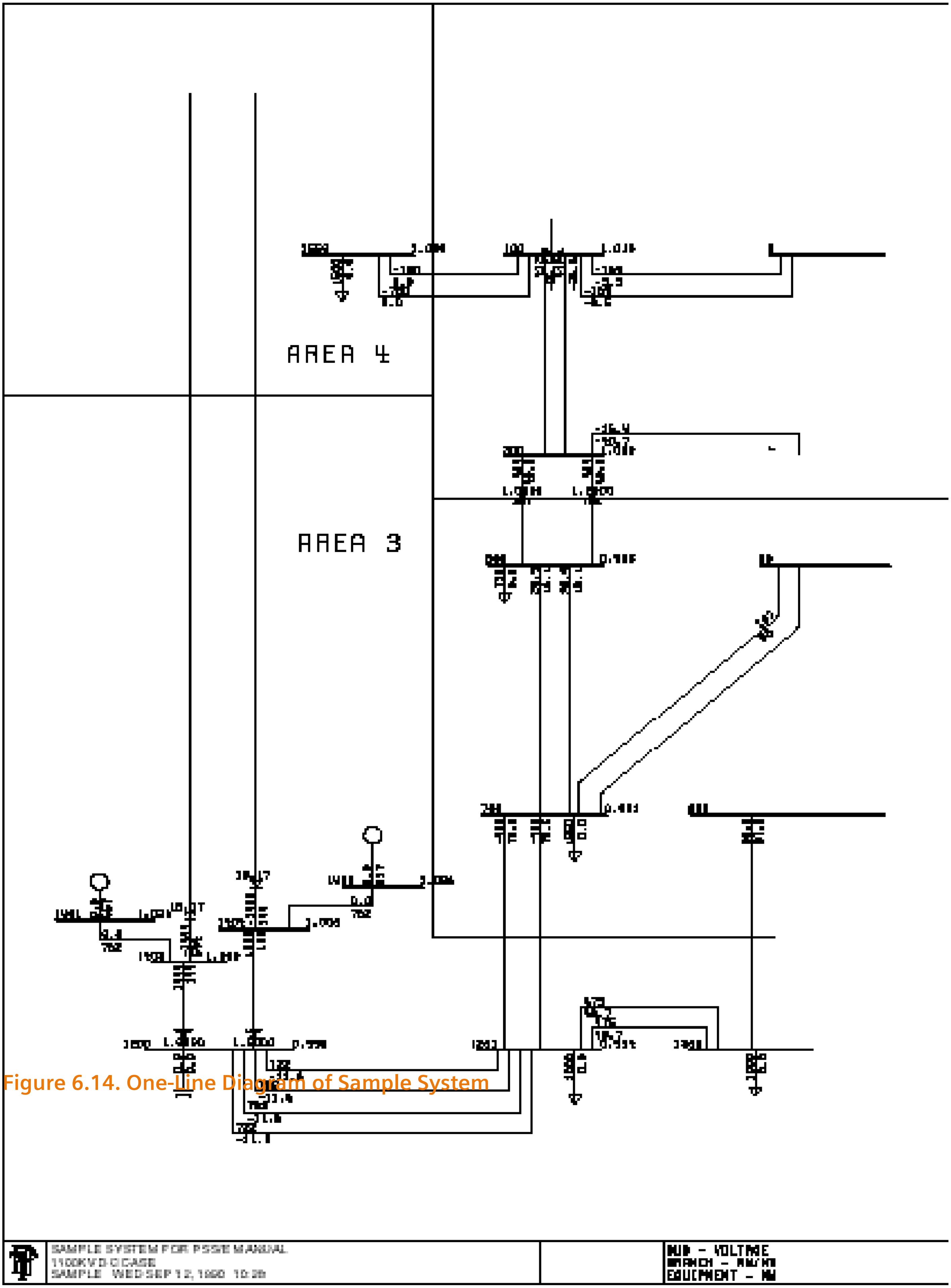


Figure 6.14. One-Line Diagram of Sample System

Figure 6.15. PSS®E File Planning Sheet

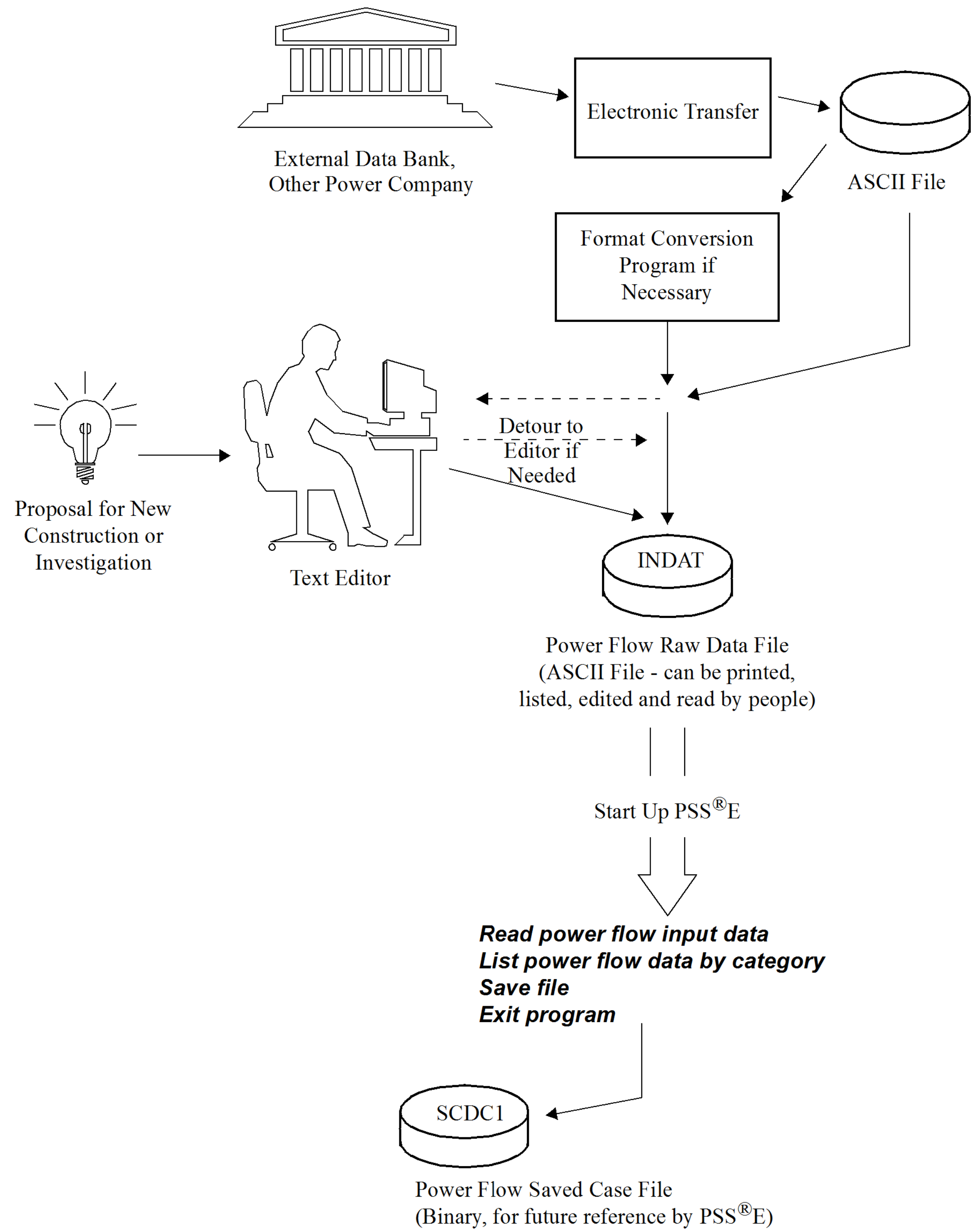


Figure 6.16. Schematic Sequence of Steps in Initial Setup of a PSS®E Power System Model

Figure 6.17. Power Flow Raw Data File INDAT

Figure 6.18. Power Flow Raw Data File INDAT(Contd)

The progress area for the initial power system model setup is shown in Figure 6.19, "Dialog from Progress Area for Initial System Model Setup". The user sees confirmation of data being read and saved in file SCDC1.sav. The raw data file INDAT has served its purpose and is used again only if a subsequent review of the system model reveals construction errors such as missing buses.

```
 Executing activity READ,ALL
  ENTER IC, SBASE
  ENTER TWO LINE HEADING
  ENTER BUS DATA
  ENTER LOAD DATA
  ENTER GENERATOR DATA
  ENTER NON-TRANSFORMER BRANCH DATA
  ENTER TRANSFORMER DATA
  ENTER AREA INTERCHANGE DATA
  ENTER TWO-TERMINAL DC LINE DATA
  ENTER VSC DC LINE DATA
  ENTER SWITCHED SHUNT DATA
  ENTER TRANSFORMER IMPEDANCE CORRECTION DATA
  ENTER MULTI-TERMINAL DC LINE DATA
  ENTER MULTI-SECTION LINE DATA
  ENTER ZONE NAME DATA
  ENTER INTER-AREA TRANSFER DATA
  ENTER OWNER NAME DATA
  ENTER FACTS DEVICE DATA
 Executing activity SAVE


   CASE SAVED IN FILE C:\Program Files\PTI\PSSE30\EXAMPLE\savnw.sav ON
MON, JUL 12 2004  11:40
```

Figure 6.19. Dialog from Progress Area for Initial System Model Setup

6.5. Overview

PSS®E functions like a very powerful hand-held calculator. Its working files are analogous to the calculator's display register and its activities to its function buttons. The engineer uses PSS®E by setting up a power system model in the working file and operating on this model with PSS®E activities. Theoretical points pertaining to the setup of the power system model were covered in Chapter 5. This chapter covers specific procedures, data file arrangements, and activity sequences needed to produce power flow study results from PSS®E.

6.6. Power Flow Output

6.6.1. General Points

The principal activities producing power flow results reports are summarized in Table 6.3, "Power Flow Results Reports", together with the selection options recognized. The following points should be noted in connection with all power flow output reporting:

1. All branch flows are total flow through the line terminals and include the current flowing into charging capacitance and line-connected reactors.

2. Where appropriate, the metered end of a branch is indicated by an asterisk after the metered-end bus number.

3. Net interchanges for both areas and zones are based on flows at the metered end of each branch.

4. All checks of branch flow against loading are made by calculating loading at both ends and comparing the larger of the two with the rating.

Table 6.3. Power Flow Results Reports

Activity	Selection Suffixes Recognized	Function
POUT , LOUT	ALL, AREA,ZONE, OWNER, KV, OPT	Comprehensive power flow output.
RATE , OLTL , OLTR	AREA, ZONE, OWNER, KV, OPT	Summary of branches exceeding specified percentage of selected rating.
VCHK	AREA, ZONE, OWNER, KV, OPT	Summary of buses with voltage outside specified band.
AREA , ZONE	AREA ZONE	Summary of area or zone totals of load, generation, net interchange, and losses.
TIES , INTA	AREA	Summary of tie-line flows between areas.
TIEZ , INTZ	ZONE	Summary of tie-line flows between zones.
GEOL	ALL, AREA, ZONE, OWNER, KV, OPT	Summary of generator terminal loading conditions on either all, or only overloaded, generators.
GENS	ALL, AREA, ZONE, OWNER, KV, OPT	Summary of generator bus loading conditions on either all, or only var-limited, generators.
SUBS	ALL, AREA, OWNER, ZONE, KV, OPT	Summary of a specified subsystem.
OUTS , MTDC	ALL, AREA, ZONE, OWNER, KV, OPT None	Summary of out-of-service equipment. Solution output of dc buses in multiterminal dc lines.

6.6.2. Ordering of Reports

All power flow output reports may be organized either numerically by ascending bus number, or alphabetically by bus name. Ordering is obtained with activity OPTN and either the numbers output option, or the names output option. Changing between the numbers and names input options has no effect on the ordering of power flow reports.

All reports, except those selected by the AREA,ZONE and OWNR criterion, are made with buses appearing in pure numeric or alphabetic order. Power flow results reports selected by these order the buses numerically or alphabetically within groupings; for example, Activity POUT,AREA, with areas 2 and 6 selected, will list all buses in area 2 first and then all buses in area 6.

Special orders and groupings of power flow output are best handled by establishing response files to create standardized reports.

6.6.3. Activity POUT

Activity POUT, run by selecting *Power Flow>Reports>Bus based reports...*, produces full power flow output in the formats shown in Figure 6.20, "Sample Output from Activity POUT with Numerical Ordering PSS®E Numbers Option in Effect" and Figure 6.21, "Sample Output from Activity POUT with Alphabetical Ordering PSS®E Names Option in Effect". Figure 6.20, "Sample Output from Activity POUT with Numerical Ordering PSS®E Numbers Option in Effect" shows the narrow, numerical order format produced when PSS®E is run using the bus number option for output. Figure 6.21, "Sample Output from Activity POUT with Alphabetical Ordering PSS®E Names Option in Effect" shows the wide, alphabetical order, format produced when the bus name output option of PSS ®E is in effect.

The left-hand sections of the two report formats contain the same numerical information and differ only in their ordering. The additional section on the right of the alphabetic format gives the area name and zone number for each bus and the losses in each individual branch. Branch losses are calculated as the algebraic sum of the computed values of complex power flowing into the two ends of the branch.

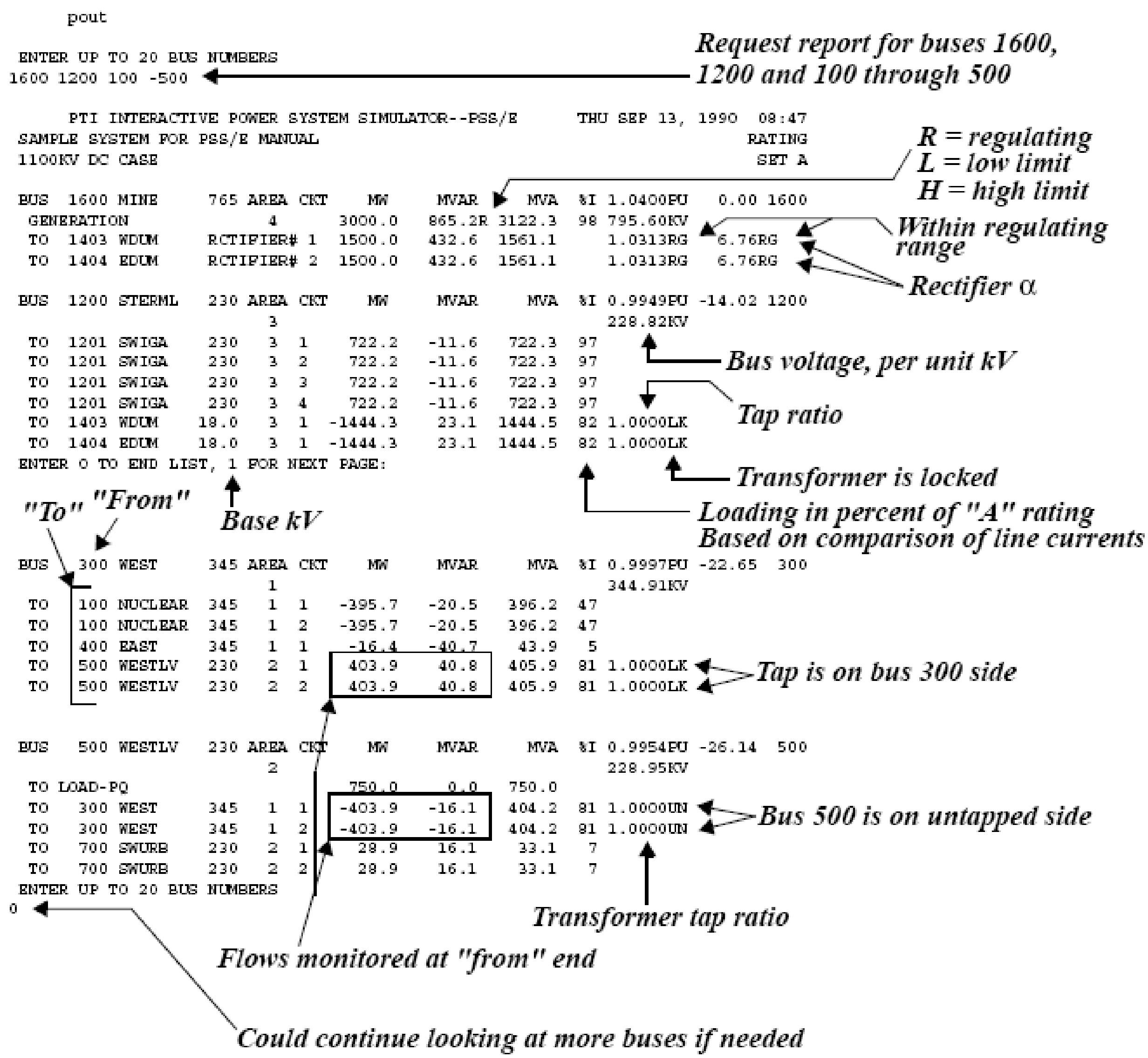


Figure 6.20. Sample Output from Activity POUT with Numerical Ordering PSS®E Numbers Option in Effect

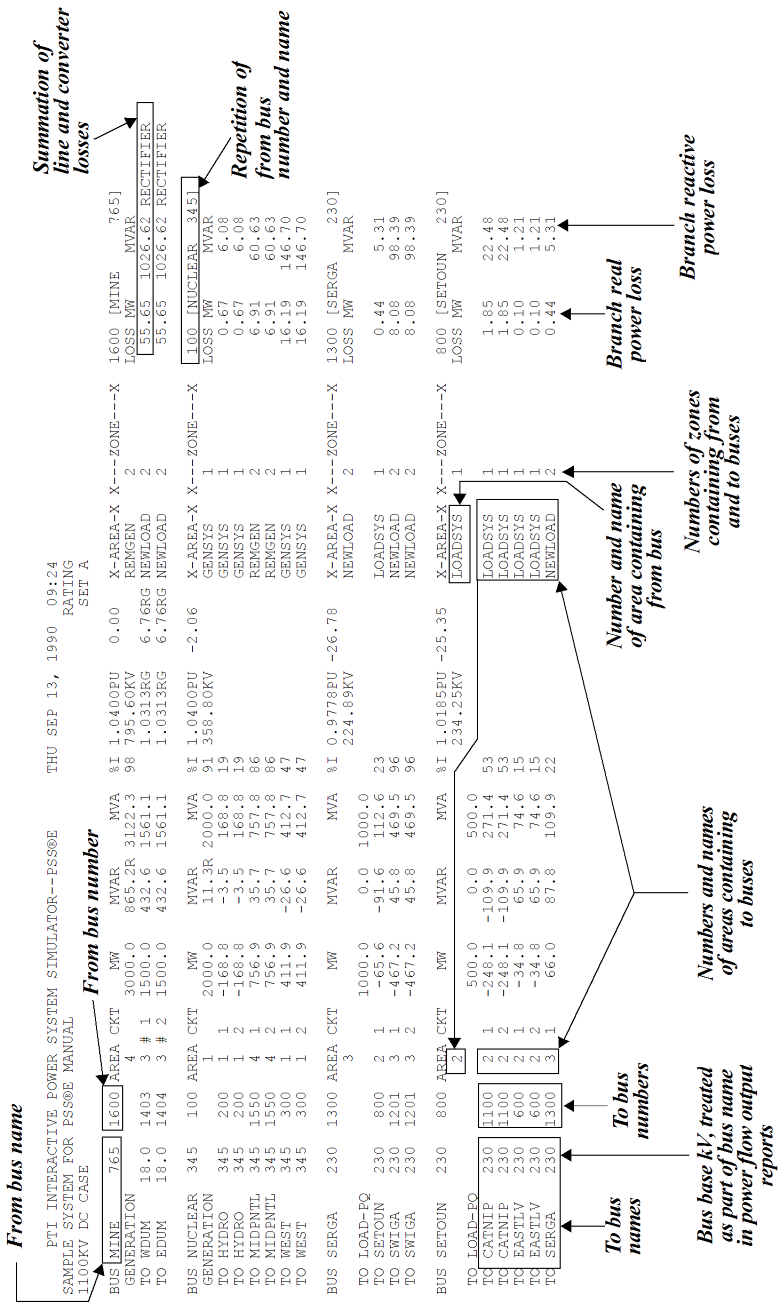


Figure 6.21. Sample Output from Activity POUT with Alphabetical Ordering PSS®E Names Option in Effect

The activity POUT formats are largely self-explanatory. The following notes apply:

1. The % column gives the branch loading as a percentage of the rating of the branch set by activity OPTN (A is default), if present in the saved case. Loadings of branches and transformers are determined in the same way as in activity RATE (see Section 6.6.7, "Activity RATE").

2. Transformer tap ratio is printed both when the from bus is the tapped side and when the to bus is the tapped side. When the to bus is the tapped side, the ratio is followed by the flag UN, regardless of whether it is on limit, regulating, or locked. The flags printed after the transformer ratio when the from bus is the tapped side are these:

   LO When ratio is on low limit.

   HI When ratio is on high limit.

   RG When ratio is in regulating range.

   LK When ratio is locked.

3. The branch reactive power loss shown by POUT in Figure 6.21, "Sample Output from Activity POUT with Alphabetical Ordering PSS®E Names Option in Effect" is the algebraic sum of the positive losses in the line series inductance and shunt reactors and the negative losses in charging capacitance and shunt capacitors. Hence, a negative value of branch reactive power loss indicates that the branch provides a net supply of vars to the system.

6.6.4. Activities TIES, TIEZ, INTA, and INTZ

Activity TIES, run by selecting *Power Flow>Reports>Area / zone based reports...* (*Tie line*), summarizes the flows on all tie-lines leaving interchange control areas. Figure 6.22, "Sample Output from Activity TIES" shows a sample report. Unlike activity POUT, which always prints the flow at the from end of a branch, activity TIES always prints flow at the metered end, regardless of whether the meter is at the from or to end. This is apparent in Figure 6.20, "Sample Output from Activity POUT with Numerical Ordering PSS®E Numbers Option in Effect" through Figure 6.22, "Sample Output from Activity TIES". In Figure 6.20, "Sample Output from Activity POUT with Numerical Ordering PSS®E Numbers Option in Effect", for example the flows shown from 300 to 500, and from 500 to 300, differ by the I^2 *Z* loss of the branch. In Figure 6.22, "Sample Output from Activity TIES", in contrast, the flows shown from 700 to 1201, and from 1201 to 700, are identical.

The effective boundary of an area is always at the metered end of each tie branch, as shown in Figure 6.23, "Position of Effective Area Boundary with Respect to Tie-Line Meter Locations". Activity TIES sums the tie branch flows to give the net interchange of the area. Tie flow and net interchange are taken to be *positive when flowing out* of the area being reported. Hence, in the example shown in Figure 6.23, "Position of Effective Area Boundary with Respect to Tie-Line Meter Locations", the losses of branches 100-305 and 511-617 are an internal loss of area 3, while the loss of branch 308-796 is an external loss and is charged to area 5.

Often the user is only interested in the total interchange between areas. Activity INTA, run by selecting *Power Flow>Reports>Area / zone based reports...* (*Inter area / zone flow*), using the conventions of activity TIES, summarizes in matrix form the real power flows between areas.

Figure 6.24, "Sample Output from Activity INTA" shows a sample report. Note that interchanges between areas are the same as shown in Figure 6.22, "Sample Output from Activity TIES".

Activities TIEZ and INTZ summarize the flows on all tie-lines leaving zones. Their format and metering convention are as those of Activities TIES and INTA.

```
ACTIVITY? ties,area
ENTER UP TO 20 AREA NUMBERS
2,3

     PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS/E      TUE JUL 13, 1993  15:29
SAMPLE SYSTEM FOR PSS/E MANUAL                                  AREA TIE LINE
1100KV DC CASE                                                    INTERCHANGE

FROM AREA    2    LOADSYS

  TO AREA    1    GENSYS
  X-------FROM------X X--------TO-------X CKT      MW      MVAR
  EASTLV    230    600  EAST     345    400*  1    -421.8    -1.6
  EASTLV    230    600  EAST     345    400*  2    -421.8    -1.6
  WESTLV    230    500  WEST     345    300*  1    -403.9   -40.8
  WESTLV    230    500  WEST     345    300*  2    -403.9   -40.8
  TOTAL FROM AREA    2 TO AREA    1                             -1651.3     -84.9

  TO AREA    3    NEWLOAD
  X-------FROM------X X--------TO-------X CKT      MW      MVAR
  SETOUN    230    800* SERGA    230  1300    1     66.0     87.8
  SWURB     230    700* SWIGA    230  1201    1   -459.7     73.6
  SWURB     230    700* SWIGA    230  1201    2   -459.7     73.6
  TOTAL FROM AREA    2 TO AREA    3                              -853.4     235.0
                                                                --------  --------
TOTAL FROM AREA    2                                            -2504.7     150.2
```

Get tie line report, selective by area

Report ties leaving areas 2 and 3

Area 2 net interchange

```
     PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS/E      TUE JUL 13, 1993  15:29
SAMPLE SYSTEM FOR PSS/E MANUAL                                  AREA TIE LINE
1100KV DC CASE                                                    INTERCHANGE

FROM AREA    3    NEWLOAD

  TO AREA    2    LOADSYS
  X-------FROM------X X--------TO-------X CKT      MW      MVAR
  SERGA     230   1300  SETOUN   230    800*  1    -66.0    -87.8
  SWIGA     230   1201  SWURB    230    700*  1    459.7    -73.6
  SWIGA     230   1201  SWURB    230    700*  2    459.7    -73.6
  TOTAL FROM AREA    3 TO AREA    2                               853.4    -235.0

  TO AREA    4    REMGEN
  X-------FROM------X X--------TO-------X CKT      MW      MVAR
  WDUM      18.0  1403* MINE     765  1600       -1444.3    590.9 TWO TRM DC #  1
  EDUM      18.0  1404* MINE     765  1600       -1444.3    590.9 TWO TRM DC #  2
  TOTAL FROM AREA    3 TO AREA    4                             -2888.7    1181.8
                                                                --------  --------
TOTAL FROM AREA    3                                            -2035.3     946.8
ENTER UP TO 20 AREA NUMBERS
0
```

Interchange 2 - 3 and 3 - 2 equal and opposite

Flows monitored at metered end

Area 3 net interchange

Figure 6.22. Sample Output from Activity TIES

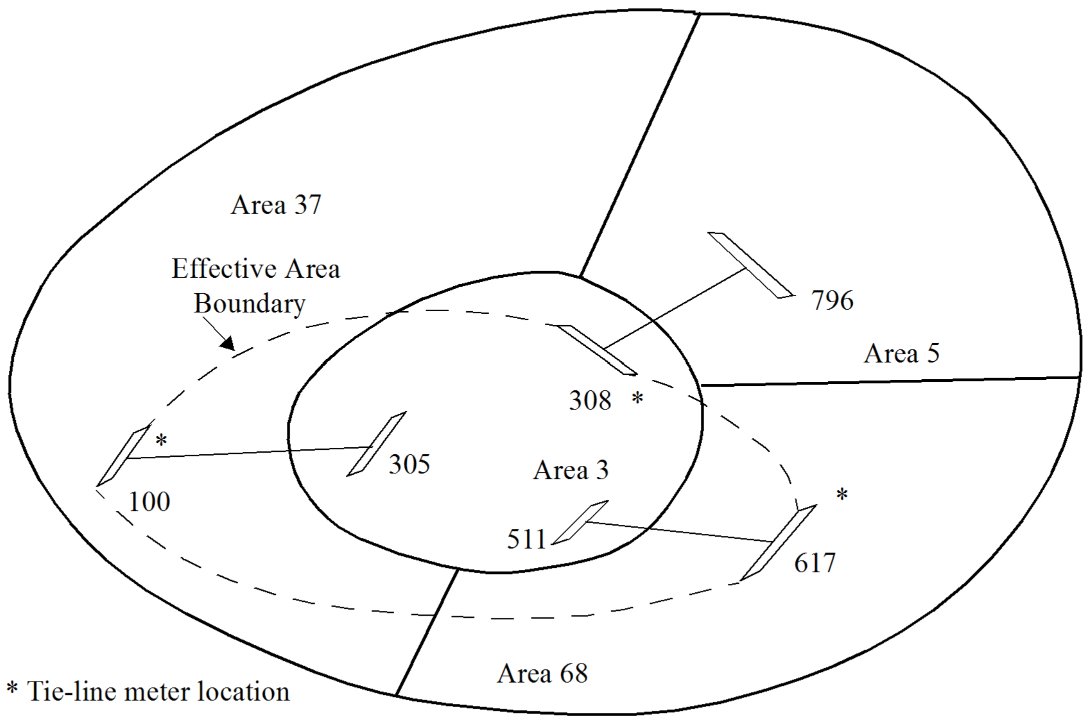


Figure 6.23. Position of Effective Area Boundary with Respect to Tie-Line Meter Locations

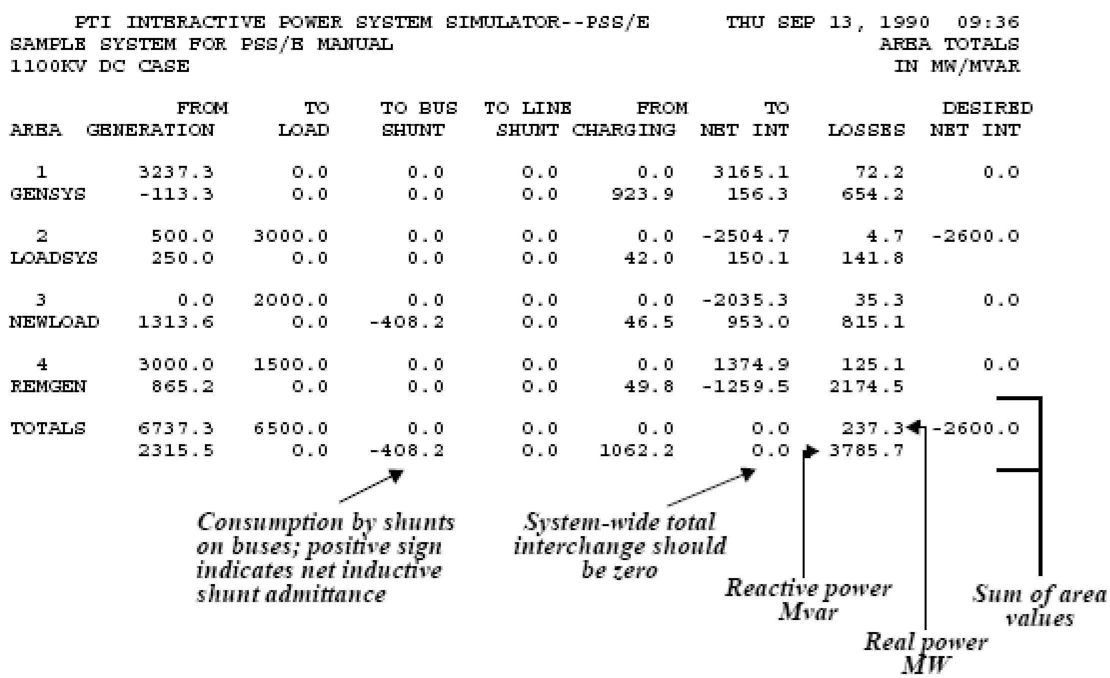
```
     PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS®E      THU SEP 13, 1990  09:29
SAMPLE SYSTEM FOR PSS®E MANUAL                                          AREA
1100KV DC CASE                                                     INTERCHANGE

     TO AREA   1      2      3      4
FROM AREA*------------------------
       1 *          1651          1514
GENSYS   *            85            71
         *------------------------
       2 * -1651          -853
LOADSYS  *    -85           235
         *------------------------
       3 *           853         -2889
NEWLOAD  *          -235          1188
         *------------------------
       4 * -1514          2889
REMGEN   *    -71         -1188
         *------------------------
```

Figure 6.24. Sample Output from Activity INTA

6.6.5. Activity AREA

The report of activity AREA, run by selecting *Power Flow>Reports>Area / owner / zone totals...*, is shown in Figure 6.25, "Sample Output From Activity AREA". This report summarizes totals, generation, load, and other key quantities for each area. Net interchange is evaluated according to the tie branch metered-end designations (Section 6.6.4, "Activities TIES, TIEZ, INTA, and INTZ"). Losses are calculated from actual line losses, not generation minus load. Hence, in Figure 6.23, "Position of Effective Area Boundary with Respect to Tie-Line Meter Locations", the losses of branches 100-305 and 511-617 are charged in full to area 3, while the full losses of branch 308-796 are charged to area 5.

Line-connected shunt reactors and capacitors are regarded as sources of line charging Mvar; their reactive power flows respectively decrease and increase the reactive power supplied by branch charging capacitance. Both fixed and switched shunt capacitances at buses are regarded as negative shunt load, while shunt reactors at buses are treated as positive shunt load.



```
     PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS/E      THU SEP 13, 1990  09:36
SAMPLE SYSTEM FOR PSS/E MANUAL                                   AREA TOTALS
1100KV DC CASE                                                    IN MW/MVAR

             FROM        TO    TO BUS  TO LINE     FROM       TO            DESIRED
AREA   GENERATION      LOAD     SHUNT    SHUNT CHARGING  NET INT    LOSSES  NET INT

  1        3237.3       0.0       0.0      0.0      0.0   3165.1      72.2      0.0
GENSYS     -113.3       0.0       0.0      0.0    923.9    156.3     654.2

  2         500.0    3000.0       0.0      0.0      0.0  -2504.7       4.7  -2600.0
LOADSYS     250.0       0.0       0.0      0.0     42.0    150.1     141.8

  3           0.0    2000.0       0.0      0.0      0.0  -2035.3      35.3      0.0
NEWLOAD    1313.6       0.0    -408.2      0.0     46.5    953.0     815.1

  4        3000.0    1500.0       0.0      0.0      0.0   1374.9     125.1      0.0
REMGEN      865.2       0.0       0.0      0.0     49.8  -1259.5    2174.5

TOTALS     6737.3    6500.0       0.0      0.0      0.0      0.0     237.3  -2600.0
           2315.5       0.0    -408.2      0.0   1062.2      0.0    3785.7
```


Figure 6.25. Sample Output From Activity AREA

6.6.6. Activity ZONE

Activity ZONE produces a report using the same conventions and format as the AREA report, giving totals for every zone in the system. It is run from the same menu as AREA.

6.6.7. Activity RATE

A sample branch overload summary produced by activity RATE, is run by selecting *Power Flow>Reports>Limit checking reports...* (*Branches* tab), is shown in Figure 6.26, " Sample Output from Activity RATE". Activity

RATE computes the loading of every branch in the system, or selected subsystem, compares it with a rating, and prints an alarm if the loading exceeds the rating. Branch ratings are made by calculating phase current:

$$I_{actual} = \frac{MVA_{actual} \times 10^3}{\sqrt{3} \times V_{pu} \times kV_{base}}$$

where branch rated current is taken to be:

$$I_{rated} = \frac{MVA_{rated} \times 10^3}{\sqrt{3} \times kV_{base}}$$

and the percentage loading is then:

$(I_{actual} / I_{rated}) \times 100$

Transformer rating checks in activity RATE are made on the same *current* basis as for transmission lines.

Activity OLTL runs the same type of current overload test for transmission lines and ignores transformers. Activity OLTR checks transformer branches only, and checks loading on the basis of MVA rather than the current as in activities RATE and OLTL.

The LOADING column in the report from RATE gives the branch current loading in terms of MVA at base voltage. That is, the loading printed in this column is:

Loading = $\sqrt{3} \times I_{actual} \times V_{base}$

Figure 6.26, " Sample Output from Activity RATE" shows, for example, that the loading in the circuits from 700 to 1201 is 470.4 MVA. The phase current is given, then, by:

$470.4 \times 10^6 = \sqrt{3} \times I_{actual} \times (230 \times 10^3)$

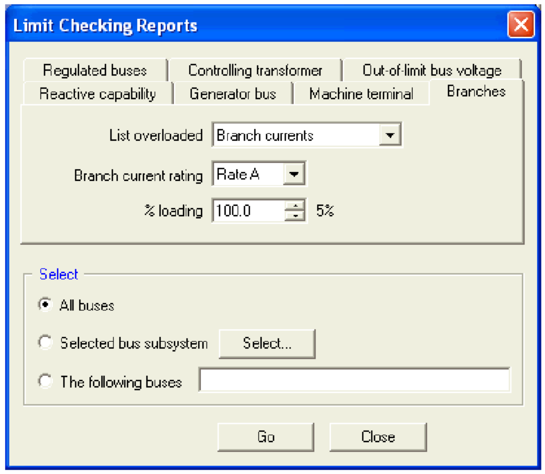
$I_{actual} = 1180.8$ A

The rated current is:

$I_{rated} = 500 \times 10^6 / [\sqrt{3} \times (230 \times 10^3)]$

= 1255.2 A

and the resulting percentage loading is (1180.8 / 1255.2) * 100 = 94.1.



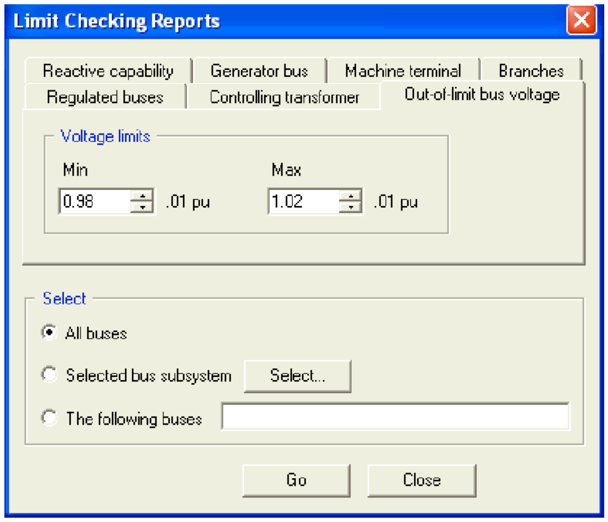

```
     PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS®E      THU, DEC 09 1999  15:04
SAMPLE SYSTEM FOR PSS®E MANUAL
1100KV DC CASE

BRANCH LOADINGS ABOVE  90.0 % OF RATING SET A:

X-------FROM BUS-------X  X--------TO BUS--------X        CURRENT(MVA)
  BUS     NAME   BSKV  AREA    BUS     NAME   BSKV  AREA  CKT  LOADING  RATING  PERCENT
  700   SWURB     230    2    1201*  SWIGA     230    3  1     470.4    500.0    94.1
  700   SWURB     230    2    1201*  SWIGA     230    3  2     470.4    500.0    94.1
 1200*  STERML    230    3    1201   SWIGA     230    3  1     726.0    750.0    96.8
 1200*  STERML    230    3    1201   SWIGA     230    3  2     726.0    750.0    96.8
 1200*  STERML    230    3    1201   SWIGA     230    3  3     726.0    750.0    96.8
 1200*  STERML    230    3    1201   SWIGA     230    3  4     726.0    750.0    96.8
 1201*  SWIGA     230    3    1300   SERGA     230    3  1     480.1    500.0    96.0
 1201*  SWIGA     230    3    1300   SERGA     230    3  2     480.1    500.0    96.0
```

Figure 6.26. Sample Output from Activity RATE

The actual MVA flows into the branches from 700 to 1201 are 465.6 MVA at 0.9910 per-unit voltage at bus 700 and 467.6 MVA at 0.9941 per-unit voltage at bus 1201. The 1285.5 A phase currents exists at the 1201 end of these circuits. The phase current at the middle of each circuit differs from the current at either end by the amount of the charging capacitive currents.

6.6.8. Activity VCHK

Figure 6.28, "Sample Selective Output from Activity VCHK Showing No Voltages Outside Default Range" and Figure 6.27, "Sample Output from Activity VCHK Showing Buses with Voltages Outside a Tight Checking Range" show voltage summaries as produced by activity VCHK, run by selecting *Power Flow>Reports>Limit checking reports...* (*Out-of-limit bus voltage* tab). Voltages are always checked in per-unit terms. The per-unit quantities, VMAX and VMIN, are entered by the user to set the upper and lower voltage checking limits. Every bus voltage is checked against these per-unit limits regardless of whether a base voltage value is present for the bus.

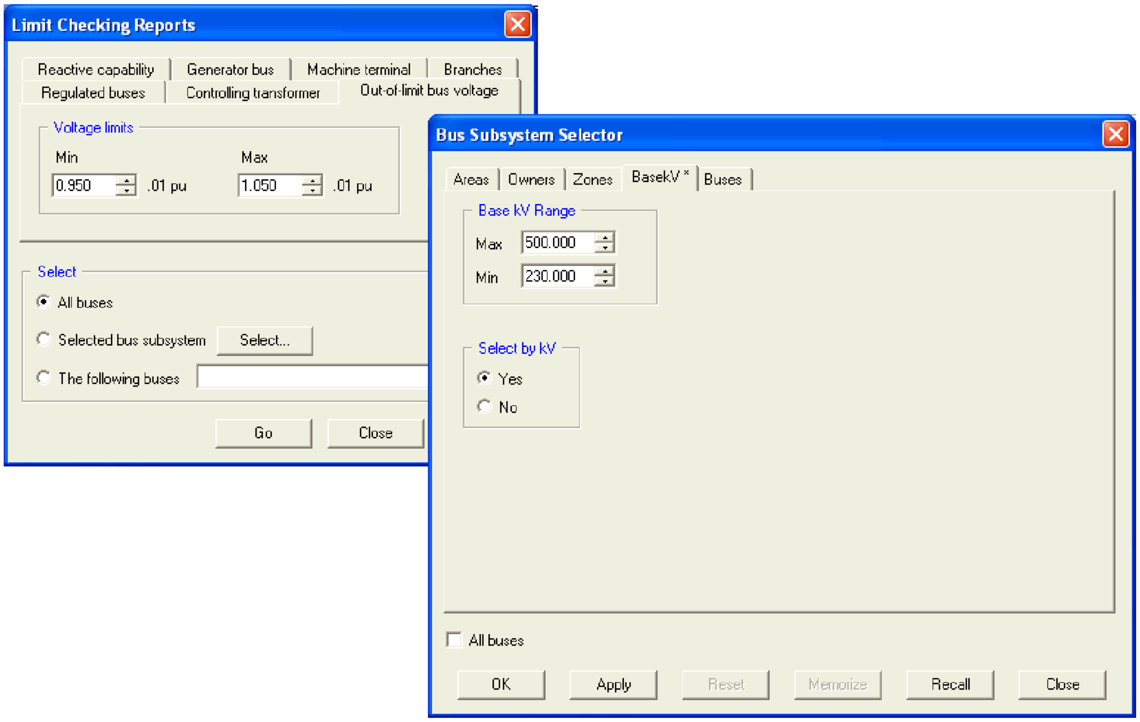



```
      PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS®E      THU, DEC 09 1999
15:15
 SAMPLE SYSTEM FOR PSS®E MANUAL
 1100KV DC CASE

 BUSES WITH VOLTAGE GREATER THAN 1.0200:

 X------ BUS -----X AREA V(PU)  V(KV)    X------ BUS -----X AREA V(PU)  V(KV)
   100 NUCLEAR  345    1 1.0400 358.80      200 HYDRO     345    1 1.0400 358.80
  1100 CATNIP   230    2 1.0610 244.03     1401 WCOND    18.0    3 1.0259 18.466
  1402 ECOND   18.0    3 1.0259 18.466     1550 MIDPNTL   345    4 1.0285 354.85
  1600 MINE     765    4 1.0400 795.60


 BUSES WITH VOLTAGE LESS THAN 0.9800:

 X------ BUS -----X AREA V(PU)  V(KV)    X------ BUS -----X AREA V(PU)  V(KV)
  1300 SERGA    230    3 0.9778 224.89
```

Figure 6.27. Sample Output from Activity VCHK Showing Buses with Voltages Outside a Tight Checking Range

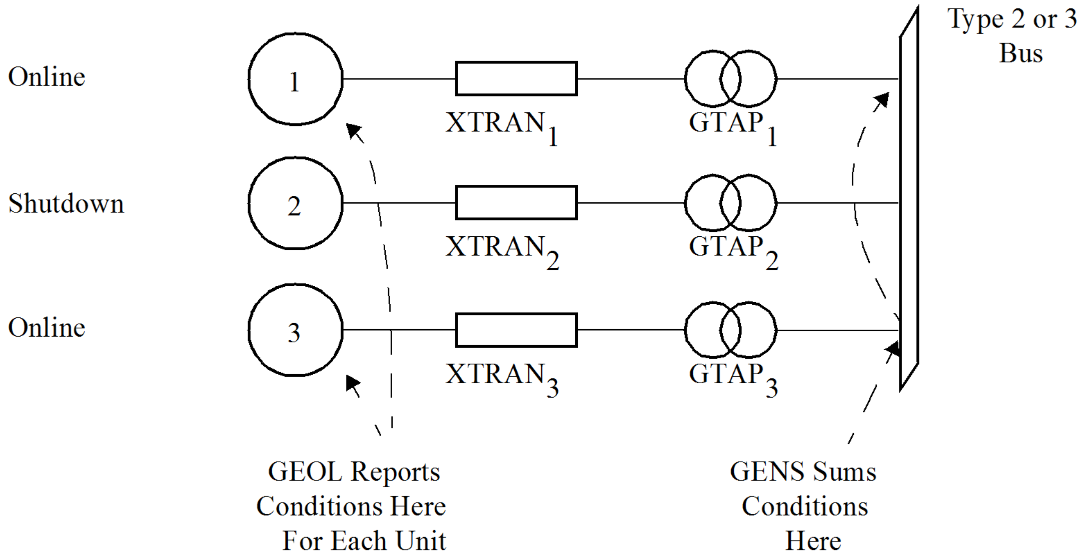
6.6.9. Activities GENS and GEOL

Activity GENS, run by selecting *Power Flow>Reports>Limit checking reports...* (*Generator bus* tab), monitors generator conditions at the plant bus and is intended to summarize *plant* generating conditions. Accordingly, its report shows the total output of all units connected at each Type 2 or Type 3 bus. Activity GEOL, run from the same menu (*Machine terminal* tab), monitors generator conditions at the terminals of each generator and is intended to summarize those conditions. The reactive power and voltage information handled by GENS and GEOL, therefore, differs when generator step-up transformers are treated as generator equipment by using the XTRAN and GENTAP data elements. The conditions monitored by GENS and GEOL are illustrated by Figure 6.29, "Monitoring of Generator Loading for GENS and GEOL"; their report formats are shown in Figure 6.30, "Generator Condition Summaries from GENS and GEOL".

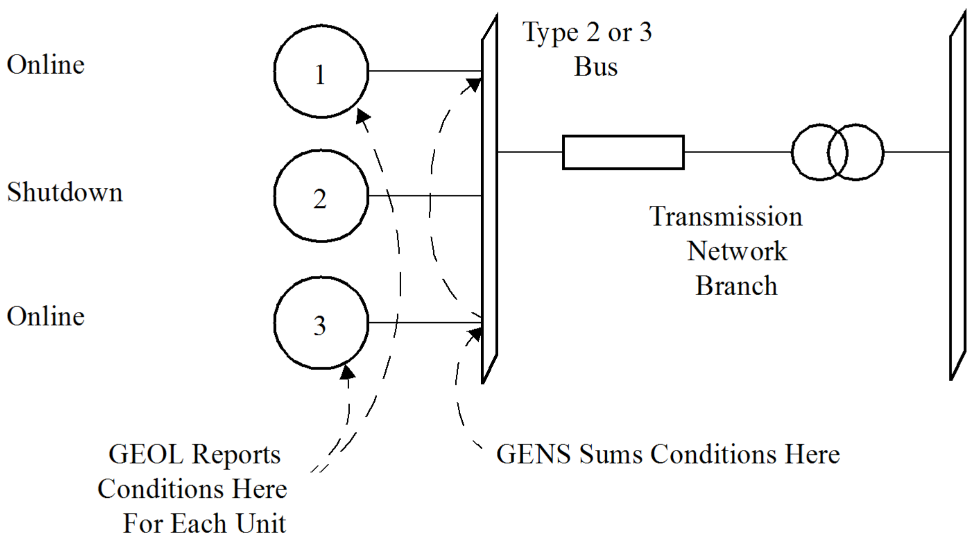



```
     PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS®E      THU, DEC 09 1999   15:12
SAMPLE SYSTEM FOR PSS®E MANUAL
1100KV DC CASE

BUSES WITH VOLTAGE GREATER THAN 1.0500:

X------ BUS -----X AREA V(PU)  V(KV)    X------ BUS -----X AREA V(PU)  V(KV)

                                  * NONE *


BUSES WITH VOLTAGE LESS THAN 0.9500:

X------ BUS -----X AREA V(PU)  V(KV)    X------ BUS -----X AREA V(PU)  V(KV)

                                  * NONE *
```

Figure 6.28. Sample Selective Output from Activity VCHK Showing No Voltages Outside Default Range

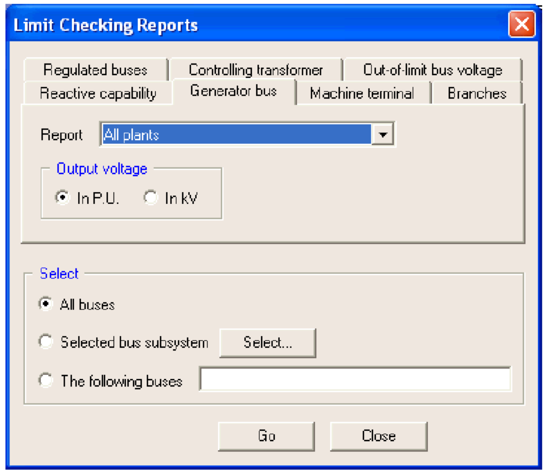


a. Step-Up Transformers Modeled with Generators



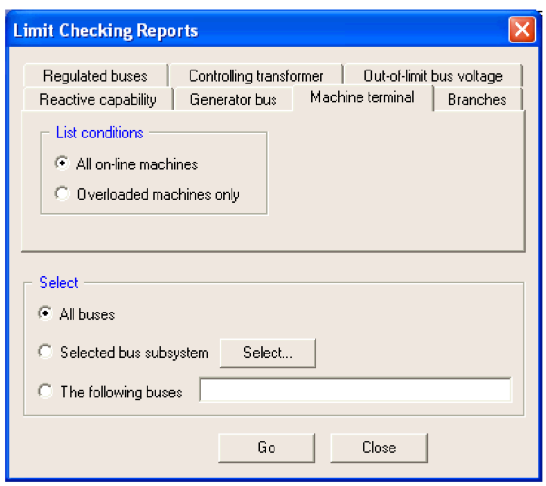
b. Step-Up Transformer Included in Transmission Network

Figure 6.29. Monitoring of Generator Loading for GENS and GEOL




```
      PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS®E      THU, DEC 09 1999  15:22
 SAMPLE SYSTEM FOR PSS®E MANUAL
 1100KV DC CASE
 GENERATOR SUMMARY:
                    # MACH
   BUS    NAME BSVLT ON/OFF TYP     MW      MVAR    QMAX    QMIN VSCHED VACTUAL  REM
   100 NUCLEAR  345  2  0    2 2000.0     11.3   800.0  -200.0 1.0400 1.0400
   200 HYDRO    345  1  0    3 1237.3   -124.7  1000.0  -300.0 1.0400 1.0400
  1100 CATNIP   230  1  0   -2  500.0    250.0   250.0     0.0 1.0200 1.0185   800
  1401 WCOND   18.0  1  0    2    0.0    653.5   800.0  -100.0 1.0000 1.0000  1403
  1402 ECOND   18.0  1  0    2    0.0    653.5   800.0  -100.0 1.0000 1.0000  1404
  1600 MINE     765  3  0    3 3000.0    835.4  2000.0 -1000.0 1.0400 1.0400
 SUBSYSTEM TOTALS              6737.3   2279.1  5650.0 -1700.0  MVABASE=    9251.0
```

a. Generator Summary Report




```
     PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS®E      THU, DEC 09 1999  15:24
 SAMPLE SYSTEM FOR PSS®E MANUAL
 1100KV DC CASE

 MACHINE SUMMARY:
   BUS    NAME BSVLT ID     MW     MVAR  ETERM CURRENT    PF   MVABASE   X T R A N   GENTAP
   100 NUCLEAR  345 1   1000.0   138.1 1.0243   985.6  0.9906  1100.0 0.0000 0.1500 1.0250
   100 NUCLEAR  345 2   1000.0   138.1 1.0243   985.6  0.9906  1100.0 0.0000 0.1500 1.0250
   200 HYDRO    345 1   1237.3   -38.8 1.0100  1225.6  0.9995  1750.0 0.0000 0.1000 1.0250
  1100 CATNIP   230 1    500.0   308.3 1.0877   540.1  0.8512   500.0 0.0000 0.1000 1.0250
  1401 WCOND   18.0 1      0.0   653.5 1.0259   637.0  0.0000   800.0
  1402 ECOND   18.0 1      0.0   653.5 1.0259   637.0  0.0000   800.0
  1600 MINE     765 1   1000.0   396.2 1.0514  1023.1  0.9297  1067.0 0.0000 0.1200 1.0250
  1600 MINE     765 2   1000.0   396.2 1.0514  1023.1  0.9297  1067.0 0.0000 0.1200 1.0250
  1600 MINE     765 3   1000.0   396.2 1.0514  1023.1  0.9297  1067.0 0.0000 0.1200 1.0250
 SUBSYSTEM TOTALS       6737.3  3041.3                          9251.0
```

Figure 6.30. Generator Condition Summaries from GENS and GEOL

b. Machine Summary Report

Activity GENS summarizes conditions at the buses to which generators are connected. If the generator step-up transformer is represented as a part of the generator by the XTRAN and GENTAP parameters, the conditions reported by GENS are those at the high-side bus. If XTRAN is not used (i.e., set to 0), the conditions reported by GENS are those at the generator terminals. GENS may be made to report on all generators or to restrict its report to generators where reactive power output is at the var bus limit. Power flow reactive power limits are always specified and checked at the bus. They are, therefore, high-side limits when XTRAN and GENTAP are used to represent the step-up transformer.

Activity GEOL summarizes conditions at the generator terminals. The generator reactive output reported by GEOL is the same as reported by GENS only when the step-up transformer is not modeled with the generator (XTRAN = 0). Hence, in Figure 6-67, GEOL shows the same conditions as GENS only for the units at buses 1401 and 1402. At bus 100, for example, GENS shows a high side reactive power output of 11.3 Mvar while GEOL shows a generator terminal reactive power output of 138.1 Mvar for each of two machines.

The generator-current column of the GEOL report is the ratio of the machine MVA output to the per-unit terminal voltage magnitude. Thus the value is available without regard to the bus base kV and may be readily calculated on either the system or machine MVA base. At bus 100:

$$\text{current} = \frac{\sqrt{(1000.0)^2 + (138.1)^2}}{1.0243} = 985.6$$

The generator terminal current is, therefore:

$$\frac{985.6}{1100} = 0.896 \text{ per unit}$$

on generator base. The transformer reactive drop, $I^2 Xt$, is:

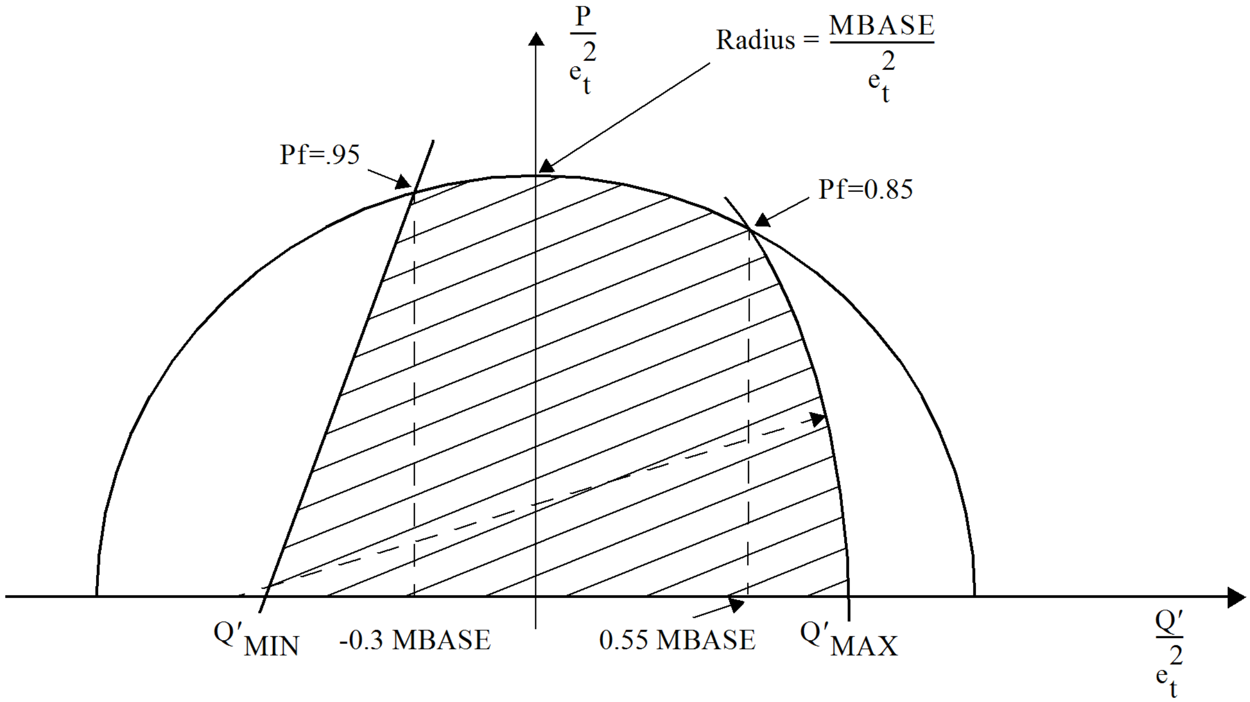
$(0.896)^2 \times 0.15$ per unit = 0.1204 per unit on generator base

$I^2X_t = 0.1204 \times 1100$ Mvar

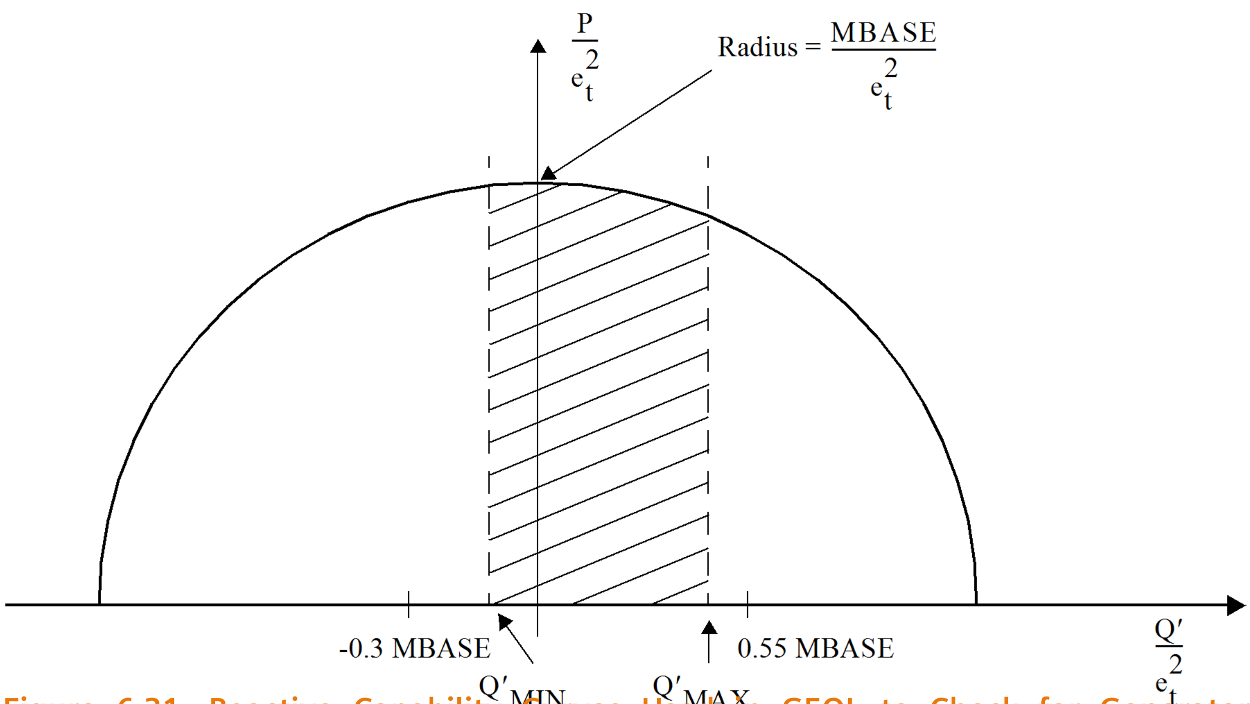
$I^2X_t = 132.46$ Mvar

Twice this value is equal to the difference between reactive power outputs reported by GEOL and GENS for this plant.

GEOL may be ordered to report on all generators in the subsystem being examined or to restrict its report to generators operating outside a representative terminal capability curve of the form shown in Figure 6.31, "Reactive Capability Curves Used in GEOL to Check for Generator Overloads". The generator's operating point is compared to a feasible operating region by transforming both to the admittance plane. The machine base is assumed to describe the armature current limit at 1.0 per unit terminal voltage. Then in the admittance plane the radius describing the active power generation limit is the ratio of MBASE/1.0 (current limit) to solved terminal voltage.



a. The var Limits Outside Power Factor Limits



b. The var Limits Inside Power Factor Limits

Figure 6.31. Reactive Capability Curves Used in GEOL to Check for Generator Overloads

Note that the Q'_{max} and Q'_{min} values appearing in Figure 6.31, "Reactive Capability Curves Used in GEOL to Check for Generator Overloads" are terminal values and hence are not the same as the power flow data values Q_{max} and Q_{min} if the step-up transformer is modeled with the generator. GEOL derives the values of Q'_{max} and Q'_{min} from the bus-side values in accordance with:

$$Q'_{limit} = Q_{limit} + \frac{x_t Q_{limit}^2 GTAP^2}{MBASE}$$

where *limit* indicates maximum or minimum.

Also, the above derivation of Q'_{max} and Q'_{min} is independent of any adjustment of var limits that the user may have made, (see Section 5.5.2.1 General Treatment), in deciding on values for the bus-side limits, Q_{max} and Q_{min}.

While the capability curves of Figure 6.31, "Reactive Capability Curves Used in GEOL to Check for Generator Overloads" are only a representative approximation, they do allow for a rough check of generator field-current loading as well as stator loading during power flow work. All generator excitations should, of course, be checked again during the setup and initialization of dynamic simulations.

6.6.10. Activities LOUT/LAMP

Activity LOUT provides power flow output in an alternative format to that produced by activity POUT and is run from the same menu selection. A sample of the LOUT format is shown in Figure 6.32, "Sample Output from Activity LOUT Alphabetical Ordering of PSS®E in Effect".

Activity LAMP, run from the same menu selection, produces a power flow report similar to LOUT except in two regards. The area number of the to bus that appears in the LOUT report is replaced in the LAMP report with the current magnitude for those branches where the from bus base kV is nonzero. On the LAMP report, the rating for nontransformer branches is provided in amperes when both the default rating and from bus base kV are nonzero. The rating for transformer branches is always provided in volt-ampere units. A sample of the LAMP report is provided in Figure 6.33, "Sample Output from Activity LAMP". All notes given for POUT in Section 6.6.3, "Activity POUT" apply to LOUT.

6.6.11. Activity SUBS

Activity SUBS, run by selecting *Power Flow>Reports>Area / owner / zone totals...*, produces a report of total load, generation, and losses for an arbitrarily specified subsystem. The subsystem may be specified by any combination of the area, zone, owner, number, or voltage level options covered in Section 6.3.1, "Report Selection and Routing ", and need not be electrically contiguous. The format of the report produced by SUBS is shown in Figure 6.34, "Sample Output from Activity SUBS". The nominal values of the load components state the load that would exist if all buses were at unity voltage. The actual of load state is the load being supplied when the bus voltages are at their solved values. Therefore, the actual loads reported by SUBS are meaningful only if the working files contain a solved power flow case.

6.6.12. Activity OLTL

Activity OLTL, same menu as RATE (see Section 6.6.7, "Activity RATE"), applies to and reports on transmission lines only. It is otherwise identical to activity RATE.

```
                                  PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS®E      THU SEP 13, 1990  13:30
                               SAMPLE SYSTEM FOR PSS®E MANUAL
                               1100KV DC CASE
 <========================= BUS DATA =========================> <=========================== LINE DATA
============================>
   FROM               AREA  VOLT            GEN      LOAD     SHUNT   TO
TRANSFORMER   RATING A
  BUS       NAME      ZONE PU/KV  ANGLE  MW/MVAR  MW/MVAR MW/MVAR  BUS       NAME      CKT AREA    MW    MVAR    RATIO
ANGLE   %I  MVA
 ===== ============ ==== ===== ====== ======= ======= ======= ===== ============ === ====  ====== ======  =======
======= === ====
  100 CATNIP   230   2  1.061  -21.3    500.0      0.0     0.0 -----------------------------------------------------
---------------
                     1  244.0         250.0H     0.0     0.0   800 SETOUN   230  1    2    250.0  125.0
53  500
                                                                800 SETOUN   230  2    2    250.0  125.0
53  500
  400 EAST     345   1  1.004  -22.5      0.0      0.0     0.0 -----------------------------------------------------
---------------
                     1  346.4             0.0      0.0     0.0  600 EASTLV   230  1    2    421.8    1.6  1.000LK
56  750
                                                               600 EASTLV   230  2    2    421.8    1.6  1.000LK
56  750
                                                                200 HYDRO    345  1    1   -430.0    1.3
5   850
                                                                200 HYDRO    345  2    1   -430.0    1.3
50  850
                                                               300 WEST     345  1    1     16.4   -5.9
2   850
  600 EASTLV   230   2  1.005  -24.9      0.0    500.0     0.0 -----------------------------------------------------
---------------
                     1  231.1             0.0      0.0     0.0  400 EAST     345  1    1   -421.8   16.0  1.000UN
56  750
                                                               400 EAST     345  2    1   -421.8   16.0  1.000UN
56  750
                                                                800 SETOUN   230  1    2     34.9  -69.4
15  500
                                                                800 SETOUN   230  2    2     34.9  -69.4
15  500
                                                                700 SWURB    230  1    2    136.8   53.4
29  500
                                                                700 SWURB    230  2    2    136.8   53.4
29  500
 1402 ECOND   18.0   3  1.026   -7.2      0.0      0.0     0.0 -----------------------------------------------------
---------------
                     2  18.47         653.5R     0.0  -105.2  1404 EDUM    18.0  1    3      0.0  758.7
7  1000
 1404 EDUM    18.0   3  1.000   -7.2      0.0      0.0     0.0 -----------------------------------------------------
---------------
                       2  18.00           0.0      0.0     0.0  1600 MINE      765 # 2   4  -1444.3  590.9  1.000RG
18 2RG INVERTER
                                                              1402 ECOND   18.0  1    3      0.0 -739.6
7  1000
```

ac system transformer tap position

Inverter margin angle, g

Rectifier delay angle, a

Converter transformer tap positions

Figure 6.32. Sample Output from Activity LOUT Alphabetical Ordering of PSS®E in Effect

Figure 6.33. Sample Output from Activity LAMP

```
     PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS®E      THU, DEC 09 1999  15:32
SAMPLE SYSTEM FOR PSS®E MANUAL
1100KV DC CASE

*****************  SUMMARY FOR THE SUBSYSTEM SPECIFIED BY  *****************

AREAS:
  1 GENSYS         3 NEWLOAD

                BASE VOLTAGE OF  345.0 KV THROUGH  765.0 KV

****************************************************************************

                            SYSTEM SWING BUS SUMMARY
  BUS X---NAME---X X--- AREA ---X X--- ZONE ---X       MW       MVAR   MVABASE
  200 HYDRO     345    1 [GENSYS  ]    1 [        ]  1237.3    -124.7    1750.0

                             AREA SLACK BUS SUMMARY
X--- AREA ---X SWING X---NAME---X X--- ZONE ---X       MW       MVAR   MVABASE
  1 [GENSYS  ]   200 HYDRO     345    1 [        ]  1237.3    -124.7    1750.0

    4 BUSES           2 PLANTS             3 MACHINES        0 LOADS
    7 BRANCHES        0 TRANSFORMERS       0 DC LINES        0 FACTS DEVICES

                       X------ ACTUAL ------X X----- NOMINAL ------X
                            MW        MVAR        MW        MVAR
FROM GENERATION           3237.3    -113.3      3237.3    -113.3
TO CONSTANT POWER LOAD       0.0       0.0         0.0       0.0
TO CONSTANT CURRENT          0.0       0.0         0.0       0.0
TO CONSTANT ADMITTANCE       0.0       0.0         0.0       0.0
TO BUS SHUNT                 0.0       0.0         0.0       0.0
TO FACTS DEVICE SHUNT        0.0       0.0         0.0       0.0
TO LINE SHUNT                0.0       0.0         0.0       0.0
FROM LINE CHARGING           0.0     923.9         0.0     884.3

 VOLTAGE       X----- LOSSES -----X   X-- LINE SHUNTS --X   CHARGING
 LEVEL BRANCHES      MW        MVAR       MW        MVAR       MVAR
 345.0       7     72.21     654.21      0.0         0.0      923.9
 TOTAL       7     72.21     654.21      0.0         0.0      923.9
```

Figure 6.34. Sample Output from Activity SUBS

6.6.13. Activity OLTR

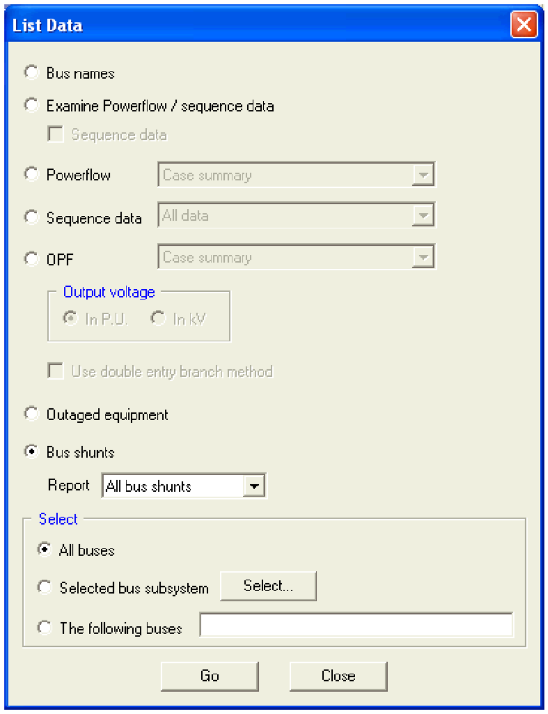
Activity OLTR, same menu as RATE and OLTL, checks for transformer overloads and produces a report of the same format (Figure 6.26, " Sample Output from Activity RATE") as RATE and OLTR. Activity OLTR differs from RATE and OLTR in that it compares the *actual MVA flow* into the transformer at each side against the designated rated MVA value. This activity, then, rates transformers on the basis of MVA, rather than on the basis of current as in activity RATE. The percentage loading is determined in OLTR as:

$$\left(\frac{MVA_{actual}}{MVA_{rated}}\right) \times 100$$

where MVA_{actual} is the greater of the MVA flows measured at the two sides of the transformer. The LOADING column displayed by OLTR shows this actual MVA loading.

6.6.14. Activity SHNT

Figure 6.35, "Activity SHNT Dialog and Output" shows the sample dialog and output for activity SHNT, a bus oriented activity, run by selecting *Power Flow>List Data... Bus shunts*. The user has the option of obtaining static shunts, switched shunts, or both. The activity lists both the nominal amount of those shunts in service and the voltage at the bus. Even those shunts created by equivalence activities will be listed. It is assumed that the user will not want a list of shunts in equivalenced subsystems and will not request those subsystems to be listed.




```
      PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS®E      THU, DEC 09 1999
15:39
 PSS®E PROGRAM APPLICATION GUIDE EXAMPLE
SHUNT
 BASE CASE INCLUDING SEQUENCE DATA
SUMMARY

                           N O M I N A L
 X------ BUS ------X         MW       MVAR   VOLTAGE
   151  NUCPANT   500       0.0     -600.0    1.0043  FIXED
   151  NUCPANT   500       0.0      -60.0    1.0043  SWITCHED
   154  DOWNTN    230       0.0      200.0    0.9154  FIXED
   201  HYDRO     500       0.0     -300.0    1.0105  FIXED
   203  EAST230   230       0.0       50.0    0.9487  FIXED
   205  SUB230    230       0.0      300.0    0.9262  FIXED
```

Figure 6.35. Activity SHNT Dialog and Output

6.6.15. Activity TLST

Activity TLST, run by selecting *Power Flow>Reports>Limit checking reports...* (*Controlling transformer* tab), tabulates only those transformers where the off-nominal turns ratio or phase-shift angle can be adjusted by the power flow solution. Alternatively, the activity can limit its listing to only those transformers outside its specific band. The report can be very useful in finding data errors.

6.6.16. Activity DIFF

Activity DIFF, run by selecting *File>Compare...* (*Powerflow Cases* tab), was designed to compare two power flow cases. The activity allows the user to compare most PSS®E input quantities and several different output quantities. Activity DIFF is helpful in documenting a new base case when several changes have been made. The activity is also extremely helpful in finding minor input changes between two cases. The output comparisons can be very useful in documenting differences in studies such as capacitor placement (compare voltages) and conductor selection (compare flows). Table 6.4, "Activity DIFF Comparison Capabilities " lists the items that can be compared.

6.6.17. Activity CMPR

While activity DIFF allows comparison of individual equipment differences, it is often desirable to run a system-wide totals comparison. Activity CMPR, run by selecting *File>Compare...* (*Case Totals* tab), tabulates generation, load, losses and mismatch for two cases and points out the differences in physical units and percent. The same totals can also be obtained on an area, owner or zone basis.

6.6.18. Activity GCAP

Activity GCAP, run by selecting *Power Flow>Reports>Limit checking reports...* (*Reactive capability* tab), allows the user to specify generator capability curves and to check machine loadings against these curves. This activity optionally will update the artificial reactive limits used in power flow calculations to those calculated by GCAP. In subsequent solutions these reactive limits may be used.

6.6.19. Activity REGB

Activity REGB, run by selecting *Power Flow>Reports>Limit checking reports...* (*Regulated buses* tab), provides a report for all in-service voltage-regulated buses that includes the regulated bus description, the regulated bus voltage magnitude in per unit and kV, the controlling element description, the voltage limits, and any violation of the controlled voltage. Only in-service controlling elements are reported. A sample report is provided in Figure 6.36, "Sample Output from Activity REGB Limited to Area 1".

Table 6.4. Activity DIFF Comparison Capabilities

Selection Code	Item	Default in Threshold Engineering Units
1	Bus identifiers	Not applicable
2	Bus codes	Not applicable
3	Machine status	Not applicable
4	Generator MW	0.0 MW
5	Generation	0.0 MW or 0.0 Mvar
6	Bus loads	0.0 MW or 0.0 Mvar
7	Bus shunts	0.0 MW or 0.0 Mvar
8	Switched shunts	0.0 MW or 0.0 Mvar
9	Voltage	0.01 per unit
10	Voltage and angle	0.01 per unit or 5 degrees
11	MBASE and ZSORCE	0.0 for all
12	MBASE and ZPOS	0.0 for all

Selection Code	Item	Default in Threshold Engineering Units
13	MBASE and ZNEG	0.0 for all
14	MBASE and ZZERO	0.0 for all
15	Negative-sequence bus shunts	0.0 per unit
16	Zero-sequence bus shunts	0.0 per unit
17	Branch status	Not applicable
18	Line *R*, *X*, β	0.0 for all
19	Line shunts	0.0 per unit
20	Line ratings	0.0 MVA
21	Metered-end	Not applicable
22	Transformers	Tap or configuration
23	Line flows (from bus)	0.0 MW or 0.0 Mvar
24	Line flows (from and to)	0.0 MW or 0.0 Mvar
25	Line losses	0.0 MW or 0.0 Mvar
26	Zero-sequence *R*, *X*, β	0.0 for all
27	Zero-sequence line shunts	0.0 for all
28	Connection codes	Not applicable
29	Zero-sequence mutuals	0.0 for all
30	Multisection lines	Not applicable
31	Multisection line, metered-end	Not applicable
32	Bus load status	Not Applicable
33	Line lengths	0.0 for all

Figure 6.36. Sample Output from Activity REGB Limited to Area 1

6.7. Power Flow Solution

6.7.1. Solution Activities

The theory of power flow solution is discussed in Chapter 5, *Power System Network Simulations*. PSS®E includes five power flow solution activities, each of which operates on the bus voltage estimates in the working file to attempt to bring them to a solution of Kirchhoff's laws. Each activity makes successive adjustments to the bus voltages in accordance with a different iterative scheme. The activities and iterative schemes are as follows:

SOLV

Gauss-Seidel Iteration

MSLV

Gauss-Seidel Iteration with modification to handle series capacitors

FNSL

Full Newton-Raphson iteration

NSOL

Decoupled Newton-Raphson iteration

FDNS

Fixed-Slope Decoupled Newton-Raphson iteration

No one of these activities is satisfactory for all power flow problems; SOLV, MSLV, and FDNS are able to handle poor starting voltage estimates such as those of a flat-start or when a major network change has been made. SOLV cannot handle negative branch reactances. MSLV can handle negative branch reactances if they are not adjacent to generator buses, but fails when negative-reactance branches terminate on generator buses. FNSL and NSOL have more rapid convergence than SOLV and MSLV, but can be troublesome if not given good starting voltage estimates. NSOL cannot handle cases having branches with a low *X*/ *R* ratio. The general characteristics of these power flow iteration schemes are summarized in Table 6.10, "Transmission Branch Parameters ".

6.7.2. Starting Voltage Estimates

Each of the five power flow iteration activities must start its calculations with an initial estimate of the voltage at each bus. The initial, or starting estimate, is always taken to be either the complex vector of bus voltages presently in the working file or a flat-start voltage vector.

The voltage vector presently in the working file might be a very good estimate of the true voltage solution. If so, it is usually a good estimate if it is the result of a previous power flow solution for a system condition that is similar to the one about to be solved. It is usually useless as a starting estimate if it is the last voltage estimate made in a previous diverging attempt to solve a power flow case. A flat-start voltage vector is obtained by using the suffix, *FS*, in invoking the power flow solution activity. The flat-start vector is obtained by setting all bus voltages as follows:

- All Type 1 bus voltages are set to $1 + j0$.

- All Type 2 and 3 bus voltages are set to $V + j0$ where V is scheduled voltage (pu).

A flat-start is often the only possibility after a power flow iteration has diverged. The decision to use a flat-start or the present content of the working file as the starting voltage estimate, in most other cases, depends upon the experience of the power flow user. As a general rule, however, it is usually worth trying a solution with the present working file content as the starting estimate. It may lead to divergence but nothing is lost in trying because it is always possible to return to a flat-start and try again. More importantly, there is often no reason to expect a flat-start to be a better estimate than the present content of the working file.

6.7.3. Convergence Monitoring

Each power flow solution activity repeats its voltage adjustment calculation over and over until it is terminated by one of the following:

- Interruption by the user (F10).
- Reduction of a convergence monitor quantity below a prespecified tolerance magnitude.
- The number of iterations reaches an upper limit.

Termination of a power flow solution activity by the user or by its internal logic implies neither that the power flow case is finished nor unfinished. The solution is finished when the user is satisfied with it, usually under either of these conditions:

- The voltage vector in the working case approximates the true voltage solution within the machine's digital work-length precision limit.
- The user decides that the mismatch at all buses is small enough in relation to present needs.

Mismatch is defined for each bus in the system as:

$(\Delta P + J \Delta Q) = S_{mismatch} = S_{gen} - S_{load} - S_{shunt} - \Sigma S_{branch}$

where S = complex power. All mismatches would be zero in a perfect power flow solution.

The convergence monitor and normal maximum iteration counts of the five power flow solution activities are summarized in Table 6.5, "Power Flow Convergence and Termination Criteria". Each power flow solution activity displays a record of its convergence progress as it operates (Figure 6.37, "Convergence Monitor Display from Activities FNSL, FDNS, and NSOL" and Figure 6.38, "Convergence Monitor Display from Activities SOLV and MSLV"). The message REACHED TOLERANCE IN *N* ITERATIONS does not indicate that the solution is finished, and the message TERMINATED AFTER *N* ITERATIONS does not indicate that the solution is unfinished. The authoritative indication of the quality of the voltage estimate vector, and hence of the power flow solution, is the largest bus complex power mismatch listed after termination of the iterative process. The solution obtained in Figure 6.37, "Convergence Monitor Display from Activities FNSL, FDNS, and NSOL" would be acceptable for virtually all purposes; the solution obtained in Figure 6.38, "Convergence Monitor Display from Activities SOLV and MSLV" with its largest mismatch of 73.25 MW and –8.46 Mvar would be unsatisfactory for precise analysis, but may still be quite satisfactory for quick estimating purposes. The mismatch at each bus is listed by activity POUT if it exceeds 0.5 MVA.

Table 6.5. Power Flow Convergence and Termination Criteria

Activity	Normal Maximum Iteration Count	Convergence Monitor Quantity
SOLV and MSLV	100	Magnitude of largest bus voltage change in the iteration

Activity	Normal Maximum Iteration Count	Convergence Monitor Quantity
FNSL, FDNS, and NSOL	20	Magnitude of largest real power mismatch and largest reactive power mismatch at any bus or buses

```
ACTIVITY? fnsl,opt

TAP CODE IS 0 TO LOCK, 1 FOR STEPPING, 2 FOR DIRECT

ENTER:
 [TAP ] , [1 FOR AREA] , [1 FOR PHSE] , [1 TO FLT] , [1 TO LOCK] , [1 TO LOCK ]
 [CODE]   [INTERCHNGE]   [SHIFTERS  ]   [START   ]   [D.C. TAPS]   [SWCH SHNTS]
1

ENTER ITERATION NUMBER FOR VAR LIMITS
 0 FOR IMMEDIATELY, -1 TO IGNORE COMPLETELY: 0

ITER    DELTAP    BUS      DELTAQ    BUS      DELTA/V/    BUS     DELTAANG    BUS
  0    20.3835(   100)     5.9092( 1401)
                                             0.16115( 1100)     0.44782(   700)
  1     3.2754(   100)     2.6613( 1401)
                                             0.09056(  300)     0.02108( 1300)
  2     0.1034( 1100)      3.8834( 1401)
                                             0.01878( 1550)     0.00266(   100)
  3     0.0206(   100)     0.1970( 1401)
                                             0.00064( 1402)     0.00009( 1550)
  4     0.0001( 1201)      0.0090( 1401)
                                             0.00003( 1402)     0.00000( 1402)
  5      0.0000( 1200)      0.0002( 1200)

REACHED TOLERANCE IN   5 ITERATIONS

LARGEST MISMATCH:      0.01 MW    -0.02 MVAR      0.02 MVA-BUS  1201 [SWIGA      230]
SYSTEM TOTAL ABSOLUTE MISMATCH:                   0.13 MVA
```

Use FNSL with options to be

Tap code choices

Option selection

Activate stepping transformer tap adjustment during solution

Convergence monitor

Iteration number

Real power mismatch per unit of system base MVA

Bus with largest real power mismatch

Reactive power mismatch per unit of system base MVA

Bus with largest reactive power mismatch

Largest voltage magnitude change

Bus at which magnitude voltage change is made

Largest voltage phase angle change, radians

Bus at which angle change is made

Largest mismatch or voltage change at any bus

Termination summary

Figure 6.37. Convergence Monitor Display from Activities FNSL, FDNS, and NSOL

```
ACTIVITY? solv,fs

ITER DELTAV/TOL  BUS    REAL(DELTAV)    IMAG(DELTAV)
   1  2666.561  1300    -0.4426E-01     -0.2630E+00
   2  1405.936  1100     0.3330E-02     -0.1406E+00
   3  1122.077   400     0.5444E-02     -0.1121E+00
   4   635.516   500    -0.2100E-01     -0.5998E-01
   5   540.962   300    -0.1684E-01     -0.5141E-01
   6   258.731   400    -0.1822E-01     -0.1837E-01
   7   208.163   300    -0.1755E-01     -0.1119E-01
   8   120.061   300    -0.1200E-01      0.2559E-03
   9    70.074  1300    -0.1817E-02     -0.6768E-02
  10    71.508  1402     0.7208E-03     -0.7114E-02
  11    59.728  1402     0.4078E-03     -0.5959E-02

  99     7.369  1404    -0.5311E-03     -0.5108E-03
 100     7.478  1404     0.4446E-03     -0.6012E-03

TERMINATED AFTER 100 ITERATIONS

LARGEST MISMATCH:    73.25 MW    -8.46 MVAR     73.74 MVA-BUS  1200 [STERML    230]
SYSTEM TOTAL ABSOLUTE MISMATCH:                185.07 MVA
```

Use flat-starting voltage estimates

Convergence monitor display

Iteration number

Number of bus getting largest voltage change this iteration

Imaginary part of largest voltage change

Largest voltage change this iteration

Voltage change tolerance

Real part of largest voltage change

Stopped on iteration count; |Δ| still 4.409 times tolerance

Figure 6.38. Convergence Monitor Display from Activities SOLV and MSLV

6.7.4. Changing Iterative Methods

In many power flow cases, the solution can be expedited by using two (or even more) iteration activities in succession in order to take advantage of the complementary strengths of the various iterative schemes. For example, if the starting voltage estimate is known to be poor, it is often advantageous to run several Gauss-Seidel iterations with SOLV or MSLV and to switch over to the Newton-Raphson iterations when the voltage estimate has been brought into rough approximation to the true solution.

Figure 6.39, "Power Flow Solution Dialog Showing Interruption of One Activity using S AB and Completion with Another Activity" shows a sample dialog following this approach. The solution was started from a flat-start estimate. It converged reasonably rapidly to the point where each iteration produced a voltage change of about 28 times tolerance on bus 1401. Activity SOLV was interrupted after 34 iterations had been reported. The mismatch after interruption was unacceptable (337.28 MVA). The solution was, therefore, to continue activity FNSL, which required only six Newton-Raphson iterations to bring the mismatch down to the very acceptable level of 0.03 MVA. Note that the starting voltage estimate for FNSL in Figure 6.39, "Power Flow Solution Dialog Showing Interruption of One Activity using S AB and Completion with Another Activity" was the last voltage vector estimated in the preceding execution of SOLV.

```
ACTIVITY? solv,fs

ITER DELTAV/TOL   BUS    REAL(DELTAV)     IMAG(DELTAV)
   1  2666.561   1300   -0.4426E-01     -0.2630E+00
   2  1405.936   1100    0.3330E-02     -0.1406E+00
   3  1122.077    400    0.5444E-02     -0.1121E+00
   4   637.408    500   -0.2148E-01     -0.6001E-01
   5   542.739    300   -0.1737E-01     -0.5142E-01
   6   273.903    400   -0.2018E-01     -0.1852E-01
   7   218.139    300   -0.1866E-01     -0.1130E-01
   8   124.796    300   -0.1248E-01      0.2365E-04
   9    89.702   1300   -0.5538E-02     -0.7057E-02
  10    67.091   1401   -0.2195E-02     -0.6340E-02
  11    66.394   1300   -0.3795E-02     -0.5448E-02
  12    57.400   1200   -0.2888E-02     -0.4961E-02
  13    57.725   1300   -0.3688E-02     -0.4441E-02
  14    52.731   1300   -0.3494E-02     -0.3950E-02
  15    52.476   1300   -0.3368E-02     -0.4024E-02
  16    48.851   1300   -0.3110E-02     -0.3767E-02
  17    47.674   1300   -0.2982E-02     -0.3720E-02
  18    45.427   1300   -0.2830E-02     -0.3554E-02
  19    43.670   1300   -0.2672E-02     -0.3454E-02
  20    41.854   1300   -0.2532E-02     -0.3333E-02
  21    40.291   1300   -0.2407E-02     -0.3231E-02
  22    38.840   1200   -0.1365E-02     -0.3636E-02
  23    37.657   1200   -0.1283E-02     -0.3540E-02
  24    36.514   1200   -0.1205E-02     -0.3447E-02
  25    35.422   1200   -0.1133E-02     -0.3356E-02
  26    34.378   1200   -0.1066E-02     -0.3268E-02
  27    33.375   1200   -0.1004E-02     -0.3183E-02
  28    32.549   1402   -0.3771E-03     -0.3233E-02
  29    31.755   1402   -0.3450E-03     -0.3157E-02
  30    30.982   1402   -0.3164E-03     -0.3082E-02
  31    30.229   1402   -0.2914E-03     -0.3009E-02
  32    29.492   1401   -0.2680E-03     -0.2937E-02
  33    28.774   1401   -0.2466E-03     -0.2867E-02
  34    28.071   1401   -0.2268E-03     -0.2798E-02

Yes? s ab
  35    27.385   1401   -0.2090E-03     -0.2731E-02

TERMINATED AFTER   35 ITERATIONS

LARGEST MISMATCH:   337.01 MW    13.40 MVAR    337.28 MVA-BUS  1200 [STERML    230]
SYSTEM TOTAL ABSOLUTE MISMATCH:                769.33 MVA

ACTIVITY? fnsl

ENTER ITERATION NUMBER FOR VAR LIMITS
 0 FOR IMMEDIATELY, -1 TO IGNORE COMPLETELY: 0

ITER    DELTAP    BUS       DELTAQ    BUS      DELTA/V/    BUS     DELTAANG    BUS
 0      3.3701( 1200)      0.1342( 1200)
                                              0.01631(  400)    0.10214( 1402)
 1      0.0477( 1200)      0.2708( 1403)
                                              0.03409( 1300)    0.01614( 1300)
 2      0.0441( 1403)      0.7020( 1403)
                                              0.09115( 1300)    0.03801( 1404)
 3      0.2351( 1300)      0.0486( 1401)
                                              0.01569( 1404)    0.01661( 1402)
 4      0.0233( 1403)      0.0280( 1403)
                                              0.00199( 1300)    0.00385( 1402)
 5      0.0017( 1403)      0.0029( 1403)
                                              0.00022( 1300)    0.00037( 1404)
 6      0.0002( 1403)      0.0004( 1200)

REACHED TOLERANCE IN    6 ITERATIONS

LARGEST MISMATCH:    -0.02 MW    -0.03 MVAR     0.03 MVA-BUS  1403 [WDUM     18.0]
SYSTEM TOTAL ABSOLUTE MISMATCH:                 0.12 MVA
```

Start from flat start with Gauss Seidel iterations

Note large initial voltage adjustments

Convergence is slow, monotonic

Hit appropriate interrupt here; cross-talk, jumbling of characters is normal on some terminals

S AB response to interrupt abandons activity

Largest |Δ| still 49 times tolerance

Very poor voltage estimate for solution, but a good start for Newton iterations

Finish with Newton iterations using last voltage estimate from SOLV as starting point

Good solution

Figure 6.39. Power Flow Solution Dialog Showing Interruption of One Activity using S AB and Completion with Another Activity

6.7.5. Power Flow Acceleration and Tolerance

Acceleration and Tolerance Data

The convergence of Gauss-Seidel power flow iterations is very dependent upon the acceleration of the voltage adjustment process. The five power flow solution activities use the acceleration factors listed in Table 6.6, “Power Flow Iteration Acceleration Factors”. Each acceleration factor is set to a default value based on general experience each time PSS®E is started up. The user should be prepared to tune these acceleration factors, particularly those used by SOLV, as experience is gained with the convergence characteristics of the particular problem.

Table 6.6. Power Flow Iteration Acceleration Factors

Activity	Iteration Type	Factors Used	Applied To
SOLV	Gauss-Seidel	ACCP ACCQ	Real part of voltage change Imaginary part of voltage change
MSLV	Modified Gauss-Seidel	ACCM ACCP ACCQ	Complex voltage change at Type 1 buses As for SOLV at Type 2 buses
FNSL , NSOL , FDNS	Newton-Raphson	ACCN	Magnitude of voltage change at Type 2 buses only

The four acceleration factors listed in Table 6.6, “Power Flow Iteration Acceleration Factors” can be changed via activity CHNG and are saved and retrieved with the power flow case by activities SAVE and CASE. The power flow working file contains two tolerance values for use in convergence checking: a voltage change threshold for SOLV and MSLV, and a mismatch tolerance for FNSL, FDNS, and NSOL. These tolerances are set to default values of 0.0001 per unit and 0.001 per unit, respectively, when PSS®E is started up. Both can be adjusted via activity CHNG and are saved and retrieved by activities SAVE and CASE.

Selection of Acceleration and Tolerance

Activity SOLV

Activity SOLV uses separate acceleration factors (ACCP, ACCQ) for the real and reactive parts of the power balance equation. Typical values are (ACCP, ACCQ) = (1.6, 1.6), but ACCP need not be equal to ACCQ. The guide to the selection of ACCP and ACCQ should be based on the voltage change. If the voltage change in each iteration is oscillating in magnitude or sign, decrease acceleration. If the voltage change in each iteration is decreasing smoothly, convergence may be improved by increasing acceleration (see Figure 6.40, “Dependence of Power Flow Convergence on Acceleration Factors”). Note that ACCP and ACCQ values less than unity are perfectly permissible and will be required to achieve convergence in some difficult cases.The acceleration factor should never be set greater than 2, and the optimum value seldom exceeds about 1.8.

The normal tolerance value for SOLV is 0.0001 per unit. This tolerance, applied to the largest voltage change in each iteration and convergence, is assumed when $|\Delta V|$ is less than this tolerance. The tolerance may be increased as far as 0.0005 per unit if only approximate power flows are needed. Reducing the tolerance as low as 0.00001 per unit is permissible to achieve reduced node mismatches, but such a small tolerance is not recommended for SOLV because the convergence of the Gauss-Seidel method becomes very slow as the voltage changes fall below about 0.0001 per unit.

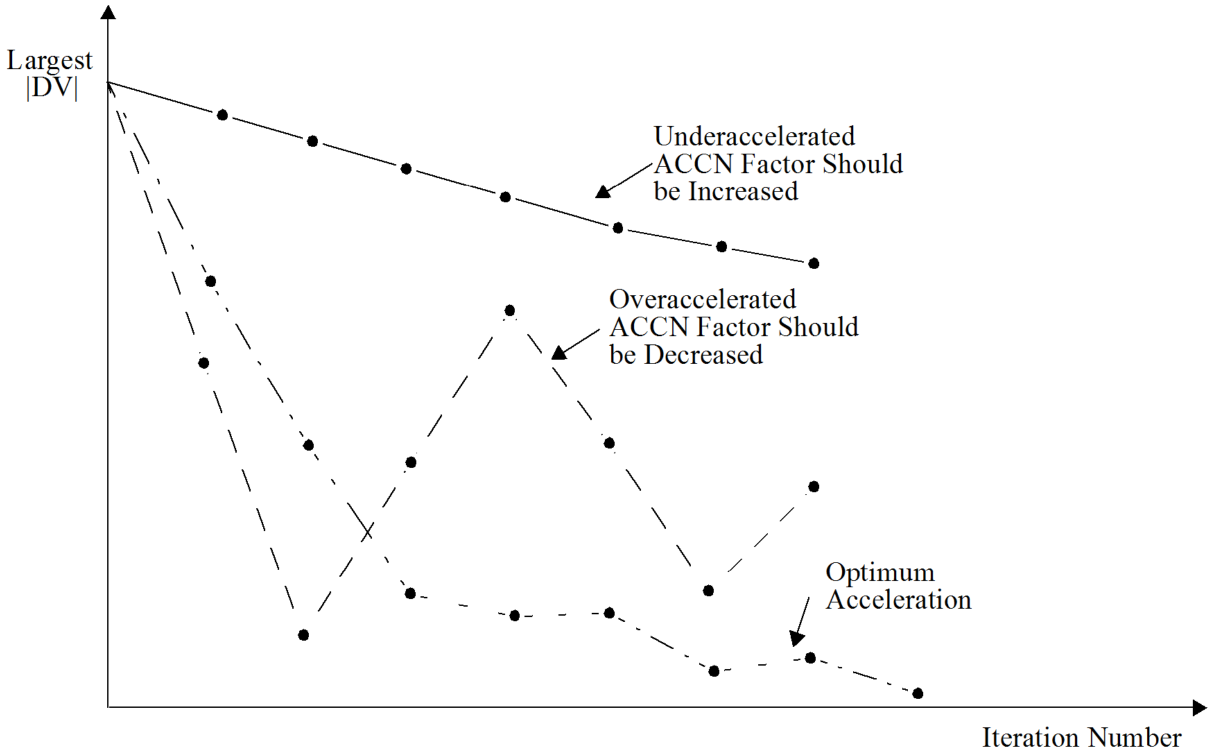


Figure 6.40. Dependence of Power Flow Convergence on Acceleration Factors

Activity MSLV

MSLV applies the standard Gauss-Seidel voltage adjustment formula at Type 2 buses and a modified formula at Type 1 buses to handle series capacitors connected between Type 1 buses. (MSLV *cannot* handle series capacitors connected to Type 2 or 3 buses.)

MSLV uses the Gauss-Seidel acceleration factors ACCP and ACCQ at Type 2 buses and a separate acceleration factor, ACCM at Type 1 buses. The principles for setting ACCM are the same as outlined above for setting ACCP, ACCQ. The convergence of MSLV is, however, very much more sensitive to the value of ACCM than is SOLV to the values of ACCP and ACCQ. Changing ACCP, ACCQ by 0.01 has very little effect on the convergence of SOLV and MSLV, but the same change in ACCM may cause a major change in the convergence properties of MSLV. Typical values for ACCM range from about 1.2 for well-behaved systems without series capacitors down to slightly below unity in difficult cases with series capacitors.

Activities NSOL, FNSL, and FDNS

NSOL, FNSL, and FDNS apply an acceleration factor to the voltage adjustments made at voltage-controlled buses. This factoring overcomes stability problems that can arise when the Newton method encounters reactive power limits. The normal value of this acceleration factor is unity, but in extremely difficult cases it can be advantageous to set its value as low as 0.5. It will never be advantageous to set this acceleration factor greater than unity.

Convergence is assumed when no real or reactive component of bus mismatch exceeds the tolerance. The typical tolerance value for Newton methods is 0.001 per unit (0.1 MW on 100-MVA base), but a tolerance as large as 0.01 per unit will give very acceptable power flow solutions for many purposes.

FNSL, FDNS, and NSOL may be unable to reduce mismatch to the 0.001 per-unit value because of the inherent computer precision limit.

Consider a branch with impedance of 0.0001 per unit and voltages close to unity at both ends. The maximum imprecision in calculation of power flow through the branch is approximately:

$$\Delta P = 2\frac{\Delta V}{Z} = 0.0025 \text{ per unit}$$

Because the bus mismatch imprecision is the sum of the imprecisions in flows into connected branches, a power flow case including such low-impedance branches is unlikely to reach the default tolerance of 0.001 per unit.

Branch impedances as low as 0.0001 per unit do not occur frequently, but can arise in star-equivalents of three-winding transformers and are sometimes used to represent jumpers between bus sections. When these low-impedance branches are found in a power flow case (by activity BRCH), it is often advisable to either raise the zero-impedance branch threshold (by activity CHNG) to represent these branches as zero-impedance lines and then remove the low-impedance branches with activity JOIN (See Section 7.9.5, "Activity JOIN"), or increase the tolerance for FNSL, FDNS, and NSOL to 0.0025 or 0.005 per unit.

A tolerance of 0.005 per unit on a 100-MVA system base represents a power flow solution imprecision of 0.5 MW, which is more than acceptable for the great majority of power flow cases.

6.7.6. Automatic Power Flow Adjustments

Invocation

Automatic adjustment options may be used in power flow solutions to allow maneuvering of the system to meet specified voltage, branch flow, and area net interchange schedules. Automatic adjustments are invoked by either setting the appropriate options with OPTN or by using the suffix OPT with activities SOLV, MSLV, FNSL, FDNS, or NSOL. The automatic adjustments available are specified in Table 6.7, "Automatic Power Flow Adjustments". When OPT for the solution activity is specified, these adjustments can be overwritten by typing in the appropriate value. In addition to the options listed in Table 6.7, "Automatic Power Flow Adjustments", the OPT suffix allows the user to start the power flow solution from a flat-start.

When enabled, an adjustment option is applied throughout the entire power flow case. Adjustment of any individual tap-changing transformer, phase shifter, or area net interchange can be suppressed by using activity CHNG to set its adjustment parameters in such a way that no adjustment can occur.

Figure 6.41, "Power Flow Solution in which Automatic Adjustment Logic Alters Transformer Tap and Phase-Shifter Positions" and Figure 6.42, "Power Flow Solution in which Automatic Adjustment Moves Power Production from Area 1 to Area 2 to Maintain Net Interchange Schedules" show examples of power flow solution using automatic adjustment options. Figure 6.41, "Power Flow Solution in which Automatic Adjustment Logic Alters Transformer Tap and Phase-Shifter Positions" shows a power flow solution from a flat-start by activity FNSL with stepping tap ratio and phase-shift angle adjustments enabled. The first adjustment takes place after two iterations; the phase shifter in branch 202-203 is moved from a setting of 0 degrees to a new setting of 2.3892 degrees; it is adjusted to a final angle of 2.127 degrees after the tenth iteration. The transformer turns ratio is adjusted after iterations 3, 7, 10, and 12. Figure 6.42, "Power Flow Solution in which Automatic Adjustment Moves Power Production from Area 1 to Area 2 to Maintain Net Interchange Schedules" shows solution of the same power flow case with only the net interchange adjustment enabled.

In this case, the absence of flow control on the phase shifter branch 202-203 requires an adjustment of the area swing generators in areas 1 and 2 to keep net interchange on schedule.

Table 6.7. Automatic Power Flow Adjustments

Type of Adjustment	Dialog Abbreviation	Available In
Adjustment of transformer turns ratio in steps to hold voltage at a designated bus in specified band.	TAPS (Normally disabled) [a]	SOLV, MSLV, FNSL, NSOL, FDNS
Direct adjustment of transformer turns ratio to hold voltage at a designated bus in specified band or to hold reactive power through transformer within specified band.	TAPS (Normally disabled)*	FNSL, NSOL, FDNS
Adjustment of area swing bus generator powers to hold area net interchange within specified band, using tie lines only or tie lines and loads.	AREA INTERCHANGE (Normally disabled)*	SOLV, MSLV, FNSL, NSOL, FDNS
Adjustment of transformer phase shift to hold real power through transformer within specified band.	PHASE SHIFTERS (Normally disabled)*	FNSL, NSOL, FDNS
Adjustment of converter transformers of dc transmission terminals to place rectifier delay angle and inverter margin angle within specified ranges.	dc TAPS (Normally enabled)*	SOLV, MSLV, FNSL, NSOL, FDNS
Adjustment of switched shunt admittances to hold voltage at the bus as close to specified voltage as permitted by inductance/capacitor module size.	SWCH SHUNTS (Normally enabled)*	SOLV, MSLV, FNSL, NSOL, FDNS
The convention regarding the definition of transformer tap ratio and phase shift is shown in *PSS®E Program Operation Manual* Figure 11-5.		

[a] PTI default.

```
ACTIVITY? fnsl,opt                                              Enable options in Newton
                                                                solution
TAP CODE IS 0 TO LOCK, 1 FOR STEPPING, 2 FOR DIRECT

ENTER:
 [TAP ] , [1 FOR AREA] , [1 FOR PHSE] , [1 TO FLT] , [1 TO LOCK] , [1 TO LOCK ]
 [CODE]   [INTERCHNGE]   [SHIFTERS  ]   [START   ]   [D.C. TAPS]   [SWCH SHNTS]
1 0 1 1                                                         Automatic tap and phase
                                                                shift adjustment, flat start
ENTER ITERATION NUMBER FOR VAR LIMITS                           Apply VAR limits at
 0 FOR IMMEDIATELY, -1 TO IGNORE COMPLETELY:                    program default

ITER   DELTAP   BUS     DELTAQ   BUS      DELTA/V/   BUS   DELTAANG   BUS
  0   12.0000(  205)   7.1856(  152)    0.06158(  152)   0.29694(  101)
  1    0.5913(  151)   2.2216(  206)    0.02092(  206)   0.02421(  101)
  2    0.0821(  201)   1.8362(  206)    0.01834(  206)   0.00280(  201)

PHASE SHIFTERS ADJUSTED

X-- TAPPED  SIDE --X  X- IMPEDANCE SIDE -X CKT    OLD        NEW       CHANGE   Phase shift changed
  202 [EAST500  500]    203 [EAST230  230]  1     0.000      2.389      2.3892  to control flow

   1 PHASE SHIFTERS ADJUSTED

  3    0.0009(  154)    0.1664(  202)     0.00097(  202)   0.00013(  206)

TAP RATIOS ADJUSTED

X-- TAPPED  SIDE --X  X- IMPEDANCE SIDE -X CKT    OLD       NEW       CHANGE   Turns ratio changed to
  152 [MID500   500]    153 [MID230   230]  1  1.01000   1.00000   -0.01000  control voltage
  204 [SUB500   500]    205 [SUB230   230]  1  1.01000   1.00375   -0.00625

   2 TAP RATIOS ADJUSTED

  4    0.0721(  152)    2.1763(  152)     0.03045( 3008)   0.00600(  101)
  5    0.0686(  205)    2.2709(  205)     0.03957(  205)   0.00738(  101)
  6    0.0405(  205)    0.0981(  205)     0.00507(  205)   0.00131(  101)

PHASE SHIFTERS ADJUSTED

X-- TAPPED  SIDE --X  X- IMPEDANCE SIDE -X CKT    OLD        NEW       CHANGE
  202 [EAST500  500]    203 [EAST230  230]  1     2.389      2.553      0.1637

   1 PHASE SHIFTERS ADJUSTED

  7    0.0000(  205)    0.0104(  202)     0.00033(  204)   0.00007(  101)

TAP RATIOS ADJUSTED

X-- TAPPED  SIDE --X  X- IMPEDANCE SIDE -X CKT    OLD       NEW       CHANGE
  152 [MID500   500]    153 [MID230   230]  1  1.00000   0.95000LO -0.05000
  204 [SUB500   500]    205 [SUB230   230]  1  1.00375   0.96625   -0.03750

   2 TAP RATIOS ADJUSTED

  8    0.3828(  152)   11.3381(  152)     0.07128(  153)   0.01120(  101)
  9    0.1204(  154)    0.8065(  153)     0.02690(  154)   0.00773(  101)
 10    0.0268(  205)    0.0191(  153)     0.00177(  154)   0.00058(  101)

TAP RATIOS ADJUSTED

X-- TAPPED  SIDE --X  X- IMPEDANCE SIDE -X CKT    OLD       NEW       CHANGE
  204 [SUB500   500]    205 [SUB230   230]  1  0.96625   0.95375   -0.01250

   1 TAP RATIOS ADJUSTED

PHASE SHIFTERS ADJUSTED

X-- TAPPED  SIDE --X  X- IMPEDANCE SIDE -X CKT    OLD        NEW       CHANGE
  202 [EAST500  500]    203 [EAST230  230]  1     2.553      2.127     -0.4260

   1 PHASE SHIFTERS ADJUSTED

 11    0.0000(  154)    1.2924(  204)     0.00596(  205)   0.00100(  206)
 12    0.0008(  154)    0.0078(  205)     0.00070(  205)   0.00017(  101)

TAP RATIOS ADJUSTED

X-- TAPPED  SIDE --X  X- IMPEDANCE SIDE -X CKT    OLD       NEW       CHANGE
  204 [SUB500   500]    205 [SUB230   230]  1  0.95375   0.95000LO -0.00375

   1 TAP RATIOS ADJUSTED

 13    0.0246(  204)    0.3976(  204)     0.00209(  204)   0.00027(  204)
 14    0.0000(  154)    0.0008(  204)

REACHED TOLERANCE IN  14 ITERATIONS                        Good solution

LARGEST MISMATCH:    0.00 MW   [illegible] MVAR   [illegible] MVA-BUS   204 [SUB500   500]
SYSTEM TOTAL ABSOLUTE MISMATCH:                 0.18 MVA
```

Figure 6.41. Power Flow Solution in which Automatic Adjustment Logic Alters Transformer Tap and Phase-Shifter Positions

```
ACTIVITY? fnsl,opt                          Enable Newton solution with options

TAP CODE IS 0 TO LOCK, 1 FOR STEPPING, 2 FOR DIRECT

ENTER:
 [TAP ] , [1 FOR AREA] , [1 FOR PHSE] , [1 TO FLT] , [1 TO LOCK] , [1 TO LOCK ]
 [CODE]   [INTERCHNGE]   [SHIFTERS  ]   [START   ]   [D.C. TAPS]   [SWCH SHNTS]  Select net interchange
0 1                                                                               control

ENTER ITERATION NUMBER FOR VAR LIMITS                                           Allow program judgment
 0 FOR IMMEDIATELY, -1 TO IGNORE COMPLETELY: 0                                  on VAR limits

ITER   DELTAP   BUS      DELTAQ   BUS      DELTA/V/    BUS    DELTAANG    BUS
  0    0.0000(  205)     0.0001(  153)
                                            0.00000(  154)    0.00000(  101)

AREA SWINGS ADJUSTED

X-- AREA --X X---- SLACK BUS----X    OLD P    NEW P    CHANGE    Area swings adjusted to bring area 1
  1 FLAPCO      101 [NUC-A    21.6]  750.00   718.75   -31.25    and area 2 net interchange onto schedule
  2 LIGHTCO     206 [URBGEN       ]  800.00   823.90    23.90
  5 WORLD      3001 [MINE         ]  248.75     SYSTEM SWING

  2 AREA SWING POWERS ADJUSTED

  1    0.3125(  101)     0.0001(  151)
                                            0.00409(  154)    0.01089(  101)
  2    0.0015(  206)     0.0010(  151)
                                            0.00012(  205)    0.00007(  101)
  3    0.0000(  154)     0.0001(  154)

                                                              Good solution
REACHED TOLERANCE IN   3 ITERATIONS

LARGEST MISMATCH:     0.00 MW     0.01 MVAR     0.01 MVA-BUS    151 [NUCPANT   500]
SYSTEM TOTAL ABSOLUTE MISMATCH:                 0.04 MVA
```

Figure 6.42. Power Flow Solution in which Automatic Adjustment Moves Power Production from Area 1 to Area 2 to Maintain Net Interchange Schedules

Adjustment Criteria

Transformer Off-Nominal Taps Ratio

Depending on the solution technique chosen, transformer tap ratio adjustments can be made to control either voltage at a specified bus, a compensated voltage based on the transformer loading or to control Mvar flow at the tapped side of the transformer (See Table 6.8, “Transformer Tap Adjustment Options”). Compensated voltage is used often on radial circuits when the user wishes to remotely regulate a voltage but does not wish to install any communication links. Note that by controlling voltage using the Newton solution activities, the user may choose one of two adjustment techniques: discrete and direct tap adjustment. The Mvar control can only be run using direct tap adjustment in FNSL, FDNS, and NSOL and is not available in SOLV and MSLV.

Table 6.8. Transformer Tap Adjustment Options

Activity	Method	Availability of Voltage Control Adjustment	Availability of Voltage Control Via Direct Tap Adjustment	Availability of Mvar Control Via Direct Tap Adjustment
SOLV	Gauss-Seidel	Yes	No	No [a]
MSLV	Modified Gauss-Seidel	Yes	No	No*
FNSL	Full Newton-Raphson	Yes	Yes	Yes

Activity	Method	Availability of Voltage Control Adjustment	Availability of Voltage Control Via Direct Tap Adjustment	Availability of Mvar Control Via Direct Tap Adjustment
NSOL	Decoupled Newton-Raphson	Yes	Yes	Yes
FDNS	Fixed-slope, decoupled Newton-Raphson	Yes	Yes	Yes

[a]Tap is assumed fixed.

With all solution activities, the request to adjust taps ratio automatically will not be honored until the voltage change is less than the adjustment threshold, ADJTR a solution parameter with a default value of 0.005 per unit. With discrete tap adjustment, tap ratio will then be adjusted to a maximum of value of tap limit, TALIM a solution parameter with a default value of 0.05 per unit until tolerance is reached. With direct tap adjustment controlling voltage, tap ratio will be adjusted, as if the taps are continuous, from the iteration when tolerance is first reached through subsequent iterations until the tolerance is again reached. At that time, unless the tap ratio is zero, all taps will be set to the nearest step, locked, and additional iterations made to bring mismatch down to tolerance once again. Similarly, with direct tap adjustment controlling Mvar, adjustment will not be made until tolerance is reached and controlling logic is identical thereafter to that of direct tap adjustment controlling voltage.

Voltage Control

Voltage control by transformer turns ratio adjustments, as described above, will only be made on transformers having the following conditions: a nonzero regulated bus number, IREG; a value of 1 for the transformer enable flag, RF. The tap ratio of each transformer is adjusted to hold a voltage magnitude between the limits VMIN to VMAX. The voltage magnitude to be controlled is calculated as follows:

$V_C = |V_{IREG} - I_{transformer} \times (CR + jCX)|$

where:

CR + jCX

Compensating impedances input by the user.

Itransformer

Current in the transformer calculated on the IREG side of the transformer.

The recommended method for suppressing ratio adjustment is to set the transformer control flag to zero. Ratio adjustment may also be suppressed by either setting IREG to 0.

The tap-step ratio should be properly coordinated with the acceptable voltage band (VMAX-VMIN) because the discrete steps of available tap ratio are recognized. The default tap-step ratio is 0.00625 per unit (0.625%). The band between VMAX and VMIN should normally be twice the transformer tap-step. A band of 2% is recommended for the normal case of 0.625% tap ratio steps. A value of 0 for tap-step should only be used to indicate continuously adjustable taps to the direct tap adjustment algorithm.

Mvar Controlling

The tap ratio is adjusted to hold the Mvar on the tap side of the transformer between the limits VMIN-VMAX. As mentioned previously for voltage-controlling transformers, the user should coordinate tap-step and available range for Mvar-controlling transformers.

Phase-Shifter Adjustment

The phase-shift angle of each phase shifter is adjusted, as necessary, to keep the real power flow through the phase shifter between the limits VMAX and VMIN.

Phase-shift adjustment is continuous and all adjustable phase shifters are adjusted simultaneously whenever the regulated real power flow of at least one of them falls outside its scheduled band. An unduly narrow band can cause nonconvergence of the power flow solution. A reasonable band is ± 5 MW of the target flow.

Net Interchange Adjustment

Each area of the power system may have one of its generators designated as an area-slack machine. Net interchange adjustment is implemented by manipulating the real power output of all area slack machines except those in areas containing system swing (Type 3) buses. Area slack machine adjustment may be suppressed for any individual area by setting the area slack bus number in the area interchange data category to 0. Area slack adjustment is continuous, but takes place only if the area net interchange falls outside the band for at least one area: (Scheduled interchange ± Interchange tolerance). An unduly small interchange tolerance can cause nonconvergence of the power flow solution.

The net interchange tolerance should be related to system interchange capability and system impedances. A typical tolerance for a large electric utility with capability for a 500 MW net interchange might be 10 MW, while an industrial plant with a maximum net interchange capability of 15 MW might be assigned a tolerance of 0.5 MW. The tolerance should be set in relation to interchange capability and remain fixed as the interchange schedule is varied.

Direct Current (dc) Converter Transformer Adjustment

A dc converter transformer is normally adjusted according to the rules in the section called “Direct Current Control”.The ac solution options can be modified such that the adjustment of converter transformer ratios are *disabled*. This disabling applies to all dc transmission lines. Selective locking of dc converter transformer taps requires that their adjustment not be disabled via the ac solution options. The tap ratio of any individual converter transformer can be locked by using the program’s data editing functions to set the dc converter tap limits and tap ratio equal to the desired value.

Switched Shunt Admittance Adjustment

Automatically switched shunt devices are normally adjusted according to the rules given in the section called “Automatically Switched Shunt Devices”. This adjustment is normally enabled in all power flow solutions. It can be suppressed, regardless of the values of MODSW for the individual switched shunt buses, by invoking the disabling option via the activity suffix, OPT. Selective locking of automatically switched shunt devices must be handled by leaving the adjustment feature *enabled* in the power flow solution activities and setting MODSW to 0 at buses where locking is required.

6.8. Saved Cases and Snapshots

The working case of PSS®E comprises a set of working files and is operated on by PSS®E activities. It is volatile and can be destroyed by an improper activity selection, accidental incorrect command, or machine failure. It is prudent, therefore, to record each new or modified system model as soon as possible after new construction has been entered. Use one of those activities listed in Section 6.1, "Construction and Changes" to record the data in a saved case file or snapshot file if dynamics data is involved. It is also advisable to make similar saved case and snapshot recordings as soon as possible after making any significant number of parameter value changes.

All ac power flow solutions are iterative processes and can diverge in such a way as to leave meaningless bus voltage estimates in the working case. It is very often desirable, therefore, to record the initial estimated condition of the power system model in a saved case before executing a power flow solution where the convergence is in doubt. It is always possible to discard a saved case or snapshot file that was made as a precaution. It is often impossible to return the working case to its prior undamaged condition after an erroneous activity command, an iteration divergence, or a computer failure.

6.9. System Model Setup

6.9.1. Bus Type Codes

The user must assign a type code to every bus in the network model. The type code follows the bus number in the bus data record and should always be specified. This type code informs the PSS®E program of the form of boundary condition to be applied in network solutions (see Table 6.9, "Bus Type Codes ").

PSS®E changes bus type codes 2 and 3 to 6 and 7, respectively, at certain stages of the equivalent construction process. Codes 6 and 7 serve internal logic purposes only and should not be changed by the user (see Chapter 8, *Equivalents*).

6.9.2. Load Data

The input functions of PSS®E allow the user the following components of load at each bus:

PL

Real power, constant MVA load.

QL

Reactive power, constant MVA load.

IP

Real power, constant current load.

IQ

Reactive power, constant current load.

YP

Real power, constant admittance load.

YQ

Reactive power, constant admittance load.

Table 6.9. Bus Type Codes

Bus Type	Description
Type 1	Load bus. No generator connected, a disconnected generator may be located at the bus. Voltage control available only by transformers, generators at other buses, or static shunt device switching. (Boundary conditions as defined in Sections the section called "Constant MVA", the section called "Constant Current", the section called "Constant Impedance", and the section called "Composite Load".)
Type 2	Generator bus. Generator is both present and connected. Voltage may be controlled by the connected

Bus Type	Description
	generator. (Boundary conditions as defined in Section Section 5.5.2, “Generator Power Flow Boundary Conditions ”.)
Type 3	Swing bus. Voltage fixed in magnitude and phase. Generator must be present and is assumed to be connected. (Boundary conditions as defined in the section called “Swing Bus”.)
Type 4	Isolated bus. Present in system model but with all branches terminating on it out of service and no generator connected. Type 4 buses are ignored in all solutions, output, and area or zone totalizations.
Type 5	Same as Type 1, but located on the boundary of an area for which an equivalent is to be constructed. Type 5 buses are retained by the equivalent construction process while Type 1 buses are deleted. (See Chapter 8, *Equivalents*.)

All of these components are specified in MW and Mvar. The MW and Mvar values for the constant current and constant admittance components are the values that would be consumed by these loads when the bus voltage is unity per unit. The many data-changing functions allow the data to be changed and the load taken out of service (see Chapter 7, *System Manipulation and Monitoring*).

6.9.3. Shunt Devices

Manually Controlled Shunt Devices

Manually controlled shunt-connected static capacitors and reactors should be entered as bus-connected constant admittance by assigning nonzero values to the GSHUNT and BSHUNT entries for the buses at which they are connected. The values of GSHUNT and BSHUNT must be set equal to the MW or Mvar that will be supplied or consumed at rated voltage, that is, to base MVA times per-unit admittance. For example, an 80-Mvar static capacitor would be specified by entering BSHUNT = +80.0 on a bus data record. A 150-Mvar shunt reactor would be specified by entering BSHUNT = −150.0 on a bus data record.

Care is needed in distinguishing between shunt devices, particularly reactors, which may be connected adjacent to a bus, but on the line side of the circuit breakers rather than on the bus side. It is best to exclude line-connected reactors from the bus constant admittance load and to specify them via transmission line data as described in Section 6.9.4, “Transmission Branches ”.

It is preferable to reserve the bus-connected shunt device data entries, GSHUNT and BSHUNT, for representation of substation devices, and not to use them to specify constant admittance load. Constant admittance load should be handled as a component of the reference load at the bus, as covered in Section 6.9.2, “Load Data” and Section 7.7, “Load Voltage Characteristics”.

Automatically Switched Shunt Devices

In addition to the manually controlled shunt devices, an automatically switched shunt voltage control subsystem may be assigned at any bus. Its general arrangement is shown in Figure 6.43, “Switched Shunt Reactors and Capacitors for Reactive Supply to Control Bus Voltage”. The subsystem may consist of up to eight blocks of reactive equipment, with each block divided into as many as nine steps.

While automatically switched shunt subsystems may be set up at any bus, they are recognized as being in service only at Type 1 buses and fixed generator output Type 2 buses; that is, switched shunts are assumed fixed at a value of BINIT at voltage-controlling Type 2 and 3 buses.

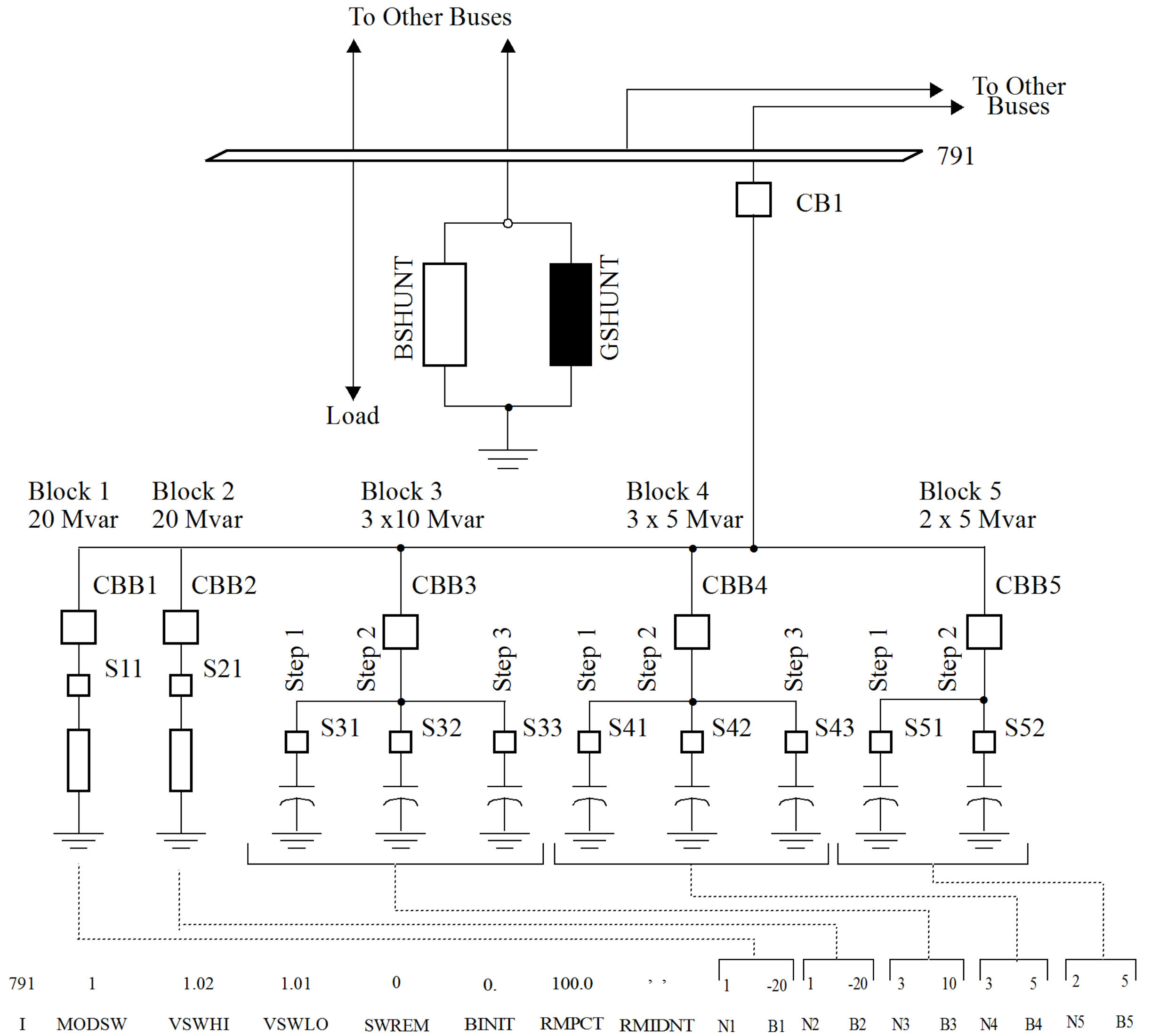


Figure 6.43. Switched Shunt Reactors and Capacitors for Reactive Supply to Control Bus Voltage

A switched shunt subsystem may include both reactors and capacitors, but reactors and capacitors may not be included in the same block. Reactor blocks, if present, must all be specified in the first block or blocks in the order in which they are to be switched on; capacitor blocks, if present, follow the reactor blocks in the order in which they are to be switched on. The subsystem is specified by:

I

Bus number.

MODSW

0 to lock all switches in present position.

1 for automatic switching (discrete).

2 to adjust reactive power continuously within full range covered by switched units.

3 for automatic switching, controlling reactive power output of the plant at bus SWREM.

4 for automatic switching, controlling reactive power output of the converter at bus SWREM of the specified VSC dc line.

5 for automatic switching, controlling admittance setting of switched shunt at bus SWREM.

VSWHI, VSWLO

Desired bus voltage range (pu) if MODSW is 1 or 2.

Desired reactive power range (pu) if MODSW is 3, 4 or 5.

SWREM

Remote Type 1 bus to be regulated.

RMPCT

Percent of the total Mvar required to hold the voltage at the bus controlled by bus I that are to be contributed by this switched shunt.

RMIDNT

When MODSW is 4, the name of the VSC dc line at converter bus SWREM.

BINIT

Initial shunt admittance, Mvar (must correspond to a legitimate combination of switch positions).

N1

Number of steps in Block 1.

B1...N8

Mvar (nominal) of each step in Blocks 1 through 8 (negative for inductive).

B8

Number of steps in Block 8.

The initial switch positions for each power flow solution are determined by the value of BINIT. The switches are set at the start of each solution activity (and in activities READ and Reading Power Flow Data Additions from the Terminal) to produce the net switched shunt admittance most closely approximating the present value of BINIT. After being set to their initial position, the switches may be frozen there by setting MODSW to 0, or placed under automatic control by setting MODSW to 1.

When MODSW is set to 1, the switched shunt steps are turned on and off to hold the bus voltage between VSWHI and VSWLO. The switching of shunt steps follows these rules:

1. The reactor and capacitor elements may not be on at the same time. Hence, if voltage is high, all capacitor steps will be switched off before reactors are switched on and vice versa.
2. Switching occurs within only one block at a time, and the elements in the block must be either all on, or all off, for switching to occur in another block.
3. In capacitor blocks, the steps of the lowest numbered block that are not yet on are switched on first, and vice versa.
4. In inductor blocks, the steps of the lowest numbered block that are not yet on are switched on first, and vice versa.

On reaching a solution, the total inductive or capacitive admittance of the steps that are on is placed in BINIT and is, therefore, the basis for the initial switch positions in the next solution.

The switched control of the shunt subsystem can be overridden to give an infinitely variable shunt inductance by setting MODSW to 2. In this case, the effective shunt admittance is varied as required, but within the overall range limits of the shunt subsystem, to hold bus voltage at mid-range between VSWHI and VSWLO. In this case, the value of admittance needed to hold voltage at this midpoint is placed in BINIT by the power flow solution activities. This value of BINIT, again, serves as the basis for setting initial switch positions if MODSW is changed back to 0 or 1.

Setting MODSW to 2 is useful where there is no prior basis on which to judge an appropriate size of capacitor or inductor step. It is also a convenient way to estimate the amount of reactive power injection needed to achieve a given voltage correction at a bus. This is facilitated by setting:

I

= bus number

MODSW

= 2

BINIT

= 0

N1

= 1

B1

= -9999

N2

= 1

B2

= 9999

6.9.4. Transmission Branches

General Branch Model

All transmission network branches are modeled in PSS®E by the general equivalent branch shown in Figure 6.44, "PSS®E Transmission Branch Equivalent Pi Model". The parameters of this model are summarized in Table 6.10, "Transmission Branch Parameters ". Transmission lines, transformers, series capacitors, bus section (series) reactors, and isolated phase branches are modeled by the appropriate specification of zero and nonzero values of the general branch parameters. All line parameters except angles and ratings are specified per unit.

Branch Ratings

Up to three ratings may be specified (in MVA) for each transmission branch. They may, for example, be set to summer continuous, winter continuous, and emergency ratings. The branch ratings are used by activities RATE, OLTL,OLTR, and DRAW to locate and report on overloads. All branch overload checks except that of activity OLTR are made on the assumption that the branch rating was determined from:

$MVA_{rated} = \sqrt{3} \times E_{base} \times I_{rated}$

where:

E_{base} = Base voltage of the bus connected to the terminal branch.

$I_{rated\ amps}$ = Rated phase current, A.

Overload checks in activities RATE, OLTL, and DRAW are made by comparing per unit current flowing into the branch at a terminal with an *implied per-unit current rating*, obtained as follows:

$$I_{rated\ per\ unit} = \frac{I_{rated\ amps}}{I_{base\ amps}} = \frac{MVA_{rated}}{\sqrt{3}E_{base}} \times \frac{\sqrt{3}\,E_{base}}{MVA_{systembase}} = \frac{MVA_{rated}}{MVA_{systembase}}$$

The transformer overload checking activity OLTR assumes that transformer ratings are entered as MVA ratings. OLTR makes its overload checks by comparing transformer MVA flow directly with the MVA rating.

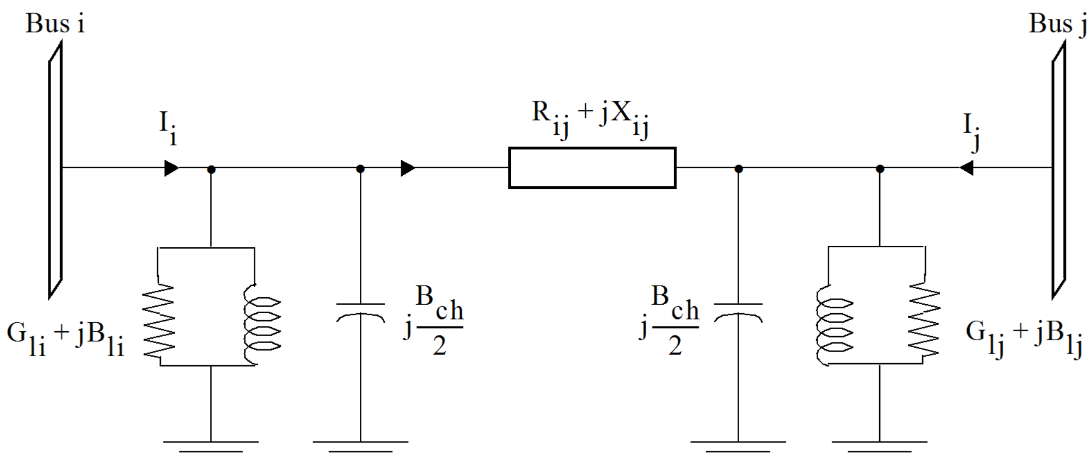


Figure 6.44. PSS®E Transmission Branch Equivalent Pi Model

Table 6.10. Transmission Branch Parameters

Parameter	Unit	Treatment if No Value in Raw Data Record
$R_{ij} + jX_{ij}$	Per-unit impedance	$R_{ij} + jX_{ij}$ = 0. + THRSHZ [a] Branch is a jumper.
B_{ch}	Per-unit admittance	Set to 0.
$G_{Ii} + jB_{Ii}$	Per-unit admittance	Set to $0 + j0$.
$G_{Ij} + jB_{Ij}$	Per-unit admittance	Set to $0 + j0$.
RATEA	MVA	Set to 0.
RATEB	MVA	Set to 0.
RATEC	MVA	Set to 0.

[a]See the section called "Zero-Impedance Branches".

Example

A transmission line between two 230-kV buses has a rated current of 1130 A. System base is 100 MVA. The rating to be entered in power flow data is:

$MVA_{rated} = \sqrt{3} \times (230 \times 10^3) \times 1130 \times 10^{-6} = 450$ MVA

A power flow solution reveals a voltage at the sending-end bus of 0.95 per unit, and a flow into the line of 445 MVA. OLTR would indicate an overloaded line relative to the 450-MVA rating because:

- Implied per-unit current rating: 450/100 = 4.5 per unit.
- Actual per-unit line current: (445/100)/0.95 = 4.684 per unit.
- Line is therefore loaded to: 4.684/4.5 x 100 = 104.1% of rating.

Branch current loadings are always checked at both terminals. Branch current is always taken to be the total current flowing into the branch as shown by I_i and I_j in Figure 6.44, "PSS®E Transmission Branch Equivalent Pi Model", including line charging and shunt reactor components. An overload is reported if the ratio of the greater of the two actual per-unit current loadings to the implied per-unit current rating multiplied by 100 exceeds a user-specified percentage threshold.

Transmission Lines

Transmission lines are modeled by specifying nonzero values for R_{ij}, X_{ij}, and B_{ch} during input. (The determination of the proper values of R_{ij}, X_{ij} and B_{ch} to characterize the transmission line is covered in Chapters 2 and 3.)

Line-connected shunt reactors should be specified by nonzero values as appropriate for the reactor parameters G_{Ii}, B_{Ii}, G_{Ij}, and B_{Ij}. Line reactors of equal size at both ends *should not* be handled by subtracting their per-unit susceptance from the line-charging susceptance.This handling makes it impossible to distinguish between capacitive and reactive susceptance when adjusting network impedances and admittances for off-nominal frequency in dynamic simulation calculations.

Transformers

Transformers are specified separately from branches. An activity such as CHNG *cannot* change a nontransformer branch model into a transformer model or reverse the side on which it is tapped; such an alteration of data constitutes new construction and hence is the responsibility of data input activities.

A transformer may have both an off-nominal turns ratio and a phase shift; that is $t_{ij} \neq 1$ and $\theta_{ij} \neq 0$. A 138/69 kV delta-wye transformer ratio with taps set for 141.45 kV, for example would have $t_{ij} = 1.025$ or 0.9756 and $\theta_{ij} = 30°$ or $-30°$.

A transformer winding where the ratio or phase-shift angle is to be adjusted automatically in power flow solutions must have values specified for the parameters listed in Table 6.11, "Transformer Winding Automatic Adjustment Parameters". These data may be entered and modified by transformer data records in the power flow raw data file or by data changing activities. The transformer adjustment enable flags can alternatively be changed on a subsystem basis by activity TFLG.

Table 6.11. Transformer Winding Automatic Adjustment Parameters

IREG	Bus where the voltage is to be controlled.
RMAX	Maximum per-unit winding turns ratio, maximum phase angle in degrees or voltage in kV.
RMIN	Minimum per-unit winding turns ratio, minimum phase angle in degrees or voltage in kV.
VMAX	If CNTRL=1, upper limit on controlled voltage, in pu; If CNTRL=2, upper limit of reactive power flow, in Mvar If CNTRL=3, upper limit of active power flow, in MW Not used if CNTRL=0 or CNTRL=4.
VMIN	If CNTRL=1, lower limit on controlled voltage, in pu; If CNTRL=2, lower limit of reactive power flow, in Mvar If CNTRL=3, lower limit of active power flow, in MW Not used if CNTRL=0 or CNTRL=4.
NTAP	Number of tap positions. Used only when CNTRL is 1 or 2.
TABLNO	Transformer impedance modification table number.
CNTRL	Control mode for automatic adjustments: 0 for fixed tap and phase shift 1 for voltage control 2 for reactive power control 3 for active power control 4 for dc line quantity control (valid for two-winding transformers only) Negate values to suppress automatic adjustment of winding.

A transformer winding is treated as a voltage controlled automatic tap-changer only if CNTRL is 1 and a nonzero bus number is entered for IREG. The transformer ratio is adjusted as if these conditions existed:

- Bus IREG is on the opposite side of the transformer from the tap (the winding 2 or winding 3 side) if IREG is positive.
- Bus IREG is on the same side of the transformer as the tap (the winding 1 side) if IREG is negative or is set to the from bus number.

Transformer Impedance Variation

As pointed out in Transformers in the Positive-Sequence, the standard transformer equivalent circuit used throughout PSS®E, as shown in Figure 4-16, can be quite accurate when the transformer has a fixed turns ratio or all taps on one side. The equivalent circuit of Figure 4-16, in which the impedance, x_{eq}, is constant may not be adequate, however, for some specialized transformers, particularly phase shifters.

Each transformer winding in PSS®E may have its effective leakage impedance made to be an arbitrary function of its tap position or phase shift, as shown in Figure 6.45, "Specification of Transformer Impedance Adjustment Factor". The actual impedance used to represent the transformer in calculations is ($k_z z_{eq}$), where k_z is an arbitrary factor specified by an 11-point graph as shown.

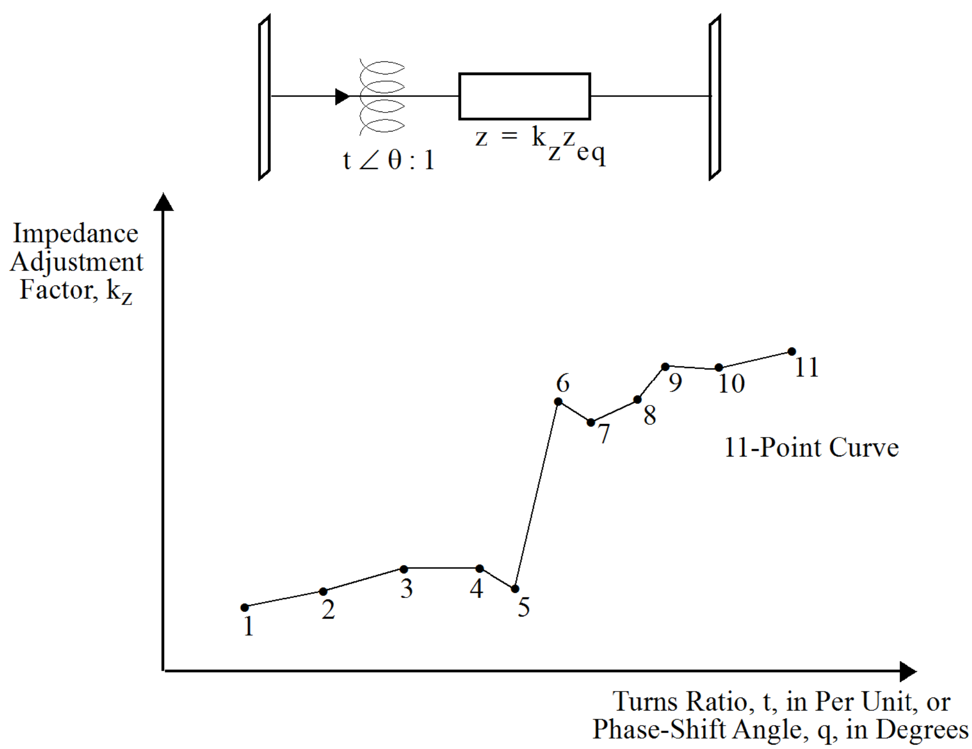


Figure 6.45. Specification of Transformer Impedance Adjustment Factor

The *nominal impedance*, z_{eq}, is entered as normal data for the transformer by the user. If no data is specified for the *impedance adjustment factor*, k_z, it takes the constant default value of unity. The impedance adjustment factor may be a function of either per-unit turns ratio, t, or phase-shift angle. The 11 points defining the factor, k_z, may provide any form of variation with the following exceptions:

- Points 1 through 11 must have successively greater values of tap ratio or phase shift.
- No two points may have the same value of tap ratio or phase shift.
- If the abscissa is phase shift, the abscissa values of points 1 and 11 must differ by at least five degrees. (Abscissa values could, for example, range from −15° to +30°.)

The abscissa values in the graph need not correspond to the values of per-unit turns ratio at actual tap-changer positions; though this is normally desirable.

Large changes in the value of k_z from one tap position to the next, e.g., between points 5 and 6, may cause convergence difficulties when automatic tap or phase-shifter adjustment is used in power flow solutions. Such difficulties should usually be overcome by allowing the solution to converge until a transformer makes a stable alternation between two taps or nearly equal phase-shift values, and then disabling the automatic adjustment. PSS®E allows the impedance of each transformer winding to be adjusted by a k_z factor; nine graphs, similar to Figure 6.45, "Specification of Transformer Impedance Adjustment Factor" define these adjustments.

Zero-Impedance Branches

Often a PSS®E user may want to represent either a bus tie or a jumper in a setup. PSS®E allows a low-impedance branch to be considered as a zero-impedance branch so that these bus ties and jumpers do not cause an increased bus tolerance to be specified to reach convergence.

For a branch from bus *i* to bus *j* to be considered a zero-impedance line, the following conditions must be true for these three parameters:

Parameter	Condition
R_{ij},	Resistance equal to zero.
$\lvert X_{ij} \rvert$,	Reactance magnitude less than or equal to the zero-impedance line threshold tolerance, THRSHZ.

Only during exiting of the solution activities will the flow on these branches be calculated. During the solutions of PSS®E, buses connected by a zero-impedance line (ZIL) are considered as one bus. Therefore, care is needed in specifying voltage-controlling equipment setpoints in a group. Activity CNTB with the suffix ALL will flag inconsistencies.

Note that X_{ij}, the branch impedance, cannot be set to exactly zero. If the user specifies a value of zero, the program will automatically set it to the zero-impedance line threshold impedance THRSHZ. THRSHZ set at a default value of 0.0001 per unit, may be changed in the solution parameter selection of activity CNTB and is saved with the case.

Figure 6.46, "Modeling Points to Note for Zero-Impedance Lines (ZIL)" shows some of the points to be noted when using zero-impedance lines.

Line-Drop Compensation

Often on radial circuits, it is desirable to maintain a predetermined voltage at a remote point from the transformer location, also known as the load center or regulating point. This voltage is kept constant at the load center, regardless of the magnitude or power factor of the load, by use of line-drop compensators in the regulator control circuit of the transformer. A line-drop compensator is a circuit made up of adjustable resistance and reactance elements.

The theory of operation of the line-drop compensator is illustrated in Figure 6.47, "Line-Drop Compensator Circuit". The voltage regulating relay (voltage sensor) has complete control of the regulator operations; that is, with a change in voltage across the relay, the relay actuates the regulator to return the voltage back across the relay to the predetermined value. If the voltage regulating relay is connected across the secondary of the potential transformer, the voltage across the regulator output terminals is held constant (i.e., within the relay bandwidth). In order for the voltage regulator to compensate for the line voltage drop between the regulator and the load center, a voltage must be introduced between the potential transformer and the voltage regulating relay. This voltage will subtract from the potential transformer voltage, be proportional to load current, and be dependent upon the load power factor. This is the function of the line-drop compensator.

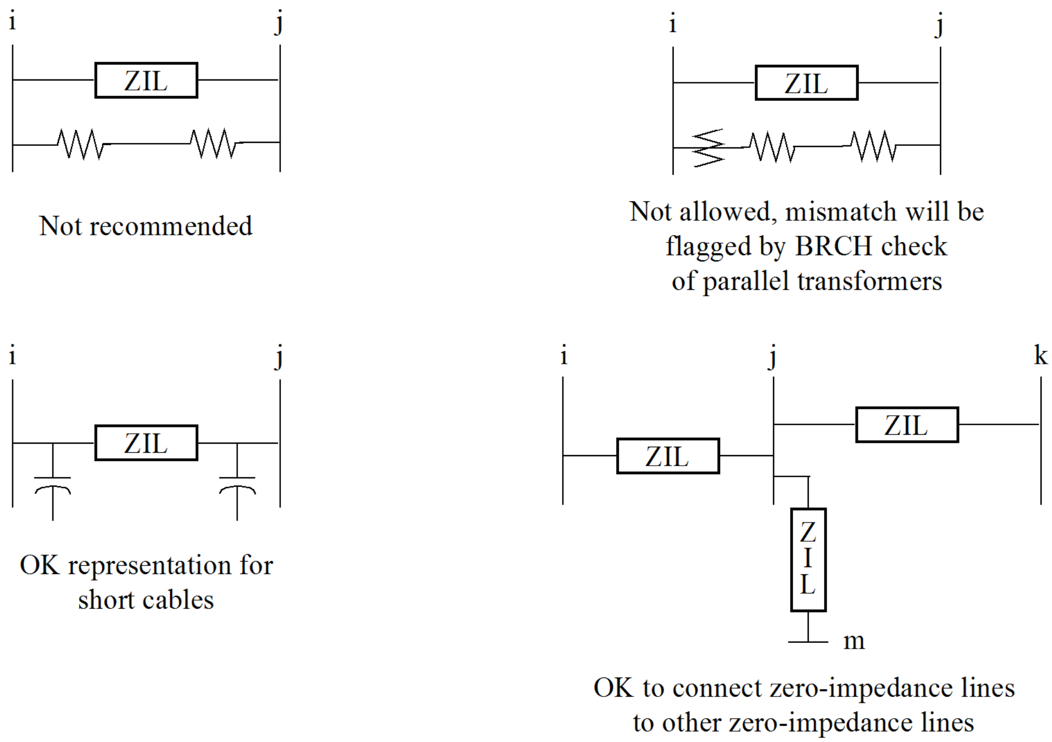
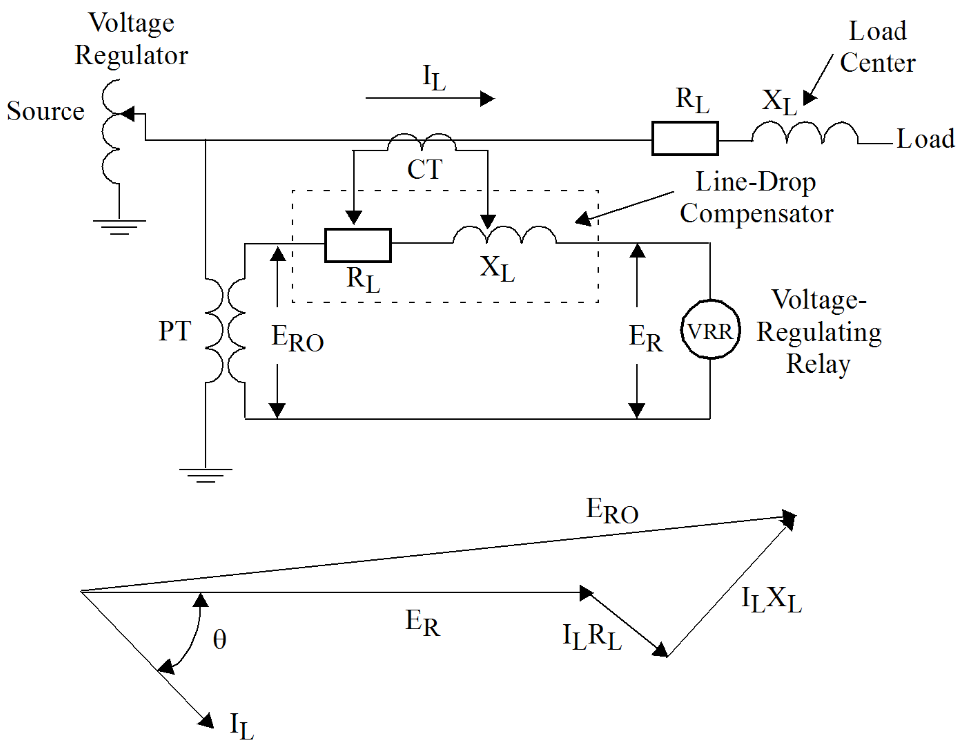


Figure 6.46. Modeling Points to Note for Zero-Impedance Lines (ZIL)



E_{RO}=Regulator output voltage
E_R=Relay voltage
I_L=Load current
R_L=Line resistance
X_L=Line reactance
θ=Load power factor angle

Figure 6.47. Line-Drop Compensator Circuit

The line-drop compensator is indicated in the dotted area of Figure 6.47, "Line-Drop Compensator Circuit" as only a simple schematic. Actually the compensator circuit may contain additional current transformers for further reduction of the current in the compensator elements, ballast reactors and auxiliary switches for reversing the voltage polarity across the compensator elements. The exact components of the compensator circuit will depend upon the manufacturer.

The current supplied by the potential transformer is almost in phase with the voltage. The current transformer produces an additional current, through the resistance and reactance element, which is directly proportional to the line current and in the same phase relation.

The voltage regulating relay is adjusted so that with zero load current, the output voltage of the regulator is equal to the voltage desired at the regulation point. Taking into account the instrument transformer ratio, the compensator is adjusted so that its elements are respectively proportional to the resistance, R_L, and reactance, X_L, of the feeder between the regulator and the regulation point. The regulator will then maintain the predetermined voltage at the regulating point. The similarity between the feeder circuit and the line-drop compensator circuit is illustrated by the phasor diagram, also in Figure 6.47, "Line-Drop Compensator Circuit", where E_{RO} is the feeder voltage at the regulator output terminals as well as the secondary voltage of the potential transformer. Similarly, I_L represents either the feeder load current or the secondary current of the current transformer; $I_L R_L$ is the voltage drop over the line resistance or that across the compensator resistance element caused by the current from the current transformer; and $I_L X_L$ is the voltage drop over the reactance of the line or the voltage introduced into the relay circuit by the reactance element. Therefore, E_R is the feeder voltage at the regulation point and the voltage across the relay; also, E_R would be within the bandwidth around the preset balance voltage of the relay.

The compensator elements are located on the regulator control panel, and the dials are calibrated in volts. When the element is set at a voltage value, it indicates the volts compensation obtained for that element when rated current is flowing in the secondary of the current transformer. If the current transformer (primary rating) and the regulator nameplate current rating are the same, the dial setting would be the volt compensation obtained at regulator nameplate loading.

In PSS®E, line-drop compensation is modeled by entering a compensating resistance, *CR*, and a compensating reactance, *CX*, as part of the transformer adjustment data. Both these values are entered in per-unit values according to the system base.

6.9.5. Generating Plants

Generator Data

Siting a generator or generators at a bus requires the entry of a generator data record from the power flow raw data file via activities READ, RDCH, or Reading Power Flow Data Additions from the Terminal. Generators may be sited at buses with any type code, but will be online only if the bus type code is 2 or 3. This practice allows one execution of activities READ,RDCH, or TREA to establish the construction of all generation in a system even though the loading data may correspond to a light-load system condition with a number of units or plants being off-line. The power flow raw data file must contain a data record for each generator. The data contained in each generator data record are defined in Table 6.12, “Generator Data Definitions ”.

Any number of generators may be sited at a bus. Hence the raw data file may contain several generator records for a given bus number, though each group of such records must contain a different machine identifier. Each generator modeled in the power flow setup may represent either a single rotor or a group of identical rotors with identical loading, as outlined in Section 5.5.2 Generator Power Flow Boundary Conditions.

Generator Status

Each generator is declared to be on- or off-line by its status code, ISG. Generation is placed online at a bus by both setting the bus type code to 2 or 3, and setting at least one generator status code to 1. Changing a bus type code to a value of 1, 4, or 5 takes all generators at the bus off-line regardless of the value of their status codes. Generator output parameters PGEN and QGEN are ignored when a generator is off-line.

Multi-unit Plants

The generator step-up transformer parameters may be set to default values, $(RT + jXT) = (0 + j0)$ and GENTAP = 1.0, which represent a generator connected directly to a bus. The principal example of such a setup is a cross-compound unit in which the high- and low-pressure units are bused at their terminals at the low-voltage side of the step-up transformer.

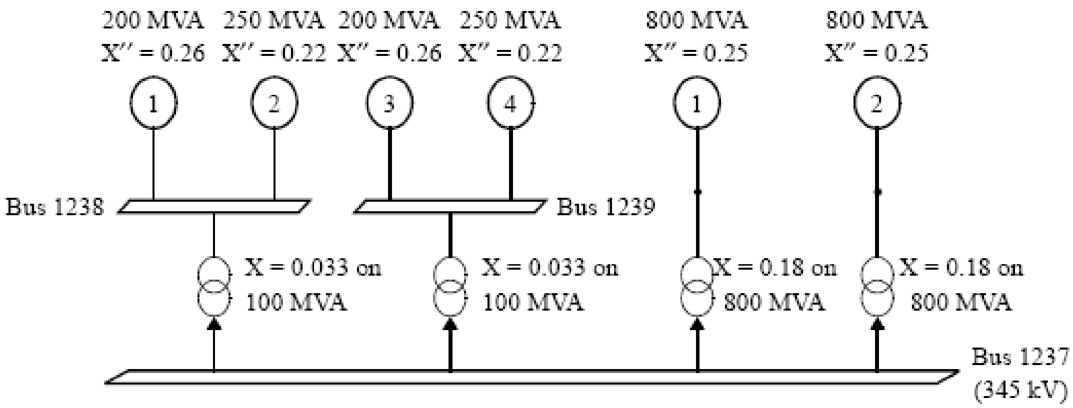
Table 6.12. Generator Data Definitions [a]

Parameter	Significance	Units
I	Bus where generator is connected	

Parameter	Significance	Units
ID	Machine identifier	1 or 2 characters using 1-9 and A-Z.
PG	Real power output at bus	MW
QG	Reactive power output at bus	Mvar
QT	Maximum reactive output at bus	Mvar
QB	Minimum reactive output at bus	Mvar
VS	Scheduled voltage	Per unit
IREG	The number of the bus where the voltage is regulated by this generator	
MBASE	Generator rating	MVA
ZR, ZX	Generator subtransient impedance	Per unit on generator base, MBASE
RT, XT	Step-up transformer impedance	Per unit on generator base, MBASE
GENTAP	Step-up transformer ratio (tap on high side)	Per unit
ISG	Generator status 1 = online 0 = off-line	
QPCT	Percent of total Mvar to hold voltage	%
PT	Maximum real output at bus	MW
PB	Minimum real output at bus	MW

[a]See Also Table 1 Base Voltage Values for Three-Phase Power System.

Figure 6.48, "Generator Data Records to Represent Plant with Two Cross-Compound and Two Tandem-Compound Unit" shows the data setup for a plant having two 450-MVA cross-compound units and two 800-MVA tandem-compound units all connected to a single 345-kV high-voltage transmission bus. Cross-compound unit No. 2 is off-line, as indicated by zero values of ISG for generators 3 and 4. The six-generator data records in this example show how each generator is represented individually. No generator step-up transformer data is entered for generators 1 through 4; these transformers are modeled as network branches. Note that branch 1239-1237 does not need to be taken out of service to model the off-line status of generators 3 and 4; all that is needed is to set the status flag, ISG, to 0 for these machines. In this example, the user has chosen to specify voltage at both the cross-compound unit 1 terminal bus and the 345-kV bus. The reactive power output of the cross-compound unit follows from the selection of bus voltages. An alternative, and perhaps more practical approach, would be to set the reactive power limits of generators 1 and 2 equal to their desired reactive power outputs, hence letting the voltage of bus 1238 float as required with respect to that of the 345-kV bus, bus 1237. When the collective reactive power output of a group of generators at a bus falls between the collected upper and lower limits, it is allocated among the generators in proportion to their real power outputs.



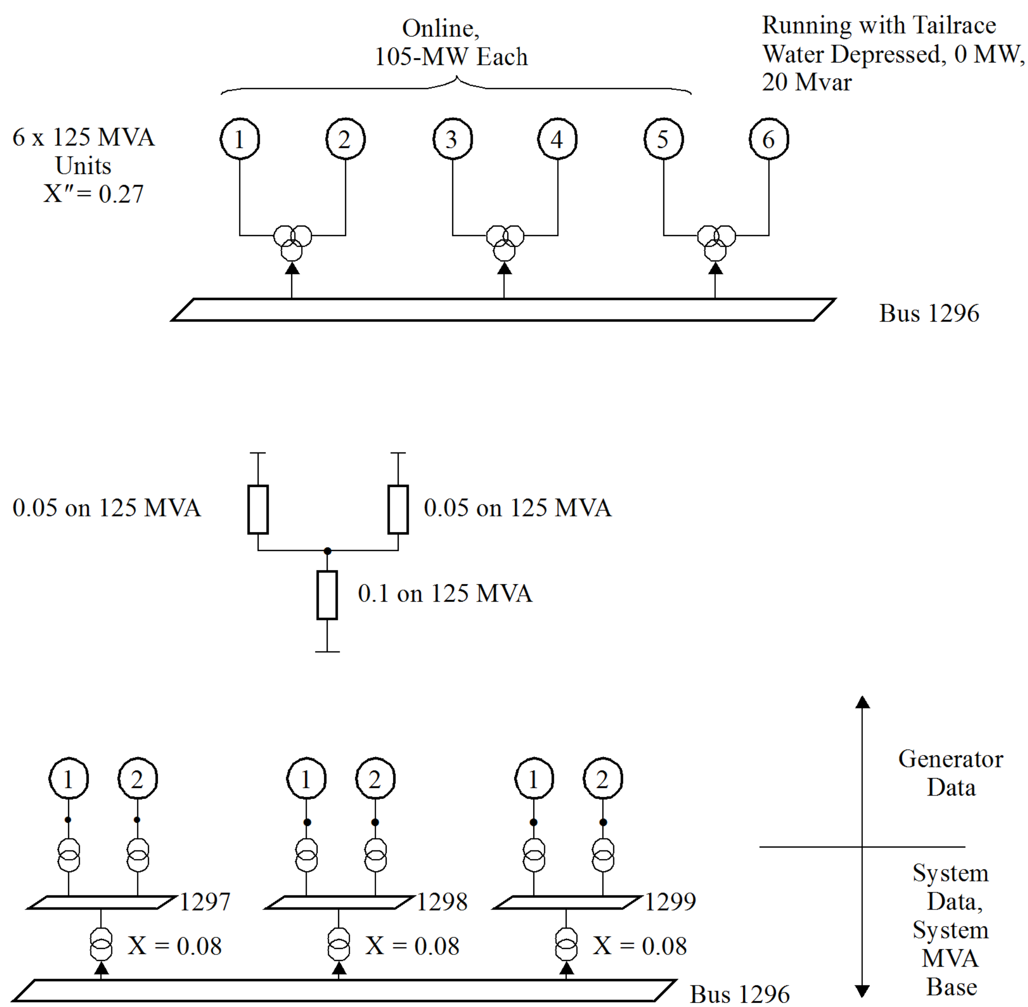
All Transformers at +5% Tap on 345-kV Side

I	ID	PG	QG*	QT	QB	VS	IREG	MBASE	XSOURCE		ZT		GENTAP	ISG	QPCT	PT	PB
1238	1	200	, ,	120	0	1.03	0	200	0	0.26	0	0	1.	1	50	200	60
1238	2	250	, ,	150	0	1.03	0	250	0	0.22	0	0	1.	1	50	250	75
1239	1	200	, ,	120	0	1.03	0	200	0	0.26	0	0	1.	0	50	200	60
1239	2	250	, ,	150	0	1.03	0	250	0	0.22	0	0	1.	0	50	250	75
1237	1	750	, ,	500	0	1.06	0	800	0	0.25	0	0.18	1.06	1	50	760	240
1237	2	750	, ,	500	0	1.06	0	800	0	0.25	0	0.18	1.06	1	50	760	240

*Not specified.

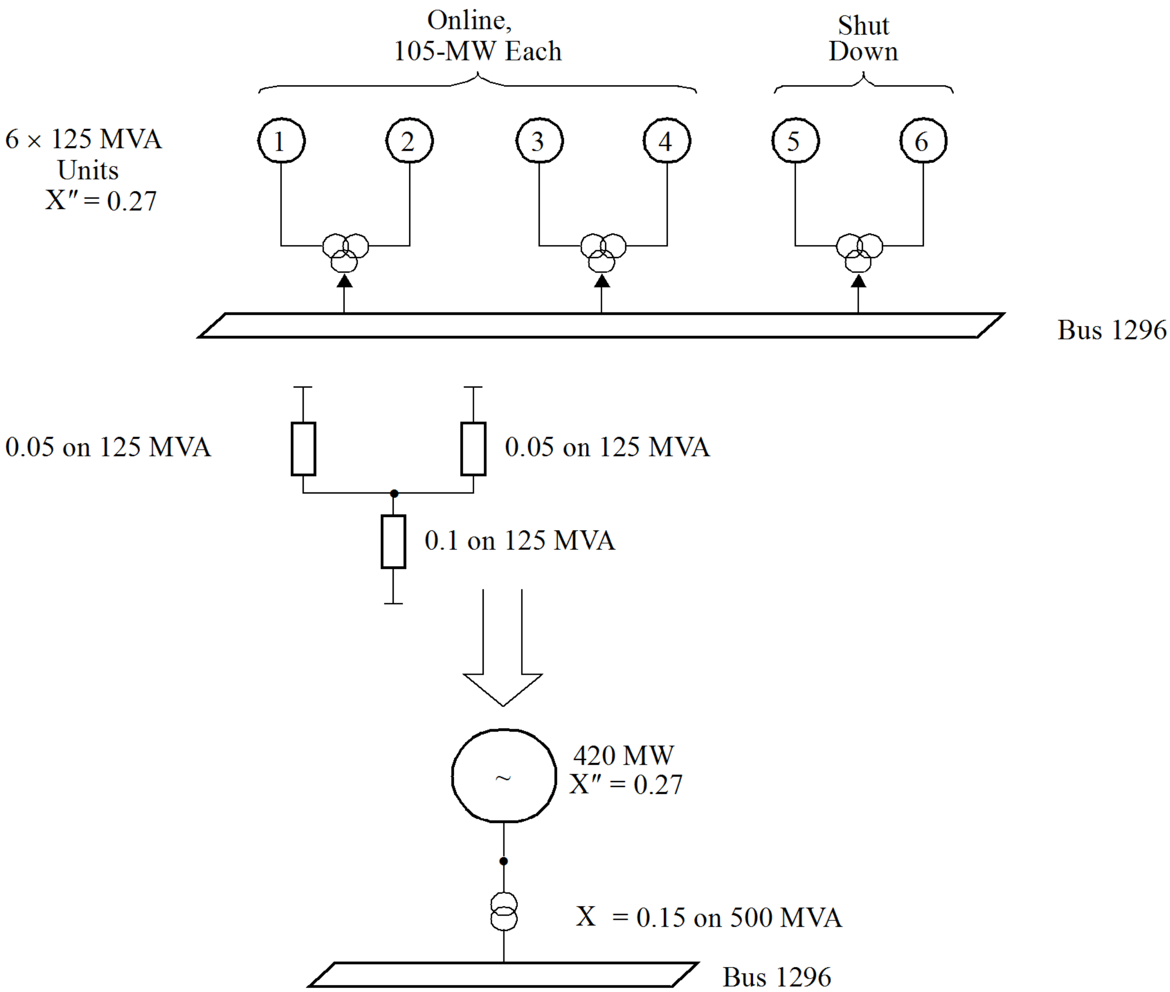
(One cross-compound unit off-line; cross-compounds regulate terminal bus voltage; tandem compounds regulate 345 kv bus voltage.)

Figure 6.48. Generator Data Records to Represent Plant with Two Cross-Compound and Two Tandem-Compound Unit



1297	1	105	, ,	60	-10	1.03	1296	125	0	0.27	0	0.05	1	1	50	112.5	0
1297	2	105	, ,	60	-10	1.03	1296	125	0	0.27	0	0.05	1	1	50	112.5	0
1298	1	105	, ,	60	-10	1.03	1296	125	0	0.27	0	0.05	1	1	50	112.5	0
1298	2	105	, ,	60	-10	1.03	1296	125	0	0.27	0	0.05	1	1	50	112.5	0
1299	1	105	, ,	60	-10	1.03	1296	125	0	0.27	0	0.05	1	1	50	112.5	0
1299	2	0	20	20	20	1.03	1296	125	0	0.27	0	0.05	1	1	50	112.5	0

Figure 6.49. Hydro Plant Representation with All Units Modeled Individually




```
1296 1 420, , 320 -40 1.03 1296 500 0 .27 0 .15 1.05 1 100 450 0
```

Figure 6.50. Hydro Plant Representation with Equally Loaded Identical Paired Units Modeled Collectively

Figure 6.49, "Hydro Plant Representation with All Units Modeled Individually" and Figure 6.50, "Hydro Plant Representation with Equally Loaded Identical Paired Units Modeled Collectively" show two alternative representations of a hydro plant having generators connected in pairs via three-winding generator step-up transformers. Figure 6.49, "Hydro Plant Representation with All Units Modeled Individually" shows the plant representation in which each unit is represented individually. This requires the introduction buses 1297, 1298, and 1299 to represent the center point of the three transformers. The three transformer high voltage legs are represented as transmission network branches, each with reactance of 0.08 per unit on a 100 MVA system base. Each low voltage leg is represented in conjunction with its corresponding generator as a generator step-up transformer with reactance of 0.05 per unit on the generator base of 125 MVA and unity tap ratio. This representation allows each individual generator to be placed at a different output and hence allows treatment of operating practices such as synchronous condenser running of a generator for spinning reserve purposes.

Figure 6.50, “Hydro Plant Representation with Equally Loaded Identical Paired Units Modeled Collectively” shows a simpler and more compact representation of the plant in which a single equivalent generator and step-up transformer are used to model the entire plant. In the figure, the value of MBASE has been set at 500, indicating that two pairs of units are online with all four generators carrying equal real and reactive load. This model can only be used when generators are operated at equal output and when they are taken on- and off-line in pairs.

6.9.6. Net Interchange, Loss Monitoring and Ownership

Areas, Zones and Owners

The power system model may be divided into areas and zones as shown in Figure 6.51, “Area and Zone Separations of the Power System Mode”. The system may contain up to the maximum number of areas and zones accommodated by the selected bus size level. At the 50,000 bus size level and above 1,200 areas and 2,000 zones are allowed. Neither areas nor zones need be continuous; a zone may overlap several areas, and vice versa.

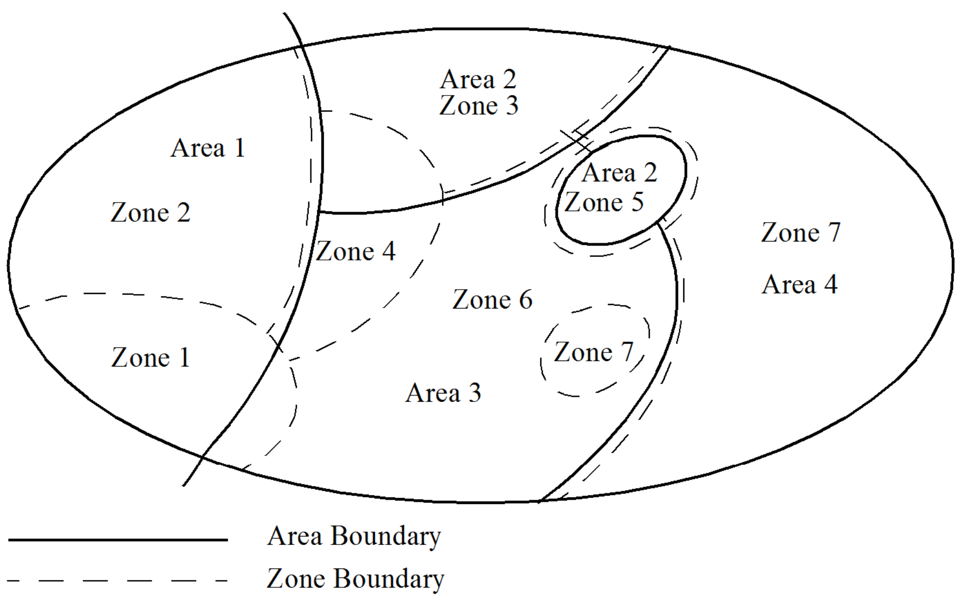


Figure 6.51. Area and Zone Separations of the Power System Mode

For example, in Figure 6.51, “Area and Zone Separations of the Power System Mode” area 2 and zone 7 are discontinuous. Each bus of the system model may have both an area and a zone designation included in its power flow raw data record; these designations may be reassigned by the many data editing functions in the program. Area and zone designations both default to 1 if not specified in power flow raw data. Areas may be given names via the net interchange control records of the power flow raw data file, while zone names are entered later in the data input file.

In addition to areas and zones, buses and loads may be designated to owners. Up to 1,200 owner designations are allowed. Machines and branches may have up to 4 owners, each having different percentage ownership. Bus and load ownership defaults to 1. The first machine owner defaults to 0. Likewise the first branch owner defaults to the I bus owner while the others default to 0. Ownership names are designated in the latter part of the raw data file.

Net Interchange and Losses

Reports of total load, generation, losses, and net interchange by area, zone and ownership can be found by selecting *Power Flow > Reports*. Totalization of interchange and losses requires recognition of the metered end of each transmission branch, as shown in Figure 6.52, "Recognition of Tie-Line Meter Position in Loss Totals". The meter is placed at the from bus of every branch unless the to bus number is entered with a negative sign in the power flow raw data record. The use of the negative to bus number is necessary, particularly for the case of a transformer where the meter is located on its untapped side. The branch data records for the five branches shown in Figure 6.52, "Recognition of Tie-Line Meter Position in Loss Totals" would read:

75	1	-etc.-
92	–75	-etc.-
58	63	-etc.-
75	63	-etc.-
101	207	-etc.-

Note that bus 92 must appear as the from bus of branch 92-75 as it must be indicated as the tapped side of the transformer.

In all PSS®E reports, line losses are taken as I^2 R and I^2 X and exclude the line-charging and line-connected shunt components.

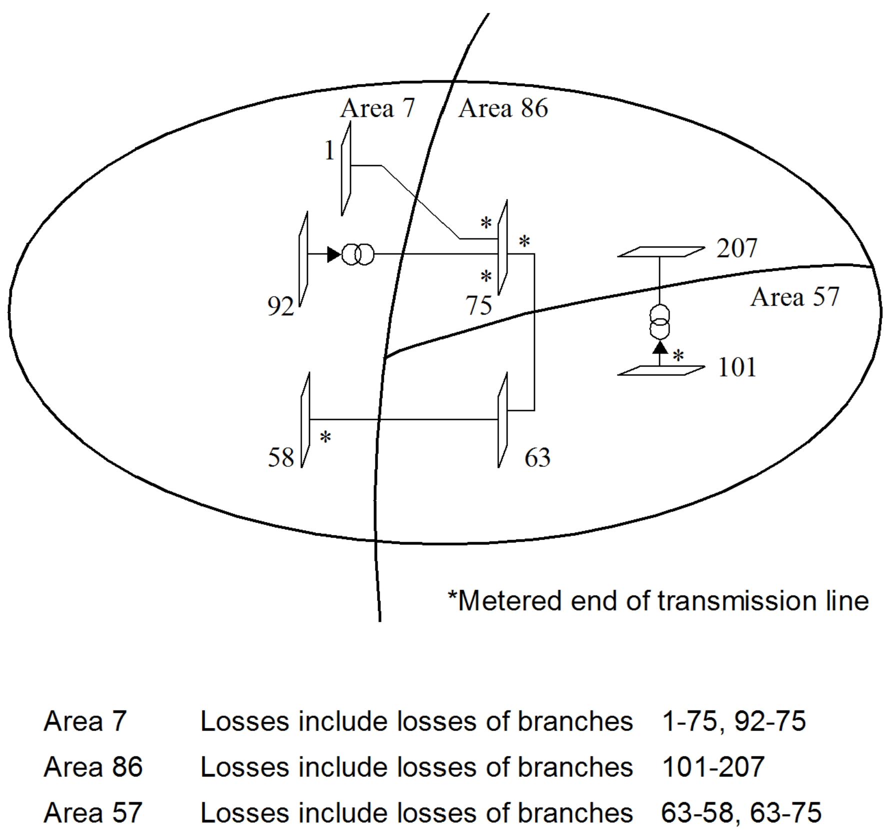


Figure 6.52. Recognition of Tie-Line Meter Position in Loss Totals

Net Interchange Control

The net interchange of some or all areas of the power system may be controlled during power flow solutions to lie within a specified band. Control is achieved by adjusting the output of a single area-swing generator within each area. While a net interchange control band may be specified for the area, or areas, containing a Type 3 (system swing) bus, no control can be exerted over the net interchange of such areas.

No control can be exerted over the net interchange of zones, either; zones are intended to facilitate the monitoring of the net interchange and losses that occur in subsections of the power system as a result of the imposition of a given load and generation distribution.The control data for area net interchange, as entered in a record per area in the power flow raw file, follow:

I	Area number.
ISW	Bus number of area swing generator (must be a Type 2 bus).
PDES	Center of desired net interchange band, MW.
PTOL	Tolerance on net interchange, MW (half-width of band).
'ARNAME'	Area name, up to twelve characters.

Area Transactions

Utilities usually do not set a goal to import/export a specific amount of MW as provided through net interchange control. Instead, most often based on economics, they will set up purchases and sales (transactions) with other utilities. These transactions can be entered into PSS®E and listed. PSS®E has no restriction, when entering transactions, that the utilities be neighbors; therefore, power could end up flowing through one or more intermediary utility systems (wheelers).

During data input, PSS®E prints a warning when the sum of the area transactions does not equal its net interchange control. This is just a warning; it is not always expected that the user will enter all transactions, especially for remote systems. The reading of transactions data has no input (it does not change) the area interchange value.

PSS®E data management will optionally update the interchange control value of both areas involved when an interchange value is modified. As an example, assume area 2 has a net interchange value of 250 MW and area 49 has a net interchange value of –400 MW. Initially, a transaction record of 100 MW from area 2 to area 49 was entered. If changing this transaction to 150, the user also could have the activity automatically change the area 2 net interchange value to 300 and the area 49 net interchange to –450 MW.

6.9.7. dc Transmission

General Considerations

PSS®E is able to handle up to 50 dc transmission circuits, consisting of a coordinated rectifier-inverter pair. Each pair places a coordinated set of special boundary conditions on the ac buses where the line is connected. All two-terminal dc lines consist of the line commutated converters. The converter stations may include a commutation capacitor. The existence of the commutation capacitor affects the extent of the dc line model and its impact on solution performance as explained below.

Direct Current Constraint Equations

A set of constraint equations exists for each converter. For each ac solution iteration the converter's state is determined to satisfy these constraints.

Noncapacitor Commutated Equality Constraint Equations

The equality constraints for the noncapacitor commutated two-terminal dc line consists of a series of linear and nonlinear equations that are symmetric between the rectifier and inverter. The rectifier and inverter are coupled by the transmission line equation, but the control equations for each converter are decoupled. The converter state can be obtained by solving these converter equations in the appropriate sequence. This solution process for the noncapacitor commutated dc line is non iterative and will reliably provide the ac solution process with dc boundary conditions for every ac iteration. The noncapacitor commutated dc line converter and the transmission line equations are:

Rectifier:

$$V_{dcr} = N_r \left(\frac{3\sqrt{2}}{\pi} E_{acr} \cos(\alpha) - \frac{3 X_{cr} I_{dc}}{\pi} - 2 R_{cr} I_{dc} \right) \tag{6.1}$$

$$\mu_R = \arccos\left(\cos(\alpha) - \frac{\sqrt{2} I_{dc} X_{cr}}{E_{acr}} \right) - \alpha$$

$$\tan(\phi_R) = \frac{2\mu_R + \sin(2\alpha) - [\sin 2(\mu_R + \alpha)]}{\cos(2\alpha) - [\cos 2(\mu_R + \alpha)]}$$

$$I_{acr} = \frac{\sqrt{6}\,N}{\pi} I_{dc}$$

Inverter:

$$V_{dci} = N_i \left(\frac{3\sqrt{2}}{\pi} E_{aci} \cos(\gamma) - \frac{3 X_{ci} I_{dc}}{\pi} - 2 R_{ci} I_{dc} \right)$$

$$\mu_I = \arccos\left(\cos(\gamma) - \frac{\sqrt{2} I_{dc} X_{ci}}{E_{aci}} \right) - \gamma$$

$$\tan(\phi_I) = \frac{2\mu_I + \sin(2\gamma) - [\sin 2(\mu_I + \gamma)]}{\cos(2\gamma) - [\cos 2(\mu_I + \gamma)]}$$

$$I_{aci} = \frac{\sqrt{6}\,N}{\pi} I_{dc} \tag{6.2}$$

Transmission Line:

$V_{dci} = V_{dcr} - R_{dc} I_{dc}$

where:

V_{dcr}, V_{dci}

dc line voltages, (V).

E_{acr}, E_{aci}

Open circuit line-to-line voltages on the dc side of converter transformers, (V).

N_r, N_i

Number of bridges in series.

X_{cr}, X_{ci}

Converter transformer dc side winding commutating reactances, Ω /phase.

R_{cr}, R_{ci}

Converter transformer dc side winding commutating resistances, Ω /phase.

I_{dc}

dc line current, A.

I_{acr}, I_{aci}

Total ac line current flowing into the ac side of converter transformers.

$\cos_r$, $\cos_i$

ac power factor.

α

Rectifier firing delay angle.

γ

Inverter margin angle.

μ_R

Rectifier overlap angle.

μ_I

Inverter extinction angle.

Capacitor Commutated Equality Constraint Equations

The capacitor commutated dc line consists of the transmission line and at least one capacitor commutated converter. The constraints for the capacitor commutated converter are a system of linear equations. When both rectifier and inverter are capacitor commutated, each converter's system of equations may be coupled or decoupled to the other depending on the control mode. The converter state must be obtained by solving these converter equations simultaneously. A Newton solution process is employed for the capacitor commutated dc line. This process is iterative and depending on the condition of the problem it may fail to converge and thus may fail to provide the ac solution process with reliable dc boundary conditions for every ac iteration. Newton solution control parameters, including iteration limit and acceleration factor are provided with the two-terminal dc line data.

The equality constraint equations employed are proprietary information provided by ABB.

Direct Current Control

Each dc converter (rectifier or inverter) is represented as shown in Figure 6.53, "A dc Terminal Arrangement in Absence of Tertiary-Connected Reactive Supply or Filtering Equipment". The bridge control angle (α or γ) and transformer tap position are adjusted by the power flow solution logic to control dc voltage and current, subject to control angle limits. The dc lines, when controlling dc voltage and current, are operated according to the principles illustrated in Figure 6.54, "Direct Current (dc) Transmission Control Regimes". Figure 6.54, "Direct Current (dc) Transmission Control Regimes"a shows the relationship between rectifier and inverter characteristics in normal operation when the ac voltages at both rectifier and inverter are close to normal. The inverter margin angle, γ , is adjusted to maintain a specified voltage on the dc line. The voltage control is current compounded to allow the voltage to be specified at a designated point along the line. The extent of the current compounding is specified by the compounding resistance, R_{comp}, which is normally less than the full line resistance, R_{dc}. As long as the rectifier is able to maintain control of line current, the inverter adjusts its margin angle, γ , to maintain line voltage at the required value.

Figure 6.54, "Direct Current (dc) Transmission Control Regimes"b shows the relationship between rectifier and inverter characteristics when the ac voltage at the rectifier is depressed. Here control of dc voltage is abandoned and the inverter margin angle, γ , is adjusted to maintain the dc current at a value which is the desired current reduced by the current margin, Δ I. Intermediate combinations of rectifier and inverter ac voltages can result in operation at current values between the desired current and the inverter control current, but this is a rare occurrence.

The line may be instructed to hold either a desired dc current or a desired dc power. The latter may be held at either the rectifier or inverter end. Specifying a positive power setpoint causes rectifier power to be set; specifying a negative power setpoint fixes inverter received power. A current setpoint is always a positive value.

For a noncapacitor commutated converter the power control is maintained as long as the dc voltage at the inverter exceeds a specified value, VCMODE. This control prevents the line from seeking a combination of low dc voltage and high dc current. This combination will produce commutation difficulties in the inverter as well as an excessive ac reactive power requirement at both converters.

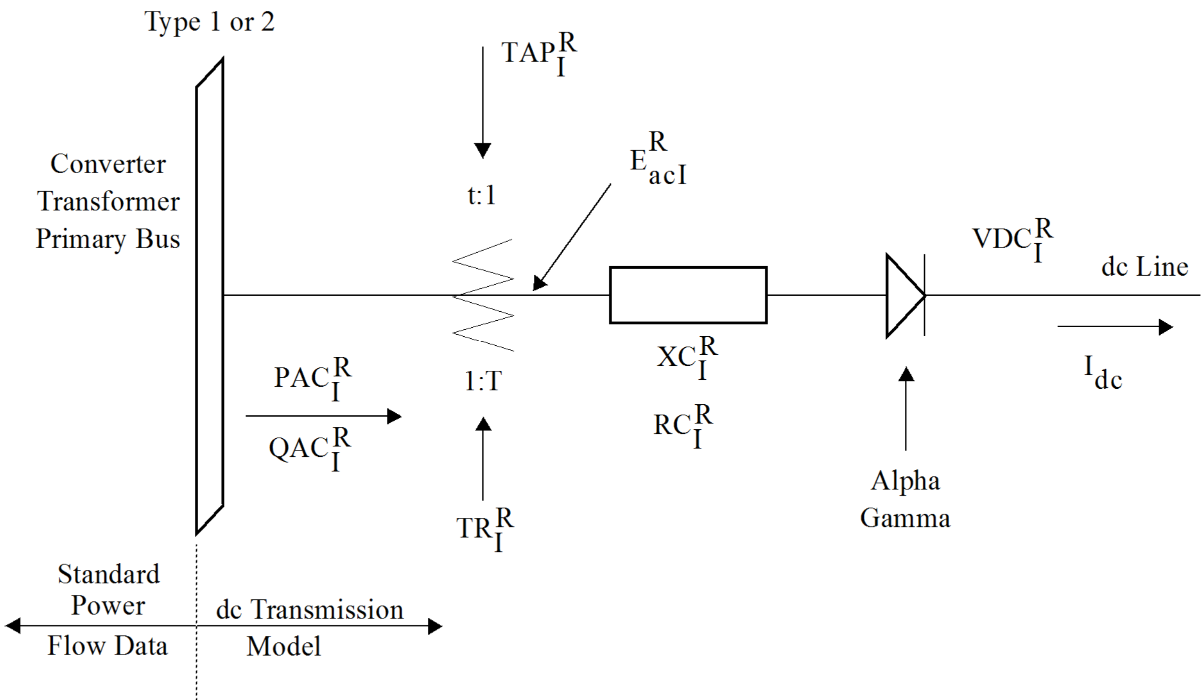
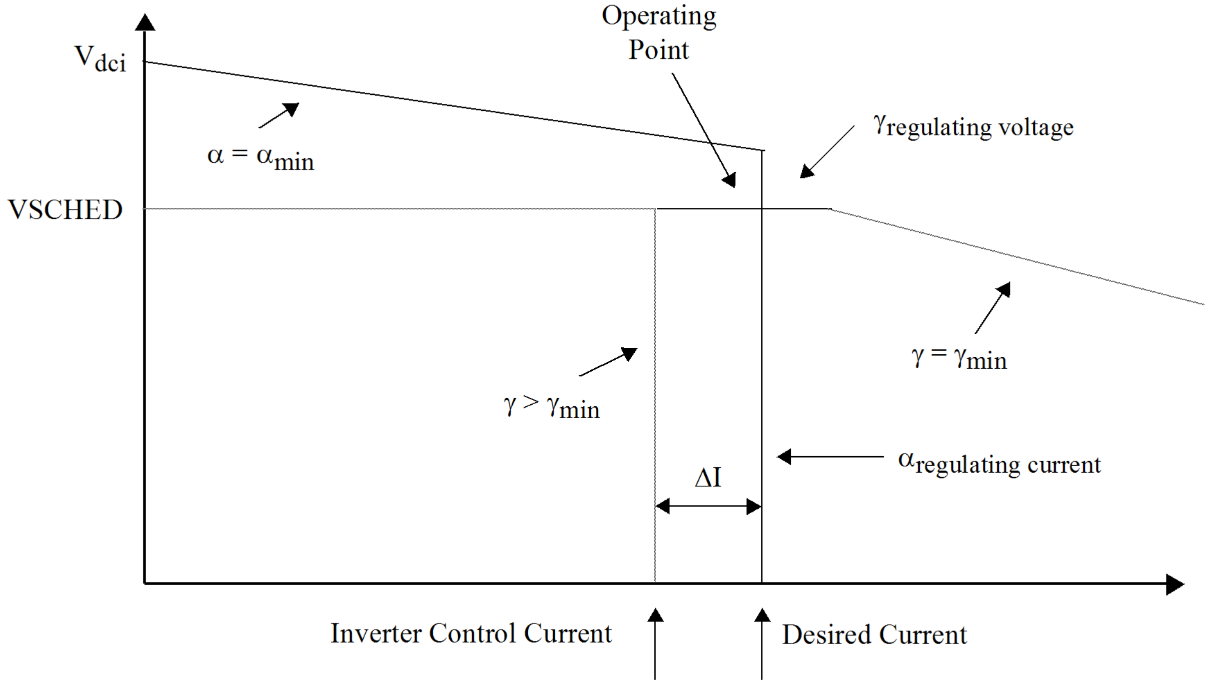
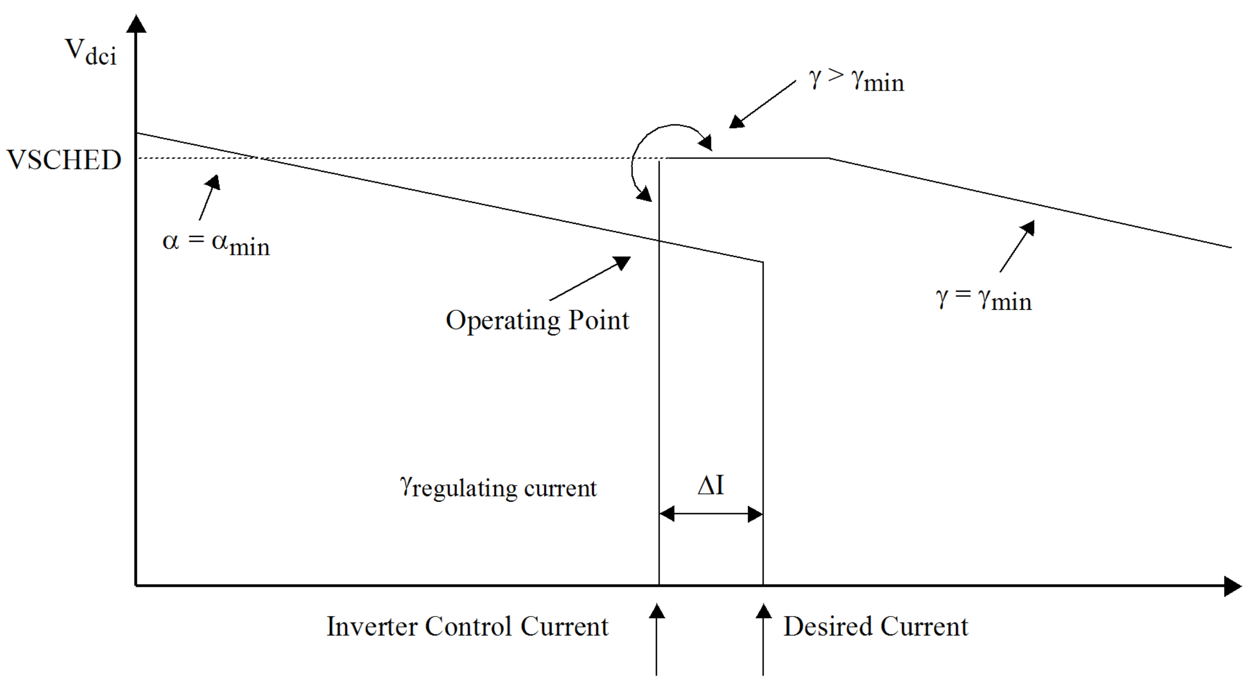


Figure 6.53. A dc Terminal Arrangement in Absence of Tertiary-Connected Reactive Supply or Filtering Equipment



a. Converter Characteristics when Rectifier ac Voltage is Sufficient for α Control of Current



b. Converter Characteristics when Rectifier ac Voltage is Depressed; Current is Reduced by ΔI and Regulated by γ

Figure 6.54. Direct Current (dc) Transmission Control Regimes

If the inverter dc voltage falls below the value, VCMODE, when the line is specified to be in power control mode, the line current is controlled to:

$$I_{dc} = \frac{\text{Desired Power}}{\text{Scheduled dc Voltage}}$$

leaving the actual dc received power to fall in proportion to the dc voltage.

For a capacitor commutated converter dc power control implies the computation of a desired dc current which satisfies the dc power schedule when dc voltage schedule is satisfied. The voltage threshold, VCMODE, plays no role in power control for a capacitor commutated converter.

The control logic adjusts the converter transformer tap positions to attempt to hold the bridge firing angles above minimum values and below maximum. The minimum values of the firing angles, α_{min} and γ_{min}, are firm limits; the bridges will not be operated in power flow solutions with firing angles below these values. The maximum values of the firing angles, α_{max} and γ_{max}, are objectives, but not firm limits; the converters may be operated in power flow solutions with firing angles above these limits if the converter transformer tap positions are at the ends of their ranges or if the desired angle ranges are narrow relative to the tap-steps. Converter taps are adjusted only until the corresponding bridge firing angles are between their specified maximum and minimum values; taps are not adjusted to minimize firing angles if they fall between their corresponding maxima and minima. Accordingly, the ranges of the bridge firing should be treated as the optimum bands for the various converters, with recognition that operation at a firing angle above the specified maximum value may be necessary for some combinations of scheduled dc power, dc voltage, and ac system conditions.

When the γ_{min} and γ_{max} values are equal, the inverter operates at a fixed margin angle instead of controlling dc voltage; the converter transformer taps adjust to obtain the desired dc voltage. If an ac transformer is used, the tap is only moved if the desired dc voltage is outside the range of a user specified value of DCVMIN and the desired dc voltage.

Power flow solution options may be employed to lock the converter tap positions at initial value. For this condition the converter control angles are forced to be above their minima, but no attempt is made to keep them below the specified maxima.

All dc lines are treated in PSS®E as an integral part of the power flow working case, and their flow is recognized in all output and report preparation activities. dc lines are metered at the ac side of either their rectifier or inverter bridges. Based on user input, the real and reactive power flows applied to loss calculations and area interchange logic are PACR or PACI and QACR or QACI, as shown in Figure 6.53, “A dc Terminal Arrangement in Absence of Tertiary-Connected Reactive Supply or Filtering Equipment”.

Direct Current Line Data

The data to be specified by the user are identified in Figure 6.53, “A dc Terminal Arrangement in Absence of Tertiary-Connected Reactive Supply or Filtering Equipment” through Figure 6.55, “Current Compounds of dc Line Voltage Control Inverter Controls dc Voltage at Inverter dc Side to $V_{dci} = V_{setpoint} - R_{comp} i_{dc}$”. Unlike ac systems data, the majority of dc line data is specified in physical units (kilovolts, amperes, and ohms). All dc line data may be maintained using the program’s data input and data editing facilities.

Each converter transformer is characterized by its leakage impedance and by both its nominal absolute turns ratio and its per-unit turns ratio in relationship to nominal value. Figure 6.53, “A dc Terminal Arrangement in

Absence of Tertiary-Connected Reactive Supply or Filtering Equipment" shows that the absolute turns ratio must be specified as:

$$T = TR = \frac{\text{dc Side, Base ac Voltage}}{\text{ac Side, Base ac Voltage}}$$

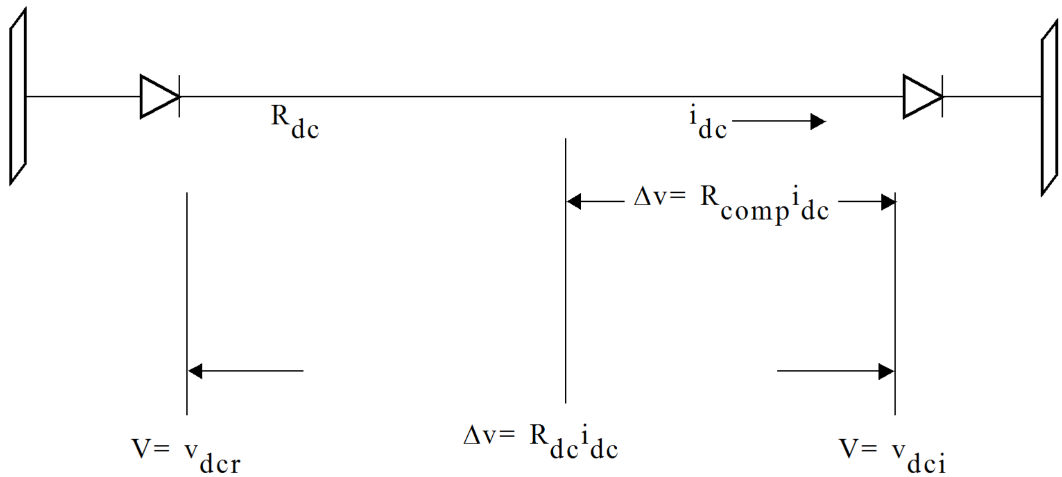


Figure 6.55. Current Compounds of dc Line Voltage Control Inverter Controls dc Voltage at Inverter dc Side to $V_{dci} = V_{setpoint} - R_{comp} i_{dc}$

While the per-unit tap ratio must be specified as:

$$t = TAP = \frac{\text{ac Side, Open Circuit Voltage}}{\text{dc Side, Open Circuit Voltage}} \times TR$$

Converter transformer commutating reactance and resistance must be specified in ohms, as seen from the dc side terminals of the transformer.

The definitions of the dc line data items are as follows, with (*R*,*I*) indicating rectifier and inverter, respectively.

TR(R,I)

Actual open-circuit voltage ratio (i.e., nominal turns ratio) for line-to-line voltages on primary and secondary windings of converter transformer. Secondary voltage divided by primary voltage.

TAP(R,I)

Per-unit variation of actual voltage ratio from nominal due to off-nominal tap setting, with taps assumed to be on primary winding.

NB(R,I)

Number of three-phase converter bridges in series, with respect to the dc side of converter.

EBASE(R,I)

Line-to-line base rms voltage at primary ac system bus (kV).

XC(R,I)

Converter transformer secondary commutating reactance in ohms per bridge (see the section called “Optional Direct Current Terminal Line Logic”).

RC(R,I)

Converter transformer secondary commutating resistance in ohms per bridge (see the section called “Optional Direct Current Terminal Line Logic”).

XCAP(R,I)

Commutating capacitor reactance magnitude in ohms per bridge. Enter a value that is greater than zero to represent a commutation capacitor.

IC(R,I)

Angle measuring bus if not converter ac bus.

IF(R,I)

Tapped side (from bus) number of an ac transformer branch.

IT(R,I)

Untapped side (to bus) number of an ac transformer branch.

ID(R,I)

Circuit identifier of above transformer.

ALFMIN

Minimum firing (delay) angle of rectifier in degrees.

GAMMIN

Minimum margin angle of inverter in degrees.

ALFMAX

Maximum firing (delay) angle objective for rectifier in degrees.

GAMMAX

Maximum margin angle objective for inverter in degrees.

MDC

dc line control mode.

0 = blocked line.

1 = constant power.

2 = constant current.

RDC

dc line resistance, ohms.

SETVAL

Desired dc power in MW or desired dc current in amperes. Positive value specifies current or rectifier power; negative value specifies inverter power.

TAPMX(R,I)

Maximum value of converter transformer tap ratio (pu).

TAPMN(R,I)

Minimum value of converter transformer tap ratio (pu).

TSTP(R,I)

Converter transformer tap-step (pu).

VSCHED

Scheduled dc voltage (kV).

RCOMP

Compensating resistance for voltage control, Ω .

DELTI

Current margin measured per unit of current setpoint.

VCMODE

Minimum inverter dc voltage for power control mode (kV).

DCVMIN

Minimum compounded dc voltage (kV).

CCCITMX

Iteration limit for capacitor commutated two-terminal dc line Newton solution procedure.

CCCACC

Acceleration factor for capacitor commutated two-terminal dc line Newton solution procedure.

These items are the union of possible data for both capacitor commutated and noncapacitor commutated dc lines. A dc line is treated as capacitor commutated when XCAPR>0.0, or XCAPI>0.0 Otherwise the dc line is noncapacitor commutated. The capacitor commutated dc line model precludes:

- Converter transformer resistance for any capacitor commutated converter, RC(R,I).
- Remote angle measuring bus for either converter, IC(R,I).
- Remote ac control transformer for either converter, IF(R,I), IT(R,I) and ID(R,I).
- Power control voltage threshold, VCMODE.

The converter transformer resistance is precluded only for that converter for which XCAP is greater than zero. This may be the rectifier, the inverter or both. Values presented for these data items are ignored for capacitor commutated converters.

Each dc line appears to the ac system as two loads; (PACR + *j*QACR) at the rectifier and (PACI + *j*QACI) at the inverter. These loads are calculated and applied during the power flow solutions at the converter primary buses. In normal dc line operation, PACR, QACR, and QACI are positive, while PACI is negative. These loads are used only during solutions and are not associated with ac buses during output or load totaling operations.

During each power flow solution, the dc line logic calculates and places the following items in the dc line data section of the power flow working file:

PAC,QAC(R,I)

dc line equivalent ac load, MVA

ALFA

Rectifier delay angle, degrees

GAMMA

Inverter margin angle, degrees

VDC(R,I)

dc line voltage, V

DC

dc line current, A

TAP(R,I)

Off-nominal tap setting (pu)

Note that for noncapacitor commutated converters, if a commutating resistance value, not equal to zero, is entered, PACR or PACI will not be equal to the desired dc power because of these losses. SETVAL is the desired power on the dc line, not at the ac bus. For capacitor commutated converters the inverter margin angle is with respect to the bridge voltage as opposed to the commutation bus voltage.

Optional Direct Current Terminal Line Logic

Figure 6.56, “Treatment of Three-Winding dc Converter Transformers” shows the configuration assumed by the dc line logic when there is a synchronous condenser or static capacitor bank connected to a tertiary winding of the noncapacitor commutated converter transformer. Connecting the reactive power supply through a three-winding transformer is not employed for capacitor commutated converters.

The rules governing the setup of this converter configuration follow:

- The dc converter model should be set up as if a two-winding converter transformer is fed from the star-point of the star equivalent of the actual three-winding transformer arrangement.
- The primary, star-point, and tertiary buses must appear in the power flow with types as shown in Figure 6.56, “Treatment of Three-Winding dc Converter Transformers”.
- The three-winding converter transformer is represented partly by standard ac power flow branches and partly by the dc line data. The primary-to-star-point and star-point-to-tertiary branches must be included as standard ac power flow branches. The star-point-to-secondary branch is not included in the ac power flow data.
- The primary-to-star-point branch should be a standard ac power flow branch.
- There must be no ac load at the star-point bus.
- The reactances X_p and X_t must be specified as conventional power flow branch impedances as follows:

X_p

Per-unit value of primary-to-star-point reactance for star equivalent of the three-winding transformer (on system MVA base), for all converters in parallel.

X_t

Per-unit value of star-point-to-tertiary reactance for star equivalent of the three-winding transformer (on system MVA base), for all converter transformers in parallel.

- Tap range and tap-step used for control at the converter must be specified with dc converter data even if it is done by an ac transformer. The ac transformer control adjustment data is ignored if it is used for dc control.
- The resistance, RCR or RCI, and reactance, XCR or XCI, must be set to the star-point-to-secondary impedance for the star equivalent of the three-winding transformer, in ohms for each transformer. The user then has the option of specifying with the converter data one of the ac transformer branches, i.e., primary-to-star-point or even star-point-to-tertiary as that used for control. The user can also specify an ac bus to use for measuring converter angles (commutating bus), such as the bus where a synchronous condenser

exists. Though the above configuration was for a three-winding transformer, no restrictions exist, when representing noncapacitor commutated converters, for choosing an ac transformer branch for control or an ac bus for measuring converter angles; therefore, other combinations of equipment are possible.

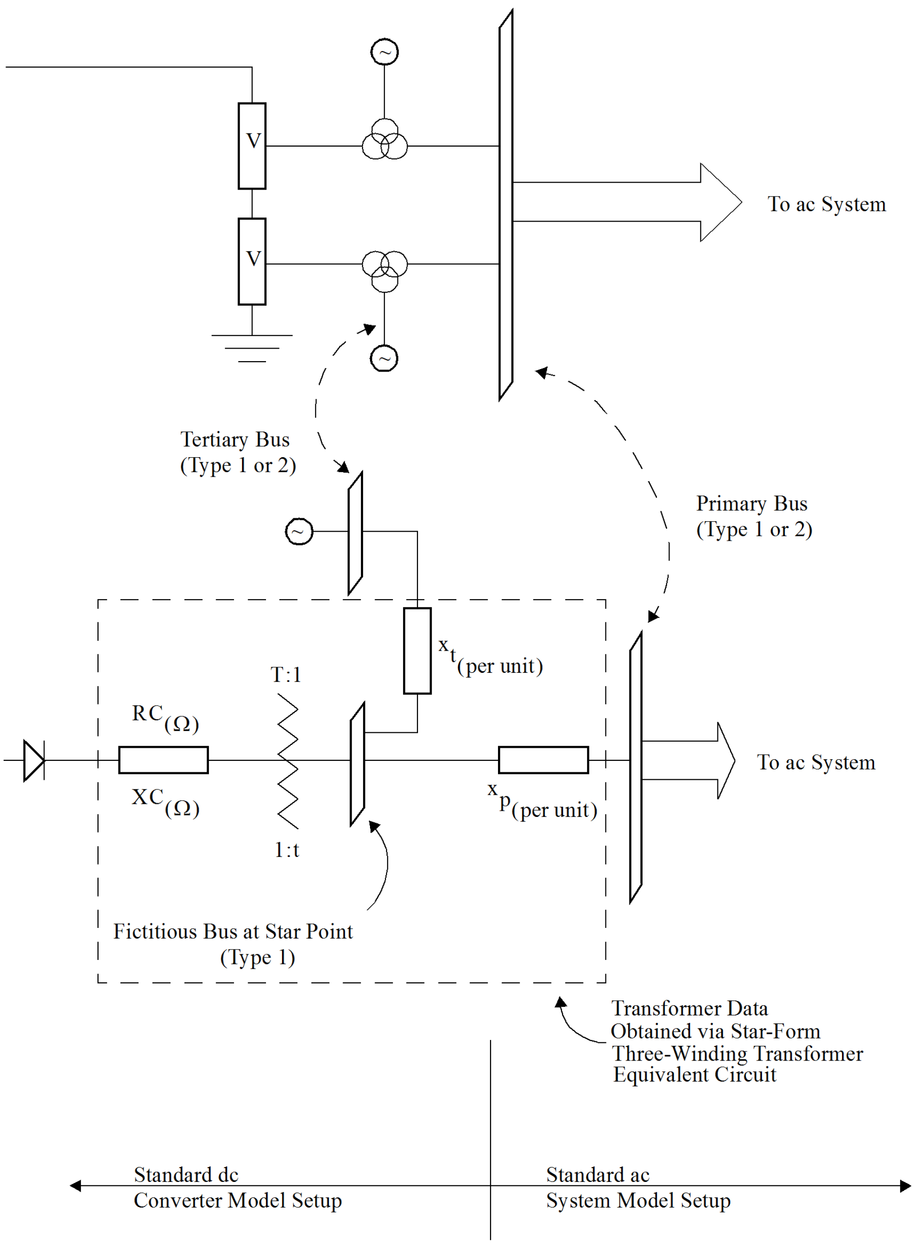


Figure 6.56. Treatment of Three-Winding dc Converter Transformers

Example of Direct Current Line Setup

As an example of dc transmission data setup, consider the dc transmission line shown on Figure 6.57, "Sample dc Transmission Line". This line is rated at ±550 kV, 2750 A, and 3025 MW. Its rectifier consists of four transformer-converter units connected in parallel to a 500-kV generating plant bus and in series on the dc side. The generators are connected to the 500-kV bus by step-up transformers and short 500-kV overhead lines (generator leads), in anticipation of future connection of 500-kV ac transmission to the same bus. The inverter station consists of four transformer-converter units connected to a 230-kV bus with a 400-Mvar synchronous condenser on the tertiary winding of each transformer. Harmonic filters appear at 60 Hz as a 100-Mvar static shunt capacitor on each transformer tertiary winding. The three-winding inverter transformers have their adjustable taps on their primary (230-kV) sides. Neither converter is capacitor commutated. Calculation of data to represent this transmission system, on the basis of preliminary estimates of equipment parameters follows.

Line and Bus Numbers

The terminals will be connected as shown in Figure 6.57, "Sample dc Transmission Line". The rectifiers will use the two-winding converter transformer model of Figure 6.53, "A dc Terminal Arrangement in Absence of Tertiary-Connected Reactive Supply or Filtering Equipment" and its arrangement as shown in Figure 6.58, "Rectifier Station Arrangement". The inverters will use the three-winding transformer model of Figure 6.56, "Treatment of Three-Winding dc Converter Transformers" and its arrangement as shown in Figure 6.59, "Inverter Station Arrangement with Tertiary Connected Synchronous Condensers". Each pole will be represented as a single dc line with a voltage rating of 550 kV, and with two converters in series.

Dummy buses 1401 through 1404 will be placed at the inverter end to accommodate the three-winding transformer model as shown in Figure 6.59, "Inverter Station Arrangement with Tertiary Connected Synchronous Condensers". Because the tap-changer is on the primary side, the tap modeled in the inverter dc subsystem is considered fixed at the ratio corresponding to the dc voltage specified for the star-point bus. The variable tap in the ac side winding is modeled in the ac system. All data will be stated for one 550-kV dc line model. The two lines will be operated with equal loading setpoints in all normal power flow studies. Selective blocking of one of the two dc lines will be used in subsequent dynamic simulations.

NBR	=	2
NBI	=	2
EBASER	=	500 kV
EBASEI	=	230 kV

Line Resistance

The resistance of the conductor chosen for the line is 0.035 ohms/mile. There are two conductors per bundle and the line is 750 km (469 miles) long.

$$RDC = 0.035 \times \frac{469}{2} = 8.2\Omega$$

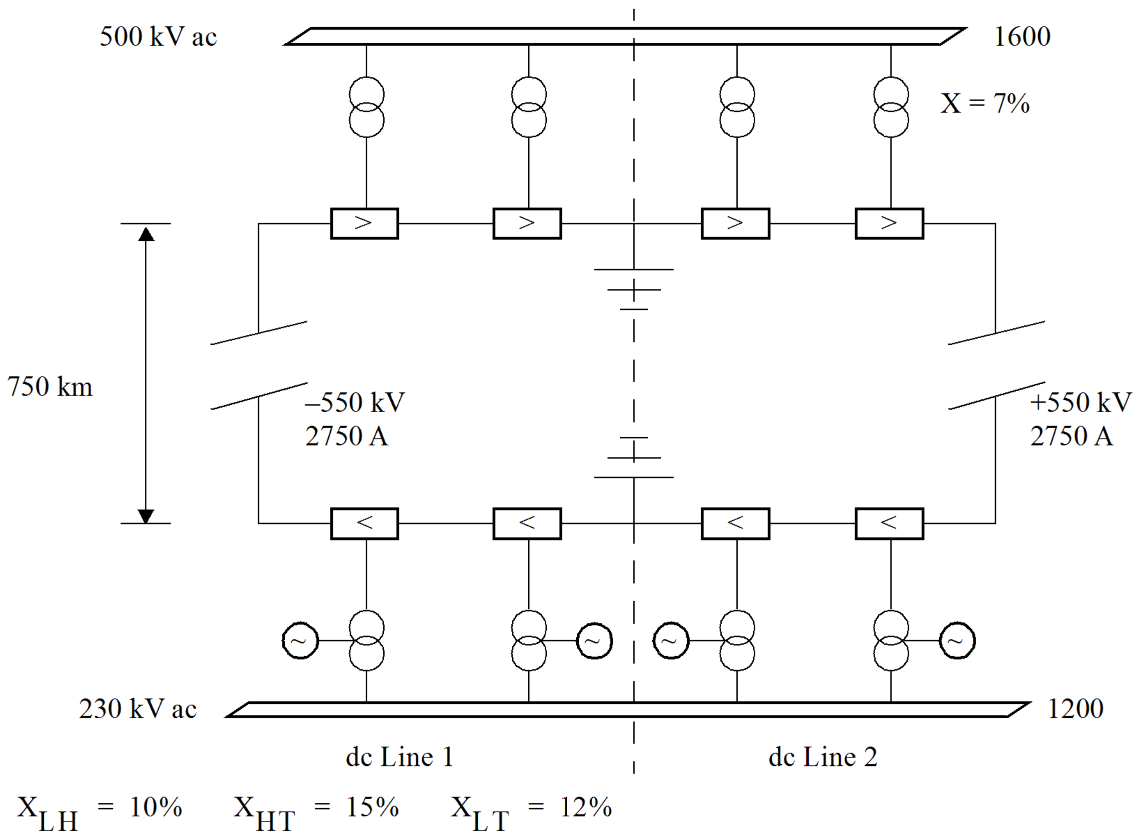


Figure 6.57. Sample dc Transmission Line

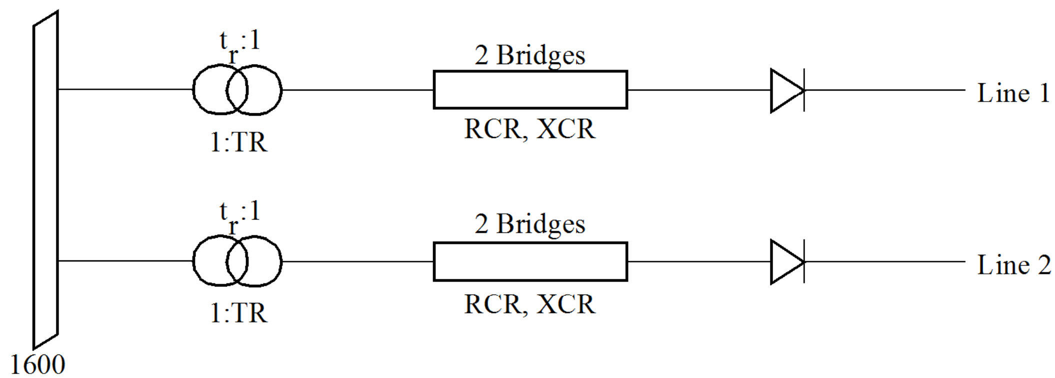


Figure 6.58. Rectifier Station Arrangement

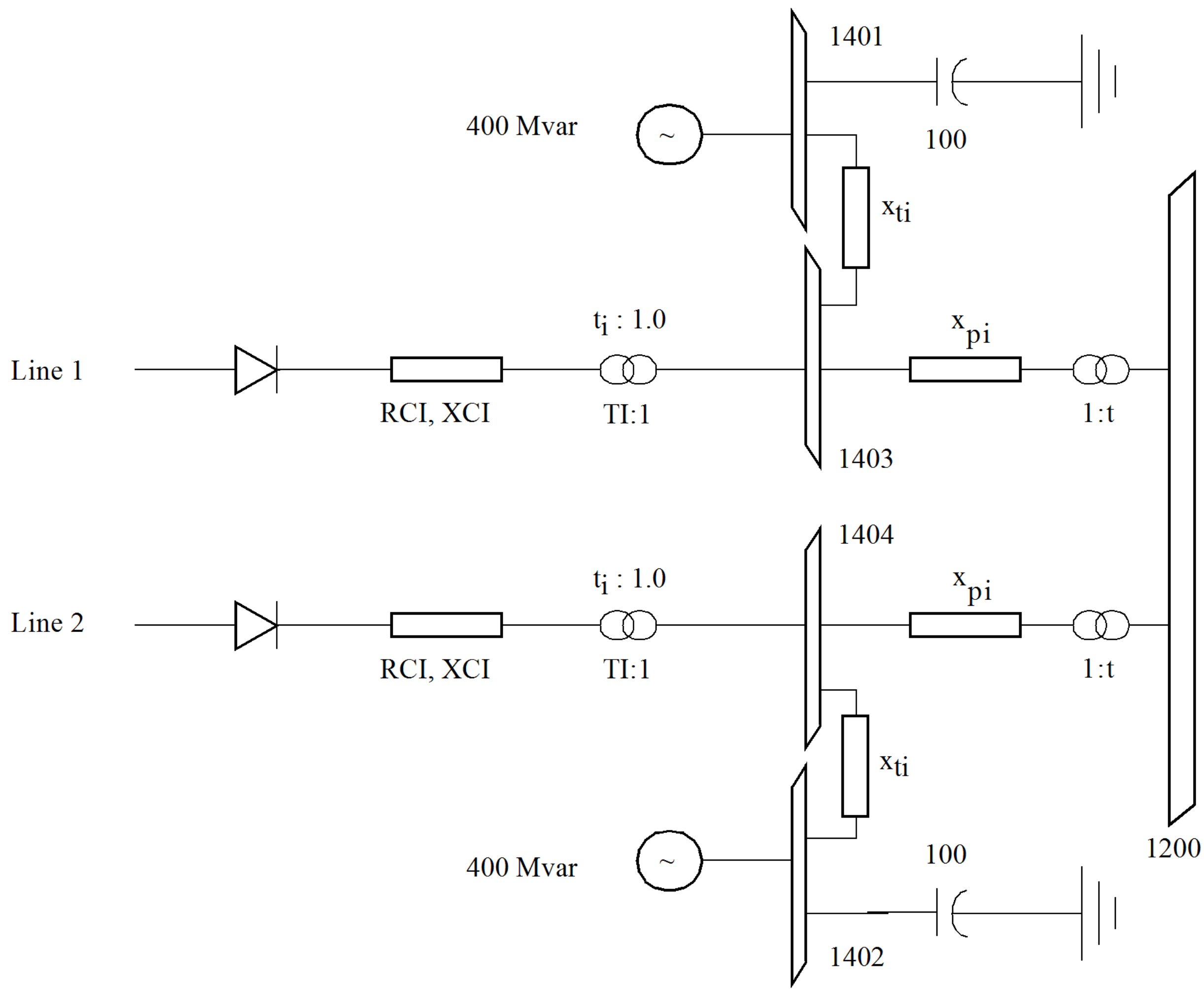


Figure 6.59. Inverter Station Arrangement with Tertiary Connected Synchronous Condensers

Rectifier Transformer

A transformer rating of 760 MW at 0.85 power factor is assumed. The rated MVA = 760/0.85 = 890, and the primary line-to-line voltage = 500 kV. The required secondary open-circuit voltage is determined from Equation 6.1, and assumes a zero-commutating drop initially.

$$\frac{V_{dcr}}{N_r} = \frac{3\sqrt{2}}{\pi} E_{acr} \cos\alpha$$

Taking cos α # 1, gives:

$$E_{acr} = \frac{V_{dcr}}{1.35 N_r} = \frac{550}{1.35 \times 2} = 204\text{kV}$$

which must be increased to allow for the commutating drop.

If E_{acr} = 220 kV at nominal tap, then:

$$TRR = \frac{E_{acr}}{EBASE\ R} = \frac{220}{500} = 0.44$$

and base impedance on the dc side:

$$= \frac{E_{acr}^2}{MVA_{base}} = \frac{(220E3)^2}{890E6} = 55.4\ \Omega$$

Transformer reactance is given a 7%; commutating reactance is equal to transformer leakage reactance:

$X_{CR} = 0.07 \times 55.4 = 3.88\ \Omega$

Transformer resistance is assumed to be negligible.

Transformer tap ratio will be allowed to vary ±10% in steps of 0.625%.

TAPMXR

= 1.1

TAPMNR

= 0.9

TSTPR

= 0.00625

Inverter Transformer

The following ratings are assumed:

Primary (ac side)

890 MVA, 230 kV

Secondary (dc side)

890 MVA, 220 kV

Transformer reactances are given on an 890-MVA base as:

XLH

= 0.20 per unit

XHT

= 0.18 per unit

XLT

= 0.09 per unit

and transformer resistances are assumed negligible.

From (4.26) through (4.28), the reactances needed for the three legs of the transformer model are:

$$X_l = \frac{0.2 + 0.09 - 0.18}{2} = 0.055 \text{ per unit}$$

$$X_h = \frac{0.18 + 0.2 - 0.09}{2} = 0.145 \text{ per unit}$$

$$X_t = \frac{0.18 + 0.09 - 0.0.2}{2} = 0.035 \text{ per unit}$$

Both X_h and X_t must be converted to 100-MVA base and entered as power flow transmission branches. Note that the two inverter transformers are in parallel on the ac side. Hence:

$$X_{1403\text{-}1200} = X_{1404\text{-}1200} = \frac{0.145}{2} \times \frac{100}{890} = 0.00815$$

$$X_{1401\text{-}1403} = X_{1402\text{-}1404} = \frac{0.035}{2} \times \frac{100}{890} = 0.00197$$

The dc side winding must be expressed in ohms per transformer. Base impedance on the dc side winding is the same as for the rectifier transformer in this example; hence:

$X_{ci} = 0.055 \times 55.4 = 3.047\ \Omega$

The inverter-converter transformer ratio and the value of *EBASEI* should correspond to the base voltage chosen for the star-point bus. Because an ac transformer connected to the primary side will be used to control the converter, its base voltage is convenient.

EBASE I = 230

$$TRI = \frac{E_{aci}}{EBASE\ I} = \frac{220}{230} = 0.95652$$

The ac transformer branches from buses 1403 to 1200 and 1404 to 1200 are assumed to control voltage. The buses with the synchronous condensers 1401 and 1402 will measure γ . Tap-changer data should be entered for the ac transformer in the dc line data record. Hence:

TAPI

= 1.0

TAPMXI

= 1.1

TAPMNI

= 0.9

TSTPI

= 0.00625

Power Flow Raw Data File Records

The power flow raw data file records for this dc transmission require a group of records for each pole. The required line load is 3000 MW, or 1500 MW per pole.

MDC

= 1

SETVAL

= 1500

The minimum firing and margin angles will be set to:

ALFMIN

= 8°

GAMMIN

= 18°

The scheduled dc voltage will be 525 kV at the line midpoint giving:

VSCHED

= 525

RCOMP

= RDC/2 = 8.2/2 = 4.1 Ω

The remaining line control parameters will be set as:

ALFMAX

= 12°

GAMMAX

= 20°

VCMODE

= 400 kV

The complete dc transmission data records are shown in Figure 6.60, "Data Records for dc Lines 1 and 2 Representing Transmission System of Figure 6.57, "Sample dc Transmission Line"".

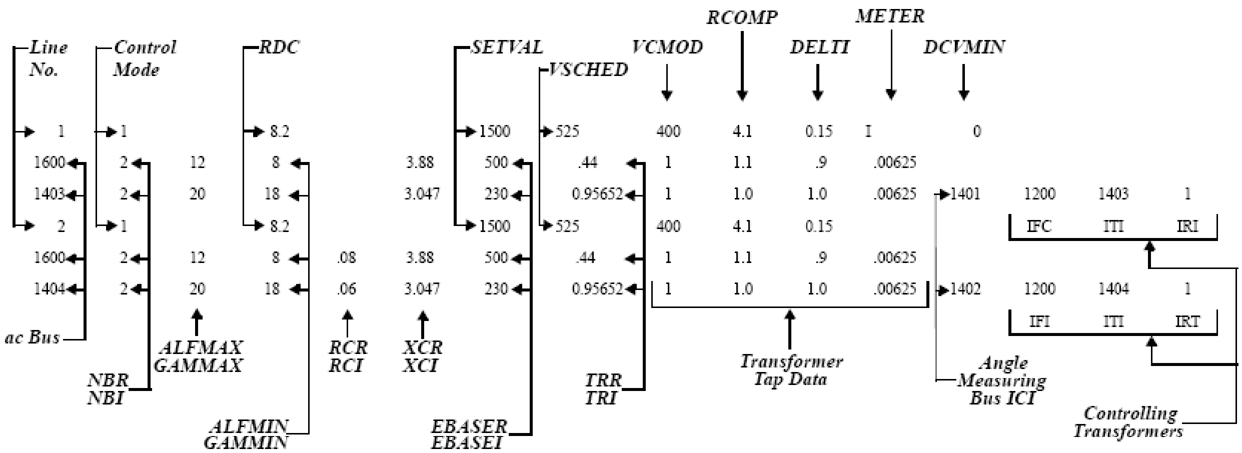


Figure 6.60. Data Records for dc Lines 1 and 2 Representing Transmission System of Figure 6.57, "Sample dc Transmission Line"

6.9.8. FACTS Devices

Several products centered around voltage sourced inverters have been developed based on the U.S. Electric Power Research Institutes (EPRI) Flexible ac Transmission System (FACTS) initiative. These devices are being studied and installed for their fast and accurate control of the transmission system voltages, currents, impedance and power flow. They are intended to improve power system performance without the need for generator rescheduling or topology changes. These devices are available because of the fast development of power electronic devices, specifically gate-turn-off semiconductors.

PSS®E allows for up to fifty FACTS devices to be modeled. Devices that can be modeled are the static synchronous condenser or compensator (STATCON or STATCOM), the static series synchronous condenser (SSSC) and the unified power flow controller (UPFC). An interline power flow controller (IPFC) may be modeled using two consecutively numbered series FACTS devices.

In the power flow the device's physical constraints and a simple power, var, and voltage control are modeled. Using this model as a basis, a variety of more complex, custom made, higher level controls may be represented by PSS®E users using IPLAN. A brief description of the features of the UPFC model follows:

The FACT's model figure has a series element that is connected between two buses and a shunt element that is connected between the sending end bus and ground. One or both of these elements may be used depending upon the type of device. If both elements are used they may or may not exchange active power again depending upon the kind of device being modeled.

In unconstrained operation the series element is used to maintain the desired active and reactive power flow between the sending bus and terminal bus and the shunt element maintains the desired sending end voltage magnitude.

Several constraints come into play that may affect the device's ability to maintain the desired active and reactive power flow. These are:

- Maximum series voltage magnitude.

- Maximum series current magnitude.
- Maximum terminal voltage.
- Minimum terminal voltage.
- Maximum power, which may be transferred between the shunt connected bridge and series connected bridge.

If one of these constraints is active, var flow is abandoned and the real power is maintained at the desired level if possible. If the desired level of real power cannot be held, real power flow control is abandoned and desired reactive power flow is held. If two of these constraints are active, they determine both the power and var flow.

By properly selecting the data different device types and control options can be represented. A SSSC can be represented by setting the maximum bridge power transfer to zero and the maximum shunt current to zero. Terminal voltage can be controlled instead of var flow if the maximum and minimum terminal voltage limits are set equal to the desired level of the terminal voltage. Power flow can be maximized (minimized) if the desired power is set very high (low). A STATCON can be represented by setting the terminal bus number to zero. Data supplied for the different FACTS devices is summarized in Table 6.13, “FACTS Device Type of Data Control”. Control options for SSSC and UPFC are shown in Table 6.14, “Data Entry for Optional Control Settings for UPFC and SSSC Devices”.

Table 6.13. FACTS Device Type of Data Control

Device	Maximum Bridge Power Transfer (TRMX)	Maximum Shunt Current (SHMX)	Terminal (J)
UPFC	>0.	>0.	>0
SSSC	=0.	=0.	>0
STATCON	=0.	>0.	=0

Table 6.14. Data Entry for Optional Control Settings for UPFC and SSSC Devices

Control	Data Setting
var flow (QDES)	Maximum terminal voltage (VTMAX) > minimum terminal voltage (VTMN)
Terminal voltage	Maximum terminal voltage (VTMX) = minimum terminal voltage (VTMN)
Maximize power transfer	Set desired power (PDES) to a large value

The var output of the shunt element is varied to maintain the desired sending end bus voltage magnitude. Current in the shunt connected bridge depends upon its var output and the amount of power transferred to the series connected element. The maximum current limit can therefore be enforced either by first reducing the power transferred to the series element (thus abandoning series power flow control, series var flow, or terminal voltage control depending upon what other limits are active) or by first reducing the shunt var output (thus abandoning sending end voltage control). There are good arguments for both strategies. The model assumes that the shunt var output will be curtailed first when a shunt current is encountered.

Figure 6.61, “UPFC Model” shows the UPFC model with many of its limits. Table 6.15, “FACTS Control Device Data” lists the data.

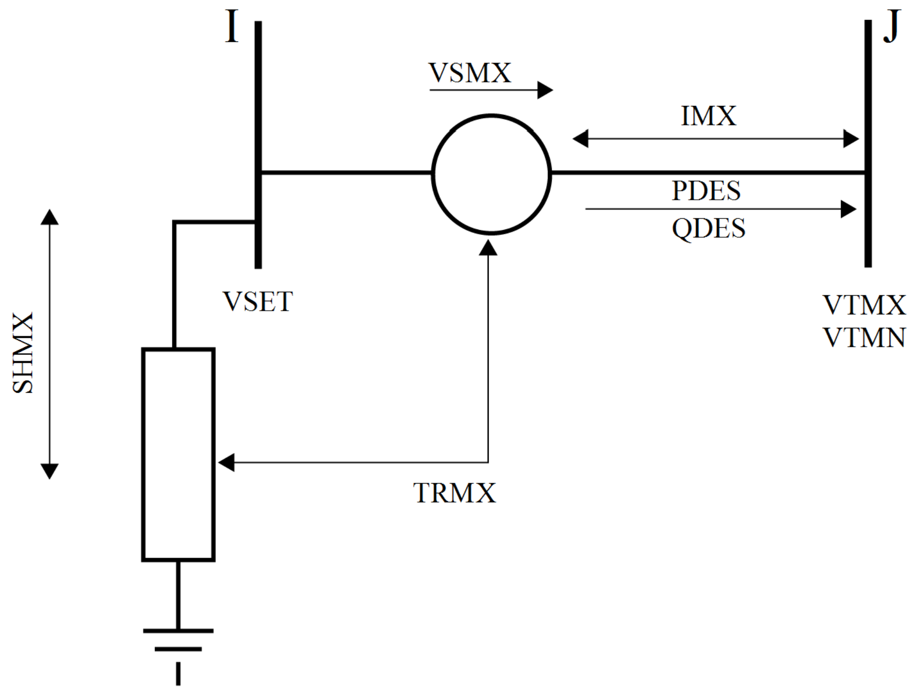


Figure 6.61. UPFC Model

Table 6.15. FACTS Control Device Data

N	FACTS control device number (1 to 50)
I	Sending end bus number
J	Terminal end bus number (0 for a STATCON)
MODE	Control mode: (default is 1) 0 for out-of-service 1 for in-service 2 for series link bypassed with shunt link operating as a STATCON 3 for series and shunt links operating with series link at constant series impedance 4 for series and shunt links operating with series link at constant series voltage 5 for master device of an IPFC with P+Q setpoints specified; FACTS device N+1 must be the slave device of this IPFC

	6 for slave device of an IPFC with P+Q setpoints specified; FACTS device N-1 must be the master device of this IPFC 7 for master device of an IPFC with constant series voltage setpoints specified 8 for slave device of an IPFC with constant series voltage setpoints specified
PDES	Desired real power flow arriving at the terminal end bus in MW (default 0.0)
QDES	Desired reactive power flow arriving at the terminal end bus in Mvar (default 0.0)
VSET	Voltage setpoint at the sending end bus in pu (default 1.0)
SHMX	Maximum shunt current at the sending end bus in MVA at unity voltage (default 9999.)
TRMX	Maximum bridge real power transfer in MW (default 9999.)
VTMN	Minimum voltage at the terminal end bus in pu (default 0.9)
VTMX	Maximum voltage at the terminal end bus in pu (default 1.1)
VSMX	Maximum series voltage in pu (default 1.0)
IMX	Maximum series current in MVA at unity voltage (default 0.0)
LINX	Reactance of the dummy series element used in certain solution states in pu (default 0.05)
RMPCT	Percent of the total Mvar required to hold the voltage at bus I that are to be contributed by the shunt element of this FACTS device.
OWNR	Owner number
SET1, SET2	If MODE is 3, the resistance and reactance respectively of the constant impedance, entered in pu. If MODE is 4, the magnitude (in pu) and angle (in degrees) of the constant series voltage with respect to the quantity indicated by VSREF. If MODE is 7 or 8, the real (Vd) and imaginary (Vq) components (in pu) of the constant series voltage with respect to the quantity indicated by VSREF. For all other MODE values, SET1 and SET2 is not used.
VSREF	Series voltage reference code to indicate the series voltage reference of SET1 and SET2 when MODE is 4, 7 or 8.

	VSREF is 0 for sending end voltage, 1 for series current (0 by default).

The convergence properties of the power flow solution in the presence of several of the above model states is improved by the temporary insertion into the network ac series and shunt elements and a corresponding Norton current injection at the sending and terminal end buses of the FACTS device. The insertion and removal of these dummy elements is handled automatically by the FACTS model using the reactance specified as LINX. When the shunt element is a current limit, and therefore the sending end voltage magnitude is changing from one iteration to the next, slow network convergence may be observed. Manually adjusting LINX can improve the convergence characteristics.

6.9.9. Multiterminal dc Networks

General Considerations

A high-voltage dc (HVDC) system, incorporating more than two terminals, is defined as a multiterminal HVDC system. PSS®E allows for up to 20 multiterminal HVDC systems. Each of these networks can have as many as 12 converters, 20 dc buses and 20 dc links. The PSS®E multiterminal dc network can be used to model either a single pole or both poles. The converter stations used in the PSS®E program must be connected in parallel allowing only meshed and radial systems to be modeled. On each pole a single voltage-controlling inverter must be selected. Figure 6.62, “Direct Current (dc) Network Systems” shows examples of one pole of some four-terminal systems. Figure 6.63, “Two-Pole Multiterminal System” shows an example of two poles of a six-terminal system with a metallic connection between converters to ground.

The converter equations used for the converters of the multiterminal system are the same as those used for the two-terminal modeling listed in the section called “Direct Current Constraint Equations” i.e., Equation 6.1 through Equation 6.2. The program knows whether a converter is a rectifier or an inverter by the sign of SETVAL, the converter setpoint. SETVAL should be entered as a positive power or current for rectifiers and as a negative power or current for inverters. The program will automatically handle the proper direction of currents based on the value of CNVCOD, the converter code, which defines whether a converter is on the positive pole (a value of +1) or negative pole (a value of –1). At the voltage-controlling inverters, a positive value of SETVAL should be entered.

The terminal arrangement represented in the multiterminal model is the same as that used for the two-terminal of Figure 6.53, “A dc Terminal Arrangement in Absence of Tertiary-Connected Reactive Supply or Filtering Equipment”. Bridge firing angle and transformer tap position are adjusted by the power flow solution logic to control dc voltage and current (power).

The operation of the converter controls resembles that of the two-terminal model, but has been slightly modified. The literature refers to this control method as either Current Margin Method or Constant Current Method, where, normally, one converter per pole regulates voltage (or its angle) and the remaining regulate their current. The basic relationship for a four-terminal system with an inverter controlling voltage is illustrated in terms of dc voltage versus dc current characteristics in Figure 6.64, “Normal Operating Condition”, where ac voltages are near normal. In this normal case, the firing angle of an inverter would be adjusted to maintain the specified dc voltage, SETVAL.

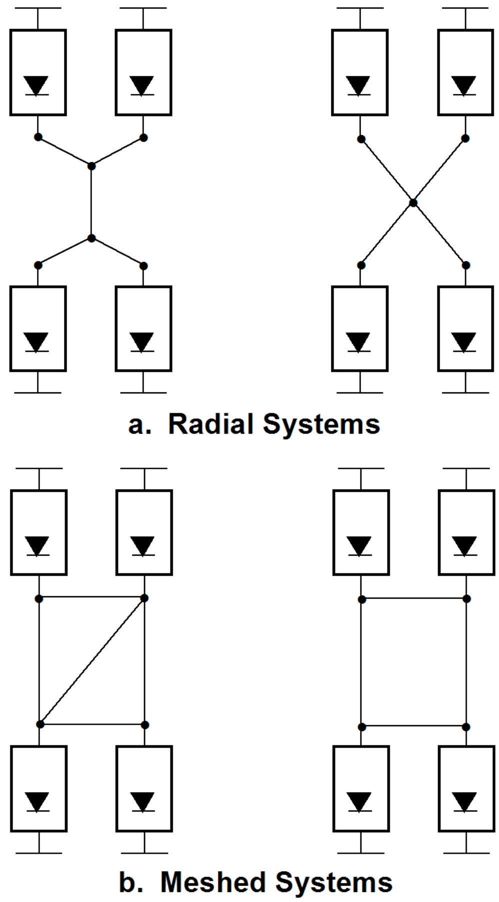


Figure 6.62. Direct Current (dc) Network Systems

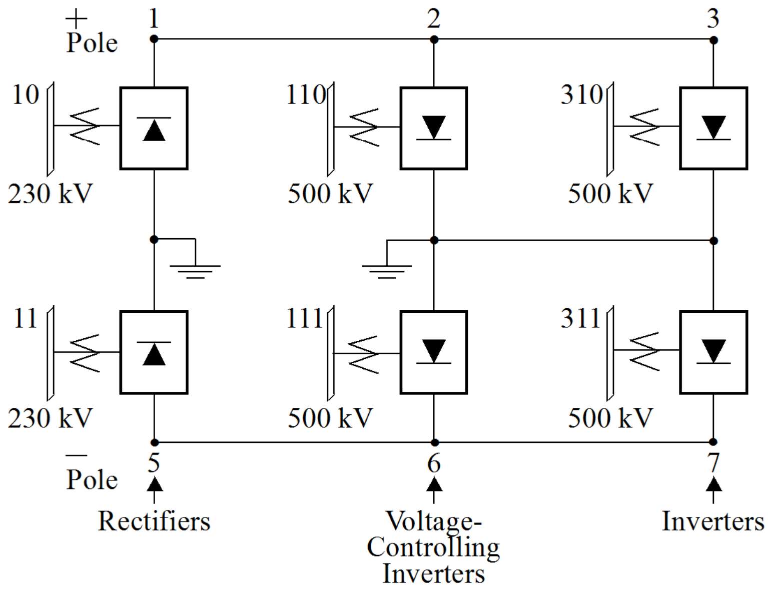


Figure 6.63. Two-Pole Multiterminal System

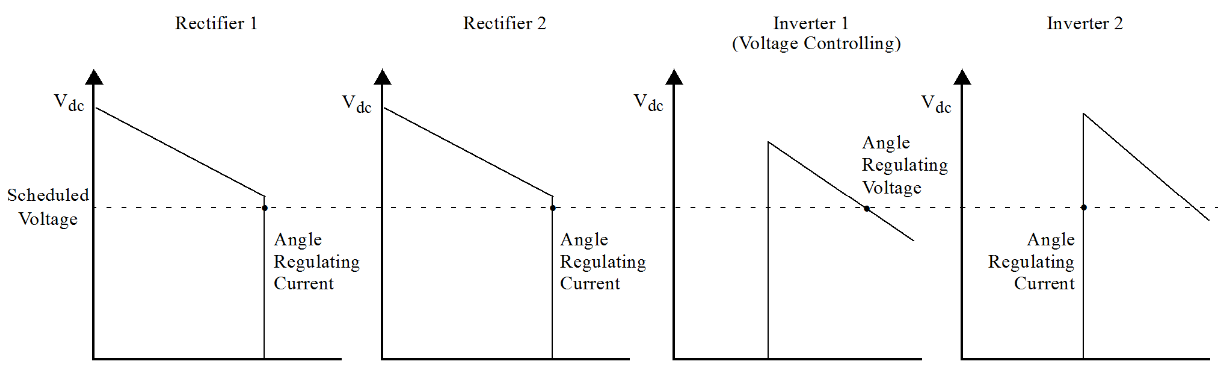


Figure 6.64. Normal Operating Condition

For each rectifier in the multiterminal dc system, the user may specify a current deviation. This deviation defines the change in converter current (power) that PSS®E will allow if the converter reaches a control angle limit and cannot maintain its scheduled current. Many proposed dc schemes require some type of central coordinator where the function would be to redistribute power for a reduction due to occurrences of ac voltage problems. PSS®E allows the user to model this by specifying converter participation factors, DCPF. Current or power is redistributed among all converters that are not at minimum angle. The philosophy behind the PSS®E modeling is that communication is available in the steady state. To represent cases where the communication is not available, the user should enter new appropriate SETVALs, MARGNs, and DCPFs. Figure 6.65, “Low ac Voltage at Rectifier” shows the dc voltage versus dc current characteristics when one rectifier has its ac voltage depressed. Intermediate ac voltages can cause operation at voltages between desired current and deviation currents. If this occurs, the rectifier will make as much current as possible and the difference between desired current and resulting current is redistributed.

In several proposed multiterminal schemes, a margin current (a current smaller than the sum of currents at all other terminals) is specified at the voltage controlling inverter. In the case of voltage depression at a rectifier, current control will be maintained at the rectifier until a current at the rectifier is such that the sum of currents is greater than the current specified for the voltage-controlling converter. If current drops sufficiently, the voltage-controlling converter takes over current control (a mode shift) and the rectifier determines the dc voltage. This scheme can be modeled in PSS®E by specifying the DCPFs of all converters except the voltage controlling to zero. The MARGN value of each rectifier should be set to the difference between the sum of currents desired and converter voltage-controlling current desired divided by the desired rectifier current.

For the multiterminal dc line, the HVDC system can be instructed to hold either desired currents or desired power. Control of power is maintained as long as the magnitude of dc voltage at every inverter exceeds a value specified as VCMOD. If an inverter voltage falls below this value when the line is specified to be in power control, each converter current is controlled to:

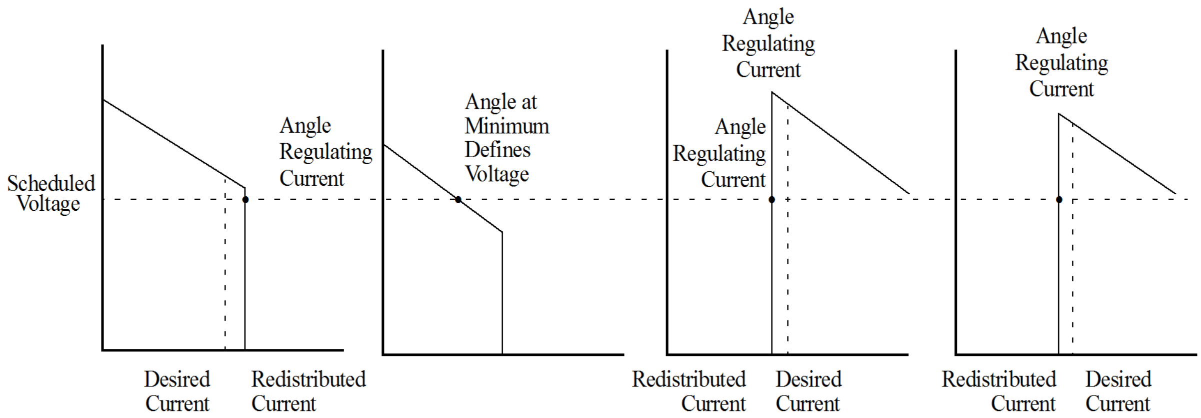
$$\text{idc} = \frac{\text{Desired Power}}{\text{Scheduled dc Voltage}}$$

leaving the actual dc received power to fall in proportion to the dc voltage. The logic in the program also switches to constant current control independent of the value of VCMOD if low ac voltage at a rectifier causes a current reversal at minimum angle.

If the multi-terminal dc line is in current control mode and the ac voltage is low enough to cause a current reversal, the line will be blocked.

Tapping logic at each converter is identical to that of the two-terminal model, i.e., taps adjusted to hold bridge firing angles above minimum and below maximum with minimums being absolute values and maximum being objectives. The user may lock the taps during solution if the OPT suffix is specified.

The multiterminal HVDC systems are an integral part of the power flow working case. The standard PSS®E reports (POUT, DRAW, etc.) all show the flow from the dc buses into the converters. A special report obtained by activity MTDC lists flows within the dc network. For the purposes of reporting, metering is assumed on the dc side of the converter. Each dc bus is assigned to an area and each dc branch is given a metered end for use in area interchange adjustment and reporting.



$$\text{Redistributed Current}_i = \text{Desired Current}_i + \text{DCPF}_i \times \text{MARGIN}_j / \sum_{\text{exclude}_j} \text{DCPF}$$

j is rectifier at minimum

Figure 6.65. Low ac Voltage at Rectifier

Multiterminal Data

All multiterminal HVDC data are entered via activities READ, RDCH, and Reading Power Flow Data Additions from the Terminal. All data specified may be changed by activities CHNG or RDCH. General data is the first set of data that must be entered for each multiterminal system. The definition of the data is as follows:

NCONV

Number of ac converter stations

NDCBS

Number of dc buses in this network

NDCLN

Number of dc links in this network

MDC

dc line control mode 0 = blocked line 1 = constant power 2 = constant current

VCONV

Bus number or extended bus name of ac converter station that controls voltage of positive pole

VCMOD

Magnitude of minimum dc voltage at all inverters for power control mode (kV)

VCONVN

Bus number or extended bus name of ac converter station that controls voltage of negative pole (may be zero if negative pole not represented)

The second set of specified data is the converter data, which is a subset to the converter data specified for the two-terminal line (the section called "Direct Current Line Data "through the section called "Optional Direct Current Terminal Line Logic"). This data is as follows:

TR

Actual open-circuit voltage ratio (i.e., nominal turns ratio), for line-to-line voltages on primary and secondary of converter transformer. Secondary voltage is divided by primary voltage.

TAP

Per-unit variation of actual voltage ratio from nominal voltage, due to offnominal tap setting, with taps assumed to be on primary winding.

NB

Number of three-phase converter bridges in series, with respect to the dc side of converter.

EBAS

Line-to-line base rms voltage at primary ac system bus (kV).

XC, RC

Converter transformer secondary commutating impedance in ohms per bridge (see the section called "Optional Direct Current Terminal Line Logic").

ANGMN

Minimum firing (delay) angle of rectifier or minimum margin angle of inverter in degrees.

ANGMX

Maximum firing (delay) angle objective for rectifier or maximum margin angle objective for inverter in degrees.

TPMX

Maximum value of converter transformer tap ratio (pu).

TPMN

Minimum value of converter transformer tap ratio (pu).

TSTP

Converter transformer tap-step (pu).

SETVAL

Desired dc power (MW) or desired dc current (A). Positive value for rectifier, negative value for inverter. For the voltage-controlling bus, scheduled dc voltage magnitude in kV.

MARGN

Rectifier current deviation, per-unit value of desired dc power or current.

DCPF

Converter participation factor. When the current order at any rectifier is reduced, current orders of remaining converters are modified in proportion by these factors.

CNVCOD

Positive value converters on positive pole; negative value converters on negative pole.

For each multiterminal HVDC system, the user must also specify the configuration of the HVDC network with two sets of records. First, in each system, the dc buses must be specified with the following data.

IDC

The dc bus number. The buses must be numbered sequentially starting with 1, although the records can be entered in random order. All buses must be specified as an IDC bus even if they were previously or will subsequently be specified as an IDC2 bus.

IB

The ac converter bus number or extended bus name, or zero. Each ac converter bus must be specified as IB in exactly one dc bus record. Some dc buses may not be connected to an ac bus.

IA

Area number

ZONE

Zone number

'BUS NAME'

Name of dc bus, up to twelve characters

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 SETVAL 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 that have IB specified as zero. IDC2 = 0 by default.

RGRND

Resistance to ground at bus IDC entered in ohms. This value is ignored if IDC was not specified as an IDC2 bus.

Secondly, the dc link records must be specified as follows:

IDC

Branch from bus dc bus number

JDC

Branch to bus dc bus number, entered as negative number to designate it as the metered end

DCCKT

One character dc link circuit identifier. DCCKT = '1' by default

RDC

dc link resistance (Ω). No default allowed

LDC

dc link inductance (mH). This value is not used by the power flow, but is available to multiterminal dc line dynamics models. LDC = 0.0 by default

Each multiterminal HVDC converter appears to the ac system as current injection. These current injections are calculated and applied during the power flow solutions at the converter ac buses. (As for the two-terminal model, the converter ac buses should not have any load on them because the current injections are applied as loads during solution.)

During each power flow solution, the logic calculates and places the following items in the power flow working files:

PAC,QAC

The power and vars drawn by the dc converter (MVA)

ALF/GAM

Rectifier delay angle or inverter margin angle (°)

VDC

dc bus voltage (V)

TAP

Off-nominal tap settings (pu)

Multiterminal Setup Examples

As an example of a multiterminal dc line data setup, consider the single pole HVDC system shown in Figure 6.66, “Sample Four-Terminal System”. Data calculation for converters is identical to that of the two-terminal examples shown in the section called “Example of Direct Current Line Setup”. Data required for this line would be in the format shown in Figure 6.67, “Multiterminal Example Data”.

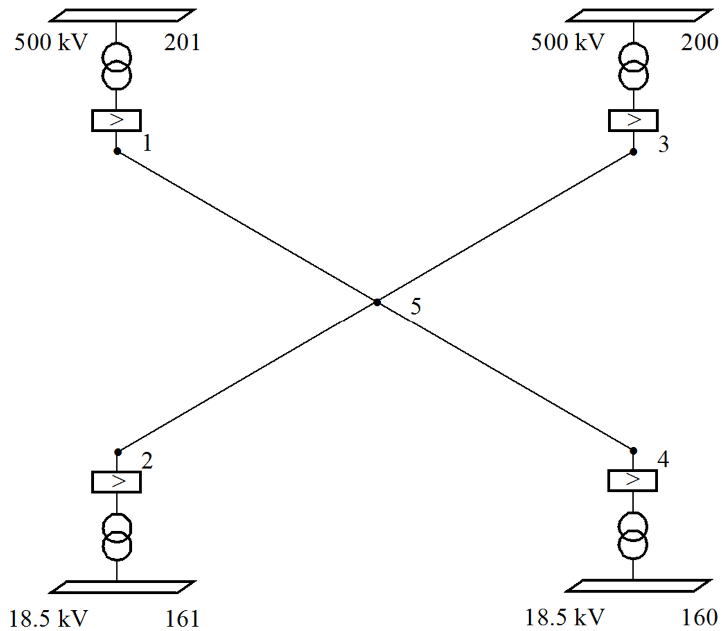


Figure 6.66. Sample Four-Terminal System

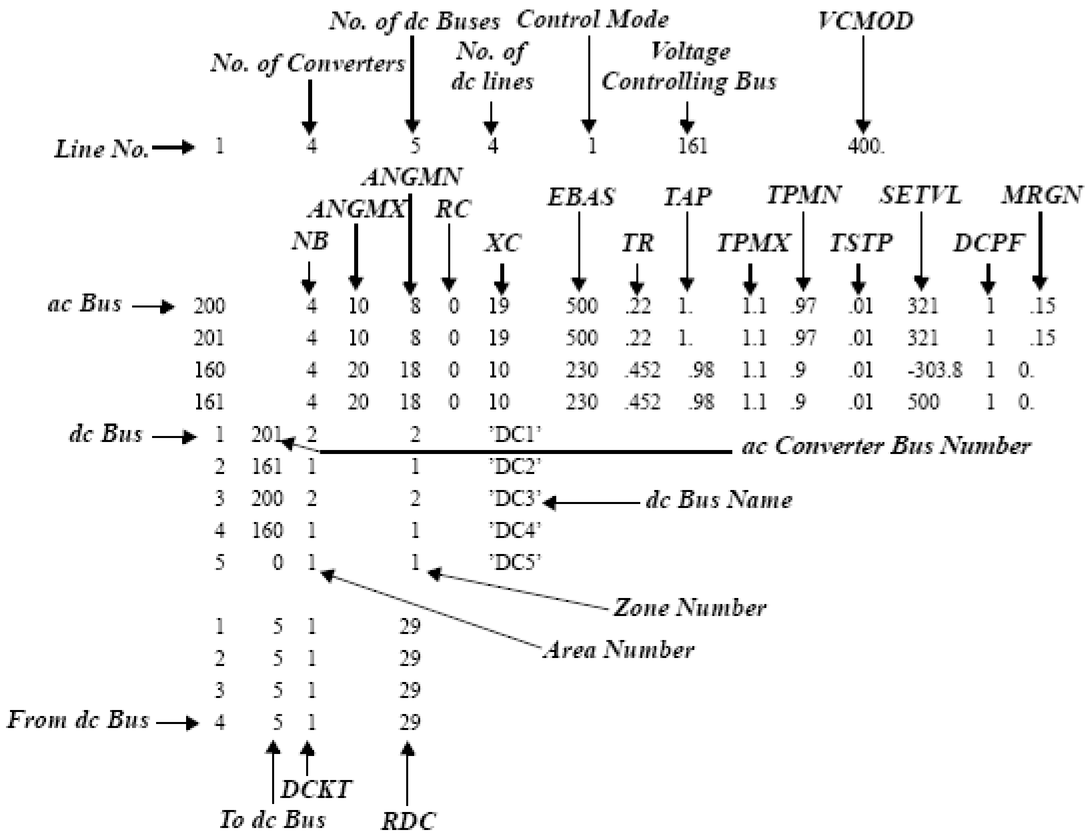


Figure 6.67. Multiterminal Example Data

The resulting report listing that output for each of the converters is shown in Figure 6.68, “Base Case Output Showing Converters of Multiterminal dc Network”. Note that for this case all ac voltages were near normal so that the dc converter taps and all angles were within range. The solution of the dc network is shown in Figure 6.69, “HVDC Network Solution Report”. Figure 6.70, “Converter Output with Redistribution of Power Caused by Low ac Voltage” shows that low ac voltage at one rectifier caused redistribution of power. The distribution factors in this case were all equal. Figure 6.68, “Base Case Output Showing Converters of Multiterminal dc Network” and Figure 6.70, “Converter Output with Redistribution of Power Caused by Low ac Voltage” show that the power flowing into the converter has gone from 321.0 MW to 272.9 MW, the 15% specified deviation. Inspection of all the other converters will show that each changed by 16 MW because all distribution factors were equal.

Data entry for the bipole shown in Figure 6.63, “Two-Pole Multiterminal System” is tabulated in Figure 6.71, “Data Input for a Bipole”. Note that the dc link at dc bus 4 connected to the center of the two voltage-controlling converters is represented in the data simply as a resistance to ground at dc bus 4 because that center point is a ground point. Results of the solution for this case are tabulated in Figure 6.72, “Normal Operating Mode”. The multiterminal dc (MTDC) report prints all voltages with respect to ground, and flows are shown both as amperes and MW.

The resulting report listing the output for each of the converters is shown in Figure 6.68, “Base Case Output Showing Converters of Multiterminal dc Network”. Note Figure 6.73, “Mode Switch on Negative Pole” shows the resulting flows when a mode shift occurs because of low ac voltage at the rectifier end of only the negative pole. Current that would flow in the neutral wire between inverters is shown as 23 A to ground at dc bus 4. Negative pole voltages at all converters are depressed, while positive pole voltages are near normal.

Figure 6.68. Base Case Output Showing Converters of Multiterminal dc Network

```
     PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS®E      THU JUN 28, 1990  13:47
PSS®E PROGRAM APPLICATION GUIDE EXAMPLE                          MULTI-TERMINAL
BASE CASE INCLUDING SEQUENCE DATA                                   DC LINE 1

       BUS X-- NAME --X AREA ZONE CKT     MW      AMPS      KV
FROM     1 DC1      (DC)    2    2                        534.60
  TO   201 HYDRO     500    2    2      -321.0   -600.4
  TO     5 DC5      (DC)    1    1   1   321.0    600.4

       BUS X-- NAME --X AREA ZONE CKT     MW      AMPS      KV
FROM     2 DC2      (DC)    1    1                        500.00
  TO   161 INVJCT   18.0    1    1       296.4    592.8
  TO     5 DC5      (DC)    1    1   1  -296.4   -592.8

       BUS X-- NAME --X AREA ZONE CKT     MW      AMPS      KV
FROM     3 DC3      (DC)    2    2                        534.60
  TO   200 HYDRO     500    1    1      -321.0   -600.4
  TO     5 DC5      (DC)    1    1   1   321.0    600.4

       BUS X-- NAME --X AREA ZONE CKT     MW      AMPS      KV
FROM     4 DC4      (DC)    1    1                        499.55
  TO   160 INVJCT   18.0    1    1       303.8    608.1
  TO     5 DC5      (DC)    1    1   1  -303.8   -608.1

       BUS X-- NAME --X AREA ZONE CKT     MW      AMPS      KV
FROM     5 DC5      (DC)    1    1                        517.19
  TO     1 DC1      (DC)    2    2   1  -310.5   -600.4
  TO     2 DC2      (DC)    1    1   1   306.6    592.8
  TO     3 DC3      (DC)    2    2   1  -310.5   -600.4
  TO     4 DC4      (DC)    1    1   1   314.5    608.1
```

Figure 6.69. HVDC Network Solution Report

Figure 6.70. Converter Output with Redistribution of Power Caused by Low ac Voltage

Figure 6.71. Data Input for a Bipole

```
     PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS®E      FRI JUN 15, 1990  14:13
TEST CASE                                                        MULTI-TERMINAL
2 REC,4 INVERTERS                                                   DC LINE 1

       BUS X-- NAME --X AREA ZONE CKT      MW      AMPS       KV
FROM     1 REC1 DC (DC)    1   10                            982.05
  TO    10 REC 1     230   1   10      -1000.0  -1018.3
  TO     2 INV1 DC (DC)    1   10   1   1000.0   1018.3

       BUS X-- NAME --X AREA ZONE CKT      MW      AMPS       KV
FROM     2 INV1 DC (DC)    1   10                            979.00
  TO   110  INV 1    500   1   10        496.1    506.7
  TO     1 REC1 DC (DC)    1   10   1   -996.9  -1018.3
  TO     3 INV3 DC (DC)    5   50   1    500.8    511.5

       BUS X-- NAME --X AREA ZONE CKT      MW      AMPS       KV
FROM     3 INV3 DC (DC)    5   50                            977.47
  TO   310 INVERT1   500   5   50        500.0    511.5
  TO     2 INV1 DC (DC)    1   10   1   -500.0   -511.5

       BUS X-- NAME --X AREA ZONE CKT      MW      AMPS       KV
FROM     4 MET DC  (DC)    5   50                              0.00
  TO GROUND                                0.0      0.0
  TO   310 INVERT1   500   5   50          0.0   -511.5
  TO   311 INVERT4   500   5   50          0.0    511.5

       BUS X-- NAME --X AREA ZONE CKT      MW      AMPS       KV
FROM     5 REC2 DC (DC)    4   50                           -982.05
  TO    11 REC 2     230   5   50      -1000.0   1018.3
  TO     6 INV6 DC (DC)    3   50   1   1000.0  -1018.3

       BUS X-- NAME --X AREA ZONE CKT      MW      AMPS       KV
FROM     6 INV6 DC (DC)    3   50                           -979.00
  TO   111 INVERT3   500   5   50        496.1   -506.7
  TO     7 INV4 DC (DC)    3   50   1    500.8   -511.5
  TO     5 REC2 DC (DC)    4   50   1   -996.9   1018.3

       BUS X-- NAME --X AREA ZONE CKT      MW      AMPS       KV
FROM     7 INV4 DC (DC)    3   50                           -977.47
  TO   311 INVERT4   500   5   50        500.0   -511.5
  TO     6 INV6 DC (DC)    3   50   1   -500.0    511.5
```

Figure 6.72. Normal Operating Mode

```
     PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS®E      FRI JUN 15, 1990  14:14
TEST CASE                                                        MULTI-TERMINAL
2 REC,4 INVERTERS                                                   DC LINE 1

       BUS X-- NAME --X AREA ZONE CKT       MW       AMPS      KV
FROM     1 REC1 DC (DC)     1   10                           982.05
  TO    10 REC 1     230    1   10       -1000.0   -1018.3
  TO     2 INV1 DC (DC)     1   10   1    1000.0    1018.3

       BUS X-- NAME --X AREA ZONE CKT       MW       AMPS      KV
FROM     2 INV1 DC (DC)     1   10                           979.00
  TO   110  INV 1    500    1   10         496.0     506.7
  TO     1 REC1 DC (DC)     1   10   1    -996.9   -1018.3
  TO     3 INV3 DC (DC)     5   50   1     500.8     511.6

       BUS X-- NAME --X AREA ZONE CKT       MW       AMPS      KV
FROM     3 INV3 DC (DC)     5   50                           977.47
  TO   310 INVERT1   500    5   50         500.1     511.6
  TO     2 INV1 DC (DC)     1   10   1    -500.1    -511.6

       BUS X-- NAME --X AREA ZONE CKT       MW       AMPS      KV
FROM     4 MET DC  (DC)     5   50                             0.12
  TO GROUND                                  0.0      23.2
  TO   310 INVERT1   500    5   50          -0.1    -511.6
  TO   311 INVERT4   500    5   50           0.1     488.4

       BUS X-- NAME --X AREA ZONE CKT       MW       AMPS      KV
FROM     5 REC2 DC (DC)     4   50                          -925.62
  TO    11 REC 2     230    5   50        -900.0     972.3
  TO     6 INV6 DC (DC)     3   50   1     900.0    -972.3

       BUS X-- NAME --X AREA ZONE CKT       MW       AMPS      KV
FROM     6 INV6 DC (DC)     3   50                          -922.70
  TO   111 INVERT3   500    5   50         446.5    -483.9
  TO     7 INV4 DC (DC)     3   50   1     450.7    -488.4
  TO     5 REC2 DC (DC)     4   50   1    -897.2     972.3

       BUS X-- NAME --X AREA ZONE CKT       MW       AMPS      KV
FROM     7 INV4 DC (DC)     3   50                          -921.24
  TO   311 INVERT4   500    5   50         449.9    -488.4
  TO     6 INV6 DC (DC)     3   50   1    -449.9     488.4
```

Note low voltage

Figure 6.73. Mode Switch on Negative Pole

Chapter 7

System Manipulation and Monitoring

7.1. Activity CNTB

Often when doing studies of Mvar placement, and especially when a study of different system loadings (heavy versus light) are being done, the voltage setpoints or bands on controlling equipment must be modified. This job can be very tedious and is very error prone if the user must specify each piece of equipment individually. Activity CNTB facilitates the process by displaying all generator, switched shunts, and transformers controlling the voltage at a specified bus and allowing the user, by entering a single value, to change the bands and setpoints of all the devices.

7.2. Activity ECDI

Activity ECDI is designed to be an actual economic dispatch which takes into consideration unit limits, fuel costs, and heat rates for individual units. The activity helps the planning engineer either in setting up a base case for the future or in studying a system in which several equipment outages have occurred. Activity ECDI dispatches the units somewhat economically, and also commits units based on a priority list entered by the user. First priority is given to those units with the lowest full-load average cost per MW. This activity does not take into consideration system losses. The user specifies the generation to be dispatched and how much excess generation should be online (spinning reserve). After running activity ECDI, the user can solve the case, get an accurate picture of losses, and then redispatch as desired.

Figure 7.1, "Dispatching Units with Activity ECDI" shows how the user would first reduce load by SCAL (See Section 7.4, "Activity SCAL") and run ECDI to commit and redispatch units in the entire system to create a light load case from a heavy load case.

```
ACTIVITY? scal,all

 LOAD-MW GENERATION   SHUNT-MW   REACTORS CAPACITORS
  3200.0      3248.9       0.0     -900.0       550.0

ENTER 0 FOR NO CHANGE
      1 TO SPECIFY NEW TOTAL POWERS
      2 TO SPECIFY PERCENT CHANGES: 1

ENTER NEW TOTALS FOR
LOAD, GENERATION, SHUNT-MW, REACTOR-MVAR (NEG), CAPACITOR-MVAR:
2000                                                                      Scale loads to 2000 MW
TOTAL GENERATOR LIMITS: PMAX =    59994.0  PMIN =   -59994.0
ENTER 1 TO ENFORCE MACHINE POWER LIMITS:

TOTAL LOAD MVAR = 1950.0. ENTER CHANGE CODE:
 0 FOR NO CHANGE         1 FOR CONSTANT P/Q RATIO
 2 FOR NEW TOTAL Q LOAD  3 FOR PERCENT CHANGE
 4 FOR NEW POWER FACTOR: 1                                                Mvar load scaled
                                                                          at same P/Q ratio
NEW: LOAD-MW  LOAD-MVAR GENERATION   SHUNT-MW   REACTORS CAPACITORS
      2000.0     1218.8     3248.9        0.0     -900.0       550.0

ACTIVITY? ecdi all
ENTER UNIT DISPATCH DATA FILE NAME: savnw.ecdi

ENTER 0 TO START FROM CURRENT COMMITMENT PROFILE
      1 FOR NEW COMMITMENT PROFILE: 1                                     Redispatch units
                                                                          starting from scratch
PRE-DISPATCH PRODUCTION COST IS      0.00 $/HR

PRESENT TOTAL GENERATION OF UNITS BEING DISPATCHED IS       0.000
MAXIMUM GENERATION OF DISPATCHED UNITS NOW ON-LINE IS       0.000
MINIMUM GENERATION OF DISPATCHED UNITS NOW ON-LINE IS       0.000

PRESENT GENERATION OF SUBSYSTEM BEING DISPATCHED IS         0.000

ENTER DESIRED LOAD, DESIRED MINIMUM CAPACITY OF UNITS BEING DISPATCHED
2030 2200

BUS   101 [NUC-A   21.6] MACHINE 1 PRIORITY  1 ON-LINE. COST =    5.03 $/MW-HR

BUS   201 [HYDRO    500] MACHINE 1 PRIORITY  1 ON-LINE. COST =    6.24 $/MW-HR
  1     -58.057        6.810        1.47000
  2     289.077        8.280        0.73500
  3     198.615        7.545        0.36750
  4      87.721        7.177        0.18375
  5      14.832        6.994        0.09188
  6     -21.613        6.902        0.04594
  7      -3.390        6.948        0.02297
  8       5.721        6.971        0.01148
  9       1.165        6.959        0.00574
 10      -1.112        6.954        0.00287
 11       0.027        6.956        0.00144
 12      -0.543        6.955        0.00072
 13      -0.258        6.956        0.00036
 14      -0.116        6.956        0.00018
 15      -0.045        6.956        0.00009
 16      -0.009        6.956        0.00004

REACHED TOLERANCE IN  16 ITERATIONS

TOTAL MISMATCH IS    -0.0092 MEGAWATTS
PRODUCTION COST IS  10012.96 $/HR
INCREMENTAL COST IS     6.96 $/MW-HR

PRESENT TOTAL GENERATION OF UNITS BEING DISPATCHED IS    2029.991
MAXIMUM GENERATION OF DISPATCHED UNITS NOW ON-LINE IS    2500.000
MINIMUM GENERATION OF DISPATCHED UNITS NOW ON-LINE IS     750.000

PRESENT GENERATION OF SUBSYSTEM BEING DISPATCHED IS      2029.991
```

Figure 7.1. Dispatching Units with Activity ECDI

7.3. Activity MODR

The resistance of transmission line conductors is the most important cause of power loss in a transmission line. This resistance is a function of conductor temperature, which, in turn, is a function of line loading, ambient temperature, wind velocity, and amount of sunlight. The variation of resistance of metallic conductors with temperature is linear over the normal range of operation. Activity MODR allows the user to take into consideration permanently these variations in resistance by modifying the resistances, based on the loading in the base case. Users can then resolve the case and hopefully more accurately project losses. Resistances in the working case are modified by the following expression

$$R_{new} = R_o \left(1 + \left(\frac{\text{MVA Flow}}{\text{Rating} \times \text{Percentage Base}} - 1 \right) \times K \right)$$

where

R_o is the resistance in the base case.

MVA flow is the greater MVA measurement taken at both ends of the branch.

Rating and percentage base are user inputs that define the basis of R_o.

K is the scaling factor that modifies the resistance.

For example, a line rated at 1200 MVA, with an impedance of 0.003, is assumed at 60% of the rating. A scaling factor of 0.01 would modify R_o as follows:

at 400 MVA flow to

$$R = 0.003 \left(1 + \left(\frac{400}{1200 \times 0.6} - 1 \right) \times 0.01 \right) = 0.00299$$

and, at 1200 MVA flow to

$$R = 0.003 \left(1 + \left(\frac{1200}{1200 \times 0.6} - 1 \right) \times 0.01 \right) = 0.00302$$

7.4. Activity SCAL

Activity SCAL handles changes of loading over the entire system or over a part of the system. SCAL adjusts all load consumptions, shunt admittances, and generator outputs of a specified group of buses. The group of buses is defined by the same selection criteria used for output reports. These criteria are summarized in Section 6.6.1 Report Selection and Routing. SCAL recognizes the suffixes ALL, AREA, ZONE, OWNER, KV, and OPT. When applied to a group of buses, SCAL multiplies the load or generation value at each bus by the same factor; that is

$$\text{New Bus Load MW} = \text{Old Bus Load MW} \times \frac{\text{New Total Load MW for Group of Buses}}{\text{Old Total Load MW for Group of Buses}}$$

In its normal application, SCAL is applied to system models that *have not* been processed by CONL, but may be applied to a system where loads have been converted by CONL. In this case, the total loads are totals of actual load at present bus voltage; not totals of nominal load. Accordingly, the system must be solved to usable tolerance before using SCAL if CONL has been used previously.

If activity CONL has been run, activity SCAL changes all components of load and the reference load in the same proportion. Note that this does not necessarily mean that the reference load is equal to the sum of the load components (see Section 7.7.2, "Activity CONL").

Figure 7.2, "Two Executions of Activity SCAL to Adjust Load and Generation" shows a sample dialog with activity SCAL. This dialog shows:

- The execution of SCAL with suffix, ZONE, to increase the load in zone 1 from 3000 MW to 3300 MW, leaving the load power factor unchanged at unity.
- The execution of SCAL with the suffix, AREA, to reduce generation in area 1 from 3255 MW to 3000 MW.
- And also in the second execution of SCAL, a change of load in area 3 to 1800 MW and change of load power factor in area 3 from unity to 0.95.

The first step multiplies load MW at all buses in zone 1 by 3300/3000 = 1.11. The second step multiplies generator MW at each generator in area 1 by 2500/2773 = 0.9016. The third step sets the load Mvar at each bus in area 3 to

$\tan(\cos^{-1}0.95) \times \text{load MW} = 0.329 \times \text{load MW}$

Note that the scaling of generation is *not* a dispatch calculation. It does not recognize the characteristics of the generating units (their fuel costs); it simply multiplies generator MW data by the common scaling factor for the area, zone, or other grouping of buses. SCAL does allow the user an option to honor machine real power limits. SCAL also handles motors and generators separately, and bus-connected reactors and capacitors separately.

```
ACTIVITY? SCAL ZONE                                      First adjust zone 1 load
ENTER UP TO 20 ZONE NUMBERS
1

 LOAD-MW GENERATION   SHUNT-MW   REACTORS CAPACITORS
  3000.0     3755.3        0.0        0.0        0.0

ENTER 0 FOR NO CHANGE
      1 TO SPECIFY NEW TOTAL POWERS
      2 TO SPECIFY PERCENT CHANGES: 1                    Enter new total powers

ENTER NEW TOTALS FOR
LOAD, GENERATION, SHUNT-MW, REACTOR-MVAR (NEG), CAPACITOR-MVAR:
3300                                                     New load is 3300 MW
TOTAL GENERATOR LIMITS: PMAX =      4350.0 PMIN =       810.0
ENTER 1 TO ENFORCE MACHINE POWER LIMITS: 0

TOTAL LOAD MVAR =     0.0. ENTER CHANGE CODE:
 0 FOR NO CHANGE          1 FOR CONSTANT P/Q RATIO
 2 FOR NEW TOTAL Q LOAD  3 FOR PERCENT CHANGE
 4 FOR NEW POWER FACTOR: 0                               Leave power factor at unity

NEW: LOAD-MW LOAD-MVAR GENERATION   SHUNT-MW   REACTORS CAPACITORS
      3300.0       0.0     3755.3        0.0        0.0        0.0
ENTER UP TO 20 ZONE NUMBERS
0                                                        No more zone changes

ACTIVITY? SCAL AREA                                      Adjust area generation
ENTER UP TO 20 AREA NUMBERS

 LOAD-MW GENERATION   SHUNT-MW   REACTORS CAPACITORS
     0.0     3255.3        0.0        0.0        0.0

ENTER 0 FOR NO CHANGE
      1 TO SPECIFY NEW TOTAL POWERS
      2 TO SPECIFY PERCENT CHANGES: 1                    Enter new total powers again

ENTER NEW TOTALS FOR
LOAD, GENERATION, SHUNT-MW, REACTOR-MVAR (NEG), CAPACITOR-MVAR:
,3000                                                    New generation
TOTAL GENERATOR LIMITS: PMAX =      3850.0 PMIN =       660.0
ENTER 1 TO ENFORCE MACHINE POWER LIMITS: 0               Ignore real generation limits

TOTAL LOAD MVAR =     0.0. ENTER CHANGE CODE:
 0 FOR NO CHANGE          1 FOR CONSTANT P/Q RATIO
 2 FOR NEW TOTAL Q LOAD  3 FOR PERCENT CHANGE
 4 FOR NEW POWER FACTOR: 0                               No need to change this

NEW: LOAD-MW LOAD-MVAR GENERATION   SHUNT-MW   REACTORS CAPACITORS
         0.0       0.0     3000.0        0.0        0.0        0.0
ENTER UP TO 20 AREA NUMBERS
3                                                        Adjust area 3 load and power factor

 LOAD-MW GENERATION   SHUNT-MW   REACTORS CAPACITORS
  2000.0        0.0        0.0        0.0      400.0

ENTER 0 FOR NO CHANGE
      1 TO SPECIFY NEW TOTAL POWERS
      2 TO SPECIFY PERCENT CHANGES: 1

ENTER NEW TOTALS FOR
LOAD, GENERATION, SHUNT-MW, REACTOR-MVAR (NEG), CAPACITOR-MVAR:
1800                                                     New load
TOTAL GENERATOR LIMITS: PMAX =         0.0 PMIN =         0.0
ENTER 1 TO ENFORCE MACHINE POWER LIMITS: 0

TOTAL LOAD MVAR =     0.0. ENTER CHANGE CODE:
 0 FOR NO CHANGE          1 FOR CONSTANT P/Q RATIO
 2 FOR NEW TOTAL Q LOAD  3 FOR PERCENT CHANGE
 4 FOR NEW POWER FACTOR: 4                               Change power factor
ENTER POWER FACTOR:.95                                   Set power factor to 0.95

NEW: LOAD-MW LOAD-MVAR GENERATION   SHUNT-MW   REACTORS CAPACITORS
      1800.0     591.6        0.0        0.0        0.0      400.0   Confirmation
ENTER UP TO 20 AREA NUMBERS
0                                                        Exit SCAL, ready to go
```

Figure 7.2. Two Executions of Activity SCAL to Adjust Load and Generation

Figure 7.3, “Use of Activity SCAL to Investigate Effect of Changed Load Power Factor as Seen at High-Voltage Buses” and Figure 7.4, “Use of SCAL and CONL Together to Adjust Both Load Level and Assumption Regarding Voltage Characteristic (Sheet 1 of 2)” show examples of the use of activities SCAL and CONL. The base case system model is saved in case SCAC1 has a feasible solution when the power factor of the load taken from the high-voltage buses is unity. In the examples, the system’s sensitivity to increased reactive power load with reduced capacitor compensation in the distribution system is determined. Figure 7.3, “Use of Activity SCAL to Investigate Effect of Changed Load Power Factor as Seen at High-Voltage Buses” shows the use of activity SCAL to increase reactive power load by changing the power factor to 0.95. The attempt to solve the power flow with the greatly increased reactive load, which has a constant Mvar characteristic, fails. The system, which was already heavily loaded with unity load power factor, cannot support the additional reactive load. Figure 7.4, “Use of SCAL and CONL Together to Adjust Both Load Level and Assumption Regarding Voltage Characteristic (Sheet 1 of 2)” shows a variation on the conventional power flow analysis. Here SCAL is used to change the load power factor as before, but the standard power flow assumption that the load has a constant MVA characteristic is dropped. Instead, it is assumed that (1) voltages will fall so far that the majority of distribution system control devices will reach their limits without being able to restore customer buses to their rated voltages, and (2) that as a result, the load versus voltage characteristic will become equivalent to a mixture of a constant current and a constant admittance component. The new assumption is implemented by activity CONL immediately after activity SCAL, hence basing the transition from constant load MVA to voltage dependence on the voltage profile that existed in the base case. (The solved base case was restored to the working file just prior to the execution of SCAL.) The power flow solution succeeds in this case, but a review of voltages with VCHK indicates that voltages are very low and that the system could support very little additional load.

```
ACTIVITY? CASE SCAC1
SAMPLE SYSTEM FOR PSS®E MANUAL
1100KV DC CASE SCAC1.SAV WAS SAVED ON MON, NOV 06 1989 11:46

ACTIVITY? SCAL ALL
```

Use SCAL to change system reactive load level

```
BUS 1600 [MINE     765] MACHINE 1: PGEN= 1060.3 PMIN=   320.0 PMAX= 1010.0

BUS 1600 [MINE     765] MACHINE 2: PGEN= 1060.3 PMIN=   320.0 PMAX= 1010.0

BUS 1600 [MINE     765] MACHINE 3: PGEN= 1060.3 PMIN=   320.0 PMAX= 1010.0
```

These units are above their output limits

```
 LOAD-MW GENERATION   SHUNT-MW   REACTORS CAPACITORS
 6500.0      6930.8        0.0    -3100.0       300.0

ENTER 0 FOR NO CHANGE
      1 TO SPECIFY NEW TOTAL POWERS
      2 TO SPECIFY PERCENT CHANGES:

TOTAL LOAD MVAR =     0.0. ENTER CHANGE CODE:
 0 FOR NO CHANGE         1 FOR CONSTANT P/Q RATIO
 2 FOR NEW TOTAL Q LOAD 3 FOR PERCENT CHANGE
 4 FOR NEW POWER FACTOR: 4
ENTER POWER FACTOR:.95
```

Change power factor from unity to 0.95

```
NEW: LOAD-MW LOAD-MVAR GENERATION   SHUNT-MW   REACTORS CAPACITORS
      6500.0      2136.4      6930.8        0.0    -3100.0       300.0
```

Power factor change imposes substantial additional reactive power load

```
ACTIVITY? FNSL,OPT
```

Attempt power flow solution

```
TAP CODE IS 0 TO LOCK, 1 FOR STEPPING, 2 FOR DIRECT

ENTER:
 [TAP], [1 FOR AREA], [1 FOR PHSE], [1 TO FLT], [1 TO LOCK], [1 TO LOCK]
 [CODE]   [INTERCHNGE]   [SHIFTERS]   [START ]   [D.C. TAPS]   [SWCH SHNTS]
1

ENTER ITERATION NUMBER FOR VAR LIMITS
 0 FOR IMMEDIATELY, -1 TO IGNORE COMPLETELY:

ITER    DELTAP    BUS      DELTAQ    BUS      DELTA/V/    BUS    DELTAANG    BUS
  0     0.0001( 1200)     5.3411(  700)     0.09980(  500)    0.04539( 1100)
  1     1.0670(  100)     7.3899( 1100)     0.08955( 1100)    0.02300( 1100)
  2     0.2503(  100)     1.7974( 1100)     0.01709( 1100)    0.00484( 1100)
  3     0.0239(  100)     0.5308( 1100)     0.00481( 1100)    0.00135( 1100)
  4     0.0026(  100)     0.1493( 1100)     0.00134( 1100)    0.00041( 1100)
  5     0.0006(  100)    12.7514( 1100)     2.09861(  500)    2.84799(  500)
  6   279.1466(  500)   216.1235( 1201)     0.74833(  200)    0.78787( 1400)
  7    53.4620(  700)    29.3588( 1201)     1.81030( 1100)    0.99830(  200)
  8    13.1659(  100)    10.8905(  500)     3.69651( 1402)    2.29398( 1100)

BLOWN UP AFTER    9 ITERATIONS
```

Diverged inadequate reactive power supply

```
LARGEST MISMATCH:******** MW21747.93 MVAR 48027.01 MVA-BUS  1201 [SWIGA     230]
SYSTEM TOTAL ABSOLUTE MISMATCH:            110268.13 MVA
```

Figure 7.3. Use of Activity SCAL to Investigate Effect of Changed Load Power Factor as Seen at High-Voltage Buses

```
ACTIVITY? CASE SCAC1
SAMPLE SYSTEM FOR PSS®E MANUAL
1100KV DC CASE
```

Return to base case to try alternative analysis of reactive load issue

```
CASE SCAC1.SAV WAS SAVED ON MON, NOV 06 1989  11:46

ACTIVITY? SCAL ALL
```

Use SCAL again for same reactive load change

```
BUS  1600 [MINE     765] MACHINE 1: PGEN=  1060.3  PMIN=   320.0  PMAX=  1010.0

BUS  1600 [MINE     765] MACHINE 2: PGEN=  1060.3  PMIN=   320.0  PMAX=  1010.0

BUS  1600 [MINE     765] MACHINE 3: PGEN=  1060.3  PMIN=   320.0  PMAX=  1010.0

 LOAD-MW GENERATION   SHUNT-MW   REACTORS CAPACITORS
  6500.0     6930.8        0.0    -3100.0      300.0

ENTER 0 FOR NO CHANGE
      1 TO SPECIFY NEW TOTAL POWERS
      2 TO SPECIFY PERCENT CHANGES:

TOTAL LOAD MVAR =    0.0. ENTER CHANGE CODE:
 0 FOR NO CHANGE          1 FOR CONSTANT P/Q RATIO
 2 FOR NEW TOTAL Q LOAD   3 FOR PERCENT CHANGE
 4 FOR NEW POWER FACTOR: 4
ENTER POWER FACTOR: .95

NEW: LOAD-MW  LOAD-MVAR GENERATION   SHUNT-MW   REACTORS CAPACITORS
      6500.0     2136.4     6930.8        0.0    -3100.0      300.0
```

Same reactive load change as before

```
ACTIVITY? CONL ALL
ENTER % CONSTANT I, % CONSTANT G FOR REAL POWER: 50 50
ENTER % CONSTANT I, % CONSTANT B FOR REACTIVE POWER: 25 75
```

Use CONL to change assumption regarding load-voltage characteristic

Change real power to
50% const I
50% const G

Reactive characteristic differs from that for real power

```
LOAD TO BE REPRESENTED AS:
   REAL   REACTIVE
  0.00%     0.00% CONSTANT POWER
 50.00%    25.00% CONSTANT CURRENT
 50.00%    75.00% CONSTANT ADMITTANCE
ENTER 1 IF O.K., 0 OTHERWISE: 1
```

That's what I want

```
LOADS CONVERTED AT      6 OF      6 LOAD BUSES

ACTIVITY? FNSL,OPT
```

Attempt a power flow solution

```
TAP CODE IS 0 TO LOCK, 1 FOR STEPPING, 2 FOR DIRECT

ENTER:
 [TAP ] , [1 FOR AREA] , [1 FOR PHSE] , [1 TO FLT] , [1 TO LOCK] , [1 TO LOCK ]
 [CODE]   [INTERCHNGE]   [SHIFTERS  ]   [START   ]   [D.C. TAPS]   [SWCH SHNTS]
1

ENTER ITERATION NUMBER FOR VAR LIMITS
 0 FOR IMMEDIATELY, -1 TO IGNORE COMPLETELY: 0

ITER    DELTAP    BUS      DELTAQ    BUS      DELTA/V/    BUS    DELTAANG    BUS
  0     0.0001( 1200)     5.3411(  700)     0.19703( 1300)     0.12104( 1100)
  1     5.6879(  100)     1.1620(  100)     0.14087(  300)     0.23773(  800)
  2     1.5653(  700)     0.1482( 1550)     0.12382(  500)     0.12146(  700)
  3     3.4174(  100)     0.1703(  200)     0.10573(  500)     0.10418(  700)
  4     0.9304(  700)     0.1283(  700)     0.09222(  500)     0.08282(  700)
  5     2.5339(  100)     0.1326(  200)     0.04061( 1300)     0.09759(  500)
  6     1.0470(  100)     0.0625( 1550)     0.02052( 1300)     0.04396(  500)
  7     0.5326(  100)     0.0192(  700)     0.00862( 1300)     0.02091(  500)
  8     0.2147(  100)     0.0091(  700)     0.00388( 1300)     0.00885(  500)
  9     0.0974(  100)     0.0038(  700)     0.00168( 1300)     0.00393(  500)
 10     0.0420(  100)     0.0017(  700)     0.00074( 1300)     0.00170(  500)
 11     0.0184(  100)     0.0007(  700)     0.00032( 1300)     0.00074(  500)
 12     0.0079(  100)     0.0004( 1403)     0.00013( 1300)     0.00032(  500)
 13     0.0032(  100)     0.0002( 1201)     0.00005( 1300)     0.00013(  500)
 14     0.0013(  100)     0.0001( 1200)     0.00002( 1300)     0.00006(  500)
 15     0.0006(  100)     0.0001( 1403)

REACHED TOLERANCE IN  15 ITERATIONS
```

Took a lot of iterations and tap changes, but we got a solution

Figure 7.4. Use of SCAL and CONL Together to Adjust Both Load Level and Assumption Regarding Voltage Characteristic (Sheet 1 of 2)

```
LARGEST MISMATCH:    -0.06 MW    0.00 MVAR     0.06 MVA-BUS   100 [NUCLEAR  345]
SYSTEM TOTAL ABSOLUTE MISMATCH:                0.17 MVA


ACTIVITY? VCHK
```

VCHK to see how the voltages look

```
ENTER VMAX, VMIN:
     PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS®E      MON, NOV 06 1989  11:55
SAMPLE SYSTEM FOR PSS®E MANUAL
1100KV DC CASE

BUSES WITH VOLTAGE GREATER THAN 1.0500:

X------ BUS -----X AREA V(PU)  V(KV)    X------ BUS -----X AREA V(PU)  V(KV)

                                  * NONE *


BUSES WITH VOLTAGE LESS THAN 0.9500:

X------ BUS -----X AREA V(PU)  V(KV)    X------ BUS -----X AREA V(PU)  V(KV)
  300 WEST      345    1 0.7404 255.45    400 EAST      345    1 0.7507 258.99
  500 WESTLV    230    2 0.7766 178.62    600 EASTLV    230    2 0.8019 184.43
  700 SWURB     230    2 0.7790 179.18    800 SETOUN    230    2 0.8249 189.73
 1100 CATNIP    230    2 0.9169 210.88   1200 STERML    230    3 0.9018 207.41
 1201 SWIGA     230    3 0.8928 205.35   1300 SERGA     230    3 0.7798 179.36
 1400                  1 0.9095          1401 WCOND    18.0    3 0.9132 16.437
 1402 ECOND    18.0    3 0.9132 16.437   1403 WDUM     18.0    3 0.8979 16.161
 1404 EDUM 18.0    3 0.8979 16.161
```

They don't look too hot! This system is loaded heavily, even when load power factor is compensated to unity

Figure 7.5. Use of SCAL and CONL Together to Adjust Both Load Level and Assumption Regarding Voltage Characteristic (Sheet 2 of 2)

7.5. Feasibility Studies and Interchange Transaction Analysis

7.5.1. The Linearized Power Flow Model

Chapters 5 and 6 discuss the theory of power flow solution and the standard PSS®E iterative schemes for primary power flow solutions, respectively. During the early stages of the planning process, when identifying feasible, alternative expansion plans, it may be acceptable to use approximate, computationally more efficient, power flow models. For example, in the daily operation of a power system, the user may be presented, from an online system, a model of the expected load, generation, and transmission system for the day. For this system condition, the user may want to run a quick analysis of transfer limits for the base case and several contingencies. Because the results may go back to the online system, a computationally more efficient model is needed. One very widely used approximation is the linearized or dc power flow, which converts the nonlinear ac problem into a simple, linear circuit analysis problem. The advantage of this approach is that efficient, noniterative numerical techniques can be used to compute an approximate power flow solution. Many alternatives or contingencies can be investigated with the same computer effort that would be expended to calculate one ac power flow solution.

The dc power flow model is useful for rapid calculation of real power flow. It ignores reactive power flow and changes in voltage magnitudes, and assumes that, for most circuits, $X_{ij} >> R_{ij}$ and the angle between two buses is small. These assumptions result in the power flow from bus *i* to bus *k* simplifying to

$$P_{ij} = \frac{\theta_i - \theta_j}{X_{ij}} \tag{7.1}$$

where

θ_i

Angle at bus *i*.

θ_j

Angle at bus *j*.

X_{ij}

Reactance between bus *i* and bus *j*.

The power injected into a single bus is just the sum of the power on all circuits into the bus or

$$P_i = \sum_{ij}^{n} P_{ij} = \sum_{ij}^{n} \frac{\theta_i - \theta_j}{X_{ij}} \tag{7.2}$$

shown in matrix form as

[P] = [B] [θ] for a system of N buses (7.3)

Note that Equation 7.3 is a linear equation and that the admittance matrix [*B*] is sparse because there are only several transmission lines connected to each bus. The solution of this system of equations can be accomplished efficiently by the numerical technique of triangular factorization. The power injections, [P], are known, and the phase angles, [θ], are computed. After the phase-angle solution has been determined, the real power flows can be computed using Equation 7.1. Figure 7.6, "FNSL versus DCLF Results Comparison" illustrates the results of two power flow solutions run on the same 20-bus system. The real power flows, as calculated by the dc solution, are shown in parentheses. The calculated power flows are very similar. For this example, the dc power flow model would be adequate to determine whether MW flows in the transmission circuits are within rated values.

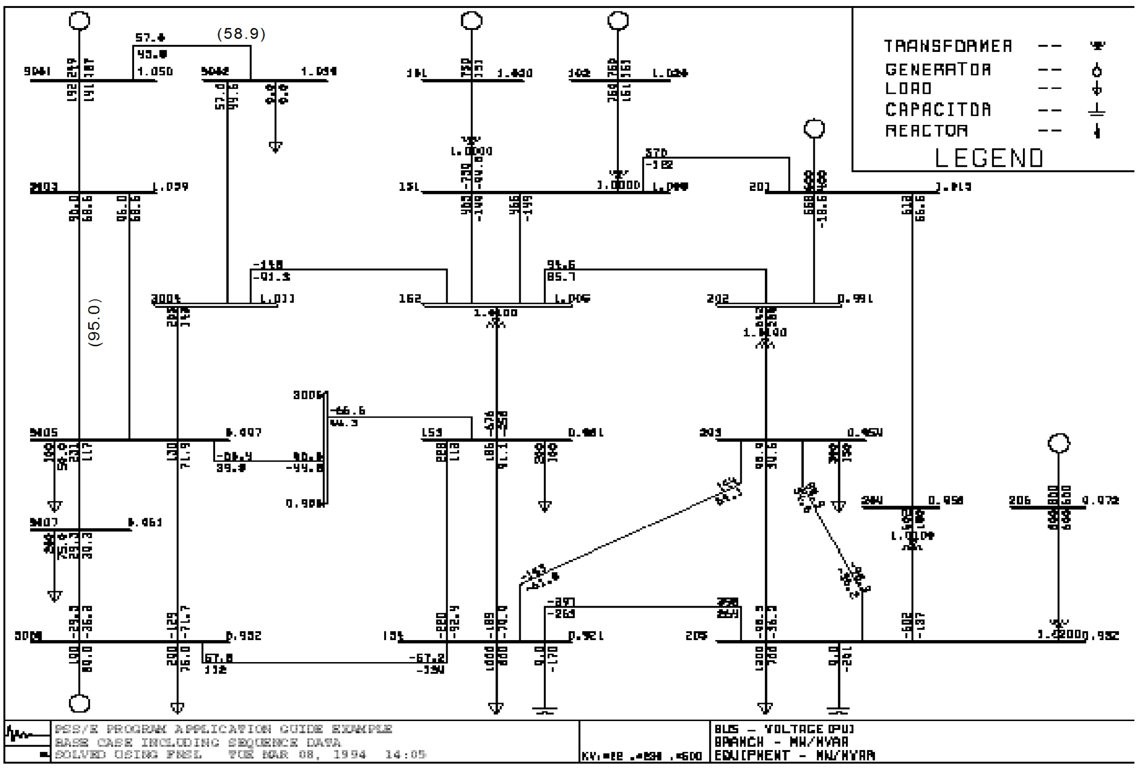


Figure 7.6. FNSL versus DCLF Results Comparison

7.5.2. Sensitivity Techniques

In the day-to-day operation of interconnected networks, bulk power transfer is often constrained by the ability of transmission elements to withstand thermal effects for various normal and contingency conditions. More recently this bulk power transfer is often constrained by stability limits. If sufficient stability analysis has been run, megawatt limits can be assigned to elements or groups of elements. Because the transfers of power amount to thousands of megawatts for many hours in every single day, the determination of the ability of the transmission system to support the power transfers is a vital consideration to assure that the interconnected network is operated in a secure and reliable manner.

In Section 7.5.1, "The Linearized Power Flow Model "a dc technique gives a quick solution. A common approach used to find a limiting solution is to start with a base case and calculate the sensitivity of flow in monitored elements or groups of elements to a variation in interchange. This technique is often referred to as a distribution factor technique. When the sensitivity of elements is known, linear projection estimates permissible interchange. Figure 7.7, "Linear Projection Technique Used in Transfer Limit Analysis" graphically shows this technique.

In Figure 7.8, "Line Outage Comparison of DCLF and FNSL" the flows are shown for the ac and the dc solution for a line-out contingency. Again, the real power flows are very close. In Table 7.1, "Megawatt Changes ", the change in MW calculated on the earlier base cases of Figure 7.6, "FNSL versus DCLF Results Comparison" are shown. The distribution factor technique would be very well suited to the system to calculate transfer limits.

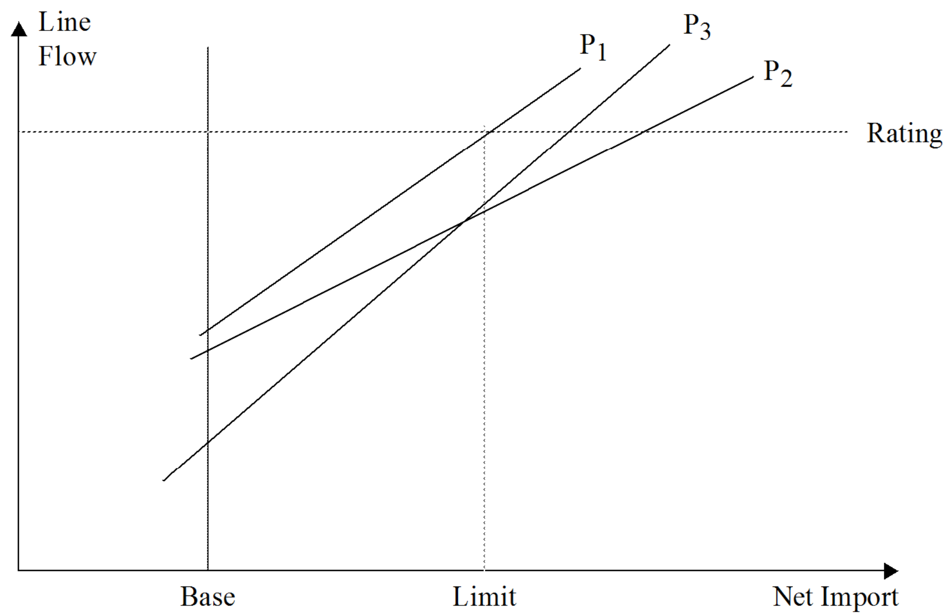


Figure 7.7. Linear Projection Technique Used in Transfer Limit Analysis

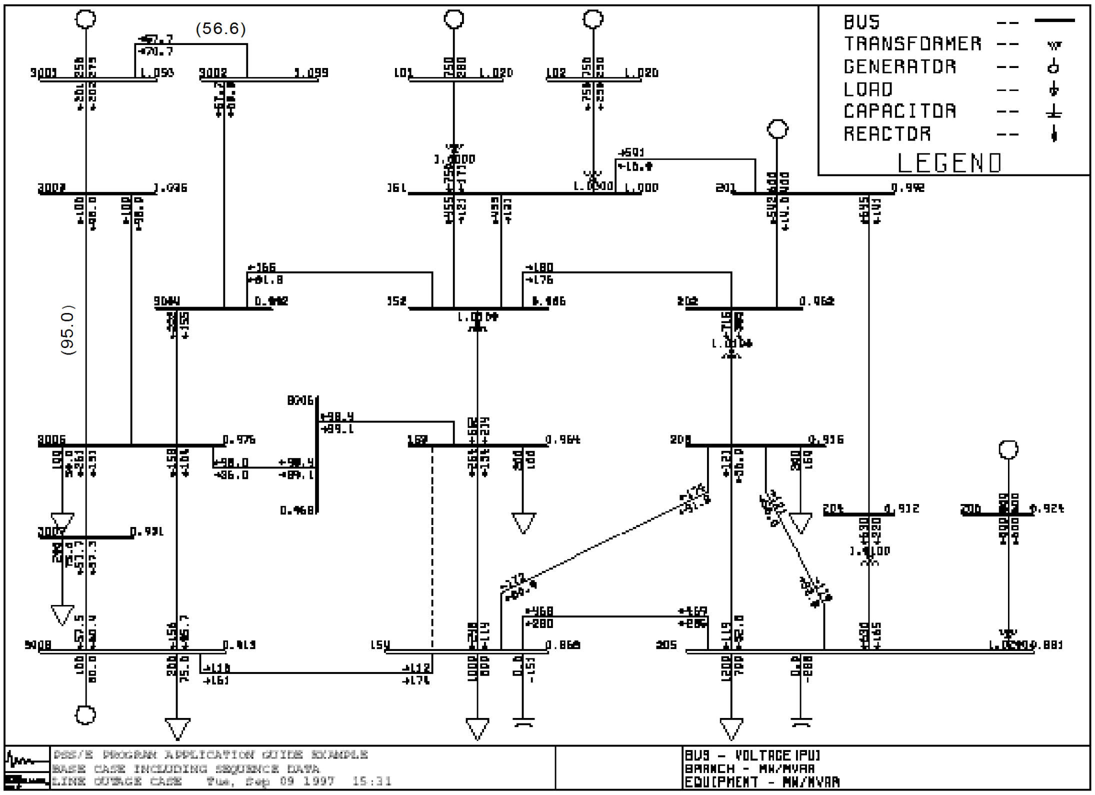


Figure 7.8. Line Outage Comparison of DCLF and FNSL

Table 7.1. Megawatt Changes

Branch	ac	dc
151-152	–10	–13
153-152	124	128
153-154 CKT2	68	64
3004-152	17	17
203-154	30	31

7.5.3. Implementation of Linearized Power Flow Model and Sensitivity Techniques

In implementing a linearized power flow solution, some flexibility exists on what assumptions are made. Those activities that apply a dc power flow technique in the standard package and in the enhancement section of PSS®E all use the same assumptions. They are discussed in this section.

Standard dc network analogy techniques, described in textbooks and various IEEE papers, assume unity voltage at each bus in the network. PSS®E does its solutions with voltages contained in the working files. This assumption impacts the solution in two ways: First, all real shunts are converted to a constant load at this initial voltage, and second, line losses are estimated on this initial voltage vector. These losses are assumed constant and are injected as loads during all solutions including change cases at the sending-end of the branch. In reports, the user will see different flows at the ends of the line. Also, in all activities using the dc solution technique, percent rating is calculated based only on MW flow, in contrast to the ac solutions where ratings are based on MVA flow.

7.5.4. Activity DCLF

Activity DCLF, provided to all PSS®E installations, is the most fundamental function in PSS®E using the linearized solution technique. DCLF is used in the following situations:

1. A quick solution is desired, and voltage is not a problem.
2. A line outage case is to be compared with a case on the same output sheet.
3. An angle estimate other than 0 degrees is desired in setting up a new case. (Rarely has providing an angle estimate at buses allowed a solution to be easily reached where starting with no estimate has failed.)

Dialog and resulting output are shown in Figure 7.9, "Typical DCLF Dialog" and Figure 7.10, "Typical DCLF Output Showing Outage to Circuit 2 Branch from Bus 153 to Bus 154" for a typical case.

```
 ACTIVITY? case savnw                                          Do Linearized solution and
 PSS®E PROGRAM APPLICATION GUIDE EXAMPLE                       get output for an area
 BASE CASE INCLUDING SEQUENCE DATA

 CASE savnw.sav WAS SAVED ON TUE NOV 06, 1990  09:59

 ACTIVITY? dclf area

 ENTER OUTPUT DEVICE CODE:
  0 FOR NO OUTPUT        1 FOR CRT TERMINAL
  2 FOR A FILE           3 FOR QMS PS2000
  4 FOR QMS_PS800        5 FOR HARD COPY TERMINAL
  6 FOR ALTERNATE SPOOL DEVICE: 1

 WORKING CASE HAS LARGEST MISMATCH OF      0.00 MW AT BUS   205 [SUB230   230]

 ENTER 1 FOR RATEA, 2 FOR RATEB, 3 FOR RATEC (DEFAULT=1): 1               Use rate A

 FOR CHANGE CASE SOLUTION
 ENTER FROM BUS, TO BUS, CIRCUIT IDENTIFIER
  (FROM BUS = 0 FOR NO CHANGE CASE): 153 154 1                           Take circuit 1 from
                                                                         bus 153 to bus 154 out
 CIRCUIT 1  FROM   153 [MID230   230] TO   154 [DOWNTN   230] IS NOW IN
 CHANGE ITS STATUS? 1

 NEW STATUS OF CKT 1  FROM   153 [MID230   230] TO   154 [DOWNTN   230] IS OUT
 ENTER UP TO 20 AREA NUMBERS
1                                                      Area 1
 ENTER UP TO 20 AREA NUMBERS
0

 WHICH VOLTAGES SHOULD BE SAVED?
   0 = ORIGINAL VOLTAGES
   1 = BASE CASE DC LOAD FLOW VOLTAGES
   2 = CHANGE CASE DC LOAD FLOW VOLTAGES: 0                Leave original network and solution
                                                           in working files
 ORIGINAL VOLTAGES RETAINED

 CIRCUIT 1  FROM   153 [MID230   230] TO   154 [DOWNTN   230]
 FOR CHANGE CASE SOLUTION STATUS WAS SET TO OUT
 ENTER 1 TO SAVE NEW STATUS: 0
```

Figure 7.9. Typical DCLF Dialog

```
                    PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS®E      THU SEP 27, 1990  10:50
                           PSS®E PROGRAM APPLICATION GUIDE EXAMPLE
                           BASE CASE INCLUDING SEQUENCE DATA
                  CHANGE CASE: CIRCUIT 2  FROM   153 [MID230    230] TO   154 [DOWNTN   230] IS OUT
                                      OUTPUT FOR AREA   1 [FLAPCO]

<======================== BUS DATA =======================> <============================ LINE DATA ============================>
 FROM                        BASE  CHANGE   GEN.    LOAD           TO                       BASE CASE  RATE CHANGE CASE   DELTA
 BUS      NAME    AREA ZONE ANGLE  ANGLE     MW      MW            BUS     NAME      CKT AREA  MW     %   MVA    MW    %    MW
===== ============ ==== ==== =====  =====  ======  ======        ===== ============ === ==== ====== === ==== ====== === ======

  101 NUC-A    21.6   1    1  16.1   16.1   750.0     0.0 ---------------------------------------------------------------------
                                                                151 NUCPANT  500  1    1  750.0  60 1250  750.0  60    0.0
  102 NUC-B    21.6   1    1  16.1   16.1   750.0     0.0 ---------------------------------------------------------------------
                                                                151 NUCPANT  500  1    1  750.0  60 1250  750.0  60    0.0
  151 NUCPANT   500   1    1  11.8   11.8     0.0     0.0 ---------------------------------------------------------------------
                                                                101 NUC-A   21.6  1    1 -750.0  60 1250 -750.0  60    0.0
                                                                102 NUC-B   21.6  1    1 -750.0  60 1250 -750.0  60    0.0
                                                                152 MID500   500  1    1  463.4  39 1200  452.4  38  -11.0
                                                                152 MID500   500  2    1  463.4  39 1200  452.4  38  -11.0
                                                                201 HYDRO    500  1    2  573.2  48 1200  595.1  50   21.9
  152 MID500    500   1    1  -0.3    0.0     0.0     0.0 ---------------------------------------------------------------------
                                                                151 NUCPANT  500  1    1 -457.8  38 1200 -446.9  37   11.0
                                                                151 NUCPANT  500  2    1 -457.8  38 1200 -446.9  37   11.0
                                                                153 MID230   230  1    1  674.2  27 2500  573.2  23 -101.0
                                                                202 EAST500  500  1    2  103.0   9 1200  168.3  14   65.3
                                                               3004 WEST     500  1    5  138.5             152.3       13.7
  153 MID230    230   1    1  -2.2   -1.6     0.0   200.0 ---------------------------------------------------------------------
                                                                152 MID500   500  1    1 -674.2  27 2500 -573.2  23  101.0
                                                                154 DOWNTN   230  1    1  223.1 112  200  283.3 142   60.2
                                                          --->  154 DOWNTN   230  2    1  185.9  93  200   XXXX     -185.9
                                                               3006 UPTOWN   230  1    5   65.2              89.9       24.7
  154 DOWNTN    230   1    1  -7.9   -8.8     0.0  1000.0 ---------------------------------------------------------------------
                                                                153 MID230   230  1    1 -219.8 110  200 -280.0 140  -60.2
                                                          --->  153 MID230   230  2    1 -183.1  92  200   XXXX      183.1
                                                                203 EAST230  230  1    2 -144.8  72  200 -169.0  85  -24.3
                                                                205 SUB230   230  1    2 -406.7  68  600 -469.7  78  -63.0
                                                               3008 CATDOG   230  1    5  -45.6  11  400  -81.3  20  -35.6
```

Figure 7.10. Typical DCLF Output Showing Outage to Circuit 2 Branch from Bus 153 to Bus 154

7.5.5. Activity DFAX/OTDF

Often in planning day-to-day operations of an interconnected system it is advantageous to very quickly evaluate the impact on key elements of large power injections at different locations. These injections can be either positive or negative and are typically caused by system disturbances such as loss of a line, trip of a generator, or loss of load. One of the easiest ways to do this is to have a table of distribution factors that gives the sensitivity of disturbances. Activity OTDF prints these factors for a variety of single contingencies.

Monitored elements, contingencies and any subsystem definition required by any of the linearized power flow activities and the AC Contingency Analysis must be first read in by activity DFAX (see PSS®E Program Operation Manual, Section 6.10, Performing AC Contingency Analysis).

Figure 7.11, "System Definition" shows a system where the key system (circled) is bounded on the EAST and WEST. All tie-lines are considered key elements and are monitored. The tie-lines as a group from the EAST and WEST are also considered keys to reliable power and are monitored as interfaces. Figure 7.12, "Monitored Element File" lists the monitored element file that would be entered, based on these key lines and interfaces. A series of probable contingencies are listed in Figure 7.13, "Contingency Description Data File".

Figure 7.14, "Dialog Using Activity OTDF" shows the terminal dialog produced while running activities DFAX and OTDF. Note OTDF only allows single contingencies where a power shift can be defined and any multiple contingencies in the contingency file will be flagged. From the resulting output, shown in Figure 7.15, "OTDF Contingency List and Distribution Factors", the user is able to quickly calculate impacts on the lines and interfaces.

For example, for contingency SINGLE2, which is an open line from bus 152 to bus 202, with monitored element 3008 [CATDOG 230] to 154 [DOWTN 230], a distribution factor of 0.17116 is shown. This means for the loss of *X* MW, due to loss of this line, the resultant flow on this monitored element could be estimated by

$P_{\text{initial flow}} + X \times 0.17116$

where $P_{\text{initial flow}}$ in the initial ac case is 57.8 MW.

The distribution factors are based on a dc solution. If no units are specified in the contingency file to participate in redispatch, then the swing bus picks up the power. The resultant distribution factors should be used with care. All flow directions and distribution factor polarities on monitored branches and ties are always based on the way they are specified. The amount of power shift on an outaged element is based on the sending end flow; in other words, the greater flow regardless of which bus is specified first. This consistency or convention was established so that the same distribution factors are printed regardless of which way the outage was specified.

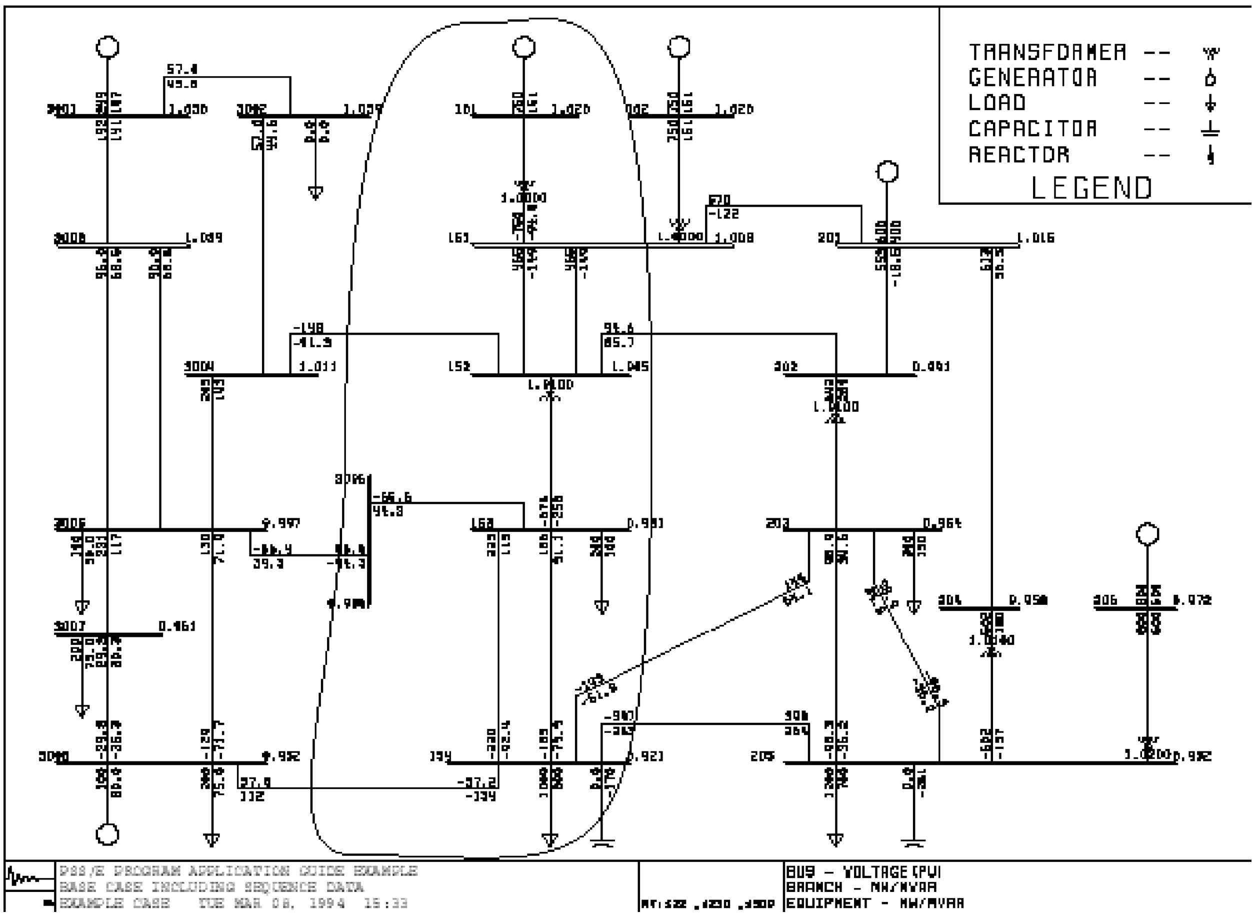


Figure 7.11. System Definition

```
MONITOR BRANCHES
3004 152
3006 153
3008 154
 201 151
 202 152
 203 154
 205 154
END
MONITOR INTERFACE WEST RATING 200 MW
3004 152
3006 153
3008 154
END
MONITOR INTERFACE EAST RATING 350 MW
MONITOR TIES FROM AREA 1 TO AREA 2
END
END
```

Interfaces can be entered as individual branches or by a group; interface EAST is all tie lines from Area 1 to Area 2

Figure 7.12. Monitored Element File

```
CONTINGENCY TRIP1NUCLEAR
REMOVE UNIT 1 FROM BUS 101
END
CONTINGENCY TRIP2NUCLEAR
REMOVE UNIT 1 FROM BUS 101
REMOVE UNIT 1 FROM BUS 102
END
CONTINGENCY ADDLARGELOAD
INCREASE BUS 154 LOAD BY 50 PERCENT
END
SINGLE TIE FROM AREA 1 TO AREA 2
DOUBLE TIE FROM AREA 1 TO AREA 5
END
```

Multiple contingencies

Various options to run automatic contingencies

Figure 7.13. Contingency Description Data File

```
ACTIVITY? case savnw
PSS®E PROGRAM APPLICATION GUIDE EXAMPLE
BASE CASE INCLUDING SEQUENCE DATA

CASE savnw.sav WAS SAVED ON WED APR 15, 1992  15:14

ACTIVITY? fnsl
```

Should be solved case

```
ENTER ITERATION NUMBER FOR VAR LIMITS
 0 FOR IMMEDIATELY, -1 TO IGNORE COMPLETELY: 0

ITER    DELTAP    BUS      DELTAQ    BUS      DELTA/V/    BUS    DELTAANG    BUS
  0     0.0000(  151)      0.0001(  205)
                                               0.00001(  205)    0.00000(  101)

  1     0.0000(  151)      0.0001(  205)


REACHED TOLERANCE IN   1 ITERATIONS

LARGEST MISMATCH:    0.00 MW    0.01 MVAR     0.01 MVA-BUS   205 [SUB230   230]
SYSTEM TOTAL ABSOLUTE MISMATCH:               0.04 MVA

ACTIVITY? dfax

ENTER FILENAME FOR STORING DISTRIBUTION FACTORS
RETURN TO EXIT: savnw.dfax

FOR THE SUB-SYSTEM DESCRIPTION FILE,
ENTER INPUT FILE NAME (RETURN FOR NONE, 1 FROM TERMINAL): savnw.sub

PROCESSING THE SUB-SYSTEM DESCRIPTION FILE...

FOR THE MONITORED ELEMENT DESCRIPTION FILE,
ENTER INPUT FILE NAME (RETURN TO EXIT, 1 FROM TERMINAL): savnw.mon

PROCESSING THE MONITORED ELEMENT DESCRIPTION FILE...

ENTER 1 TO SORT MONITORED BRANCH LIST
      0 TO LEAVE IN MONITORED ELEMENT FILE ORDER: 0

FOR THE CONTINGENCY DESCRIPTION FILE,
ENTER INPUT FILE NAME (RETURN TO EXIT, 1 FROM TERMINAL): savnw.con
```

Enter subsystem definitions, monitored elements and contingency description

```
PROCESSING THE CONTINGENCY DESCRIPTION FILE...

ACTIVITY? otdf
```

Print outage distribution factors

```
WORKING CASE HAS LARGEST MISMATCH OF      0.00 MW AT BUS   151 [NUCPANT   500]

ENTER OUTPUT DEVICE CODE:
 0 FOR NO OUTPUT     1 FOR CRT TERMINAL
 2 FOR A FILE        3 FOR QMS PS2000
 4 FOR QMS_PS800     5 FOR HARD COPY TERMINAL
 6 FOR ALTERNATE SPOOL DEVICE: 2
ENTER OUTPUT FILE NAME: fig7.29a
ENTER DISTRIBUTION FACTOR FILENAME: savnw.dfax
```

Created by activity DFAX

```
MULTIPLE EVENT CONTINGENCY 'TRIP2NUCLEAR' INVALID IN OTDF

MULTIPLE EVENT CONTINGENCY 'DOUBLE 1' INVALID IN OTDF

MULTIPLE EVENT CONTINGENCY 'DOUBLE 2' INVALID IN OTDF

MULTIPLE EVENT CONTINGENCY 'DOUBLE 3' INVALID IN OTDF

ACTIVITY?
```

Only single contingencies allowed

Figure 7.14. Dialog Using Activity OTDF

```
 ..............................................................................................
.............
 .                        PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS®E   WED APR 15, 1992  15:17         .
 .                                                                                                       .
 .                             PSS®E PROGRAM APPLICATION GUIDE EXAMPLE                                   .
 .                             BASE CASE INCLUDING SEQUENCE DATA                                         .
 .                                                                                                       .
 .                                         *** OTDF CONTINGENCY SUMMARY ***                              .
 ......................

 SUBSYSTEM DESCRIPTION FILE:   savnw.sub
 MONITORED ELEMENT FILE:       savnw.mon
 CONTINGENCY DESCRIPTION FILE: savnw.con

 <-CONTINGENCY-> <-MW SHIFT-> <---------------------------------------CONTINGENCY DESCRIPTION---------------------------
----------->

   TRIP1NUCLEAR      750.0     REMOVE UNIT 1 FROM BUS 101 [NUC-A   21.6]

   ADDLARGELOAD      500.0     INCREASE BUS 154 [DOWNTN    230] LOAD BY 50 PERCENT

   SINGLE 1          570.0     OPEN LINE FROM BUS 151 [NUCPANT  500] TO BUS 201 [HYDRO    500] CKT 1

   SINGLE 2           94.4     OPEN LINE FROM BUS 152 [MID500   500] TO BUS 202 [EAST500  500] CKT 1

   SINGLE 3         -142.6     OPEN LINE FROM BUS 154 [DOWNTN   230] TO BUS 203 [EAST230  230] CKT 1

   SINGLE 4         -397.2     OPEN LINE FROM BUS 154 [DOWNTN   230] TO BUS 205 [SUB230   230] CKT 1

..............................................................................................
............
 .                       PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS®E   THU SEP 27, 1990  11:14         .
 .                                                                                                       .
 .                             PSS®E PROGRAM APPLICATION GUIDE EXAMPLE                                   .
 .                             BASE CASE INCLUDING SEQUENCE DATA                                         .
 .                                                                                                       .
 .                                      *** OTDF DISTRIBUTION FACTOR TABLE ***                           .

..............................................................................................
............

                CONTINGENCY LABEL--> BASE CASE MW TRIP1NUCLEAR ADDLARGELOAD  SINGLE 1    SINGLE 2    SINGLE 3    SINGLE 4
                  POWER SHIFT (MW)-->    AC      DC       750.0        500.0     570.0        94.6       143.7       398.1
 <----- FROM -----> <------ TO ------>CKT <----> <---->><----------> <----------> <----------> <----------> <---------->
<---------->
  3004 WEST     500   152 MID500   500 1  -148.0 -137.8   0.42970      0.34650    -0.06717    -0.11838    -0.06753    -0.11150
  3006 UPTOWN   230   153 MID230   230 1   -66.6  -65.1   0.29908      0.26124    -0.03113    -0.05405    -0.03150    -0.05093
  3008 CATDOG   230   154 DOWNTN   230 1    57.8   46.2   0.27121      0.39226     0.09266     0.17036     0.09139     0.16028
   201 HYDRO    500   151 NUCPANT  500 1  -566.7 -570.0   0.41830     -0.07627     0.99436    -0.40888     0.00365     0.19164
   202 EAST500  500   152 MID500   500 1   -94.4 -102.7  -0.13953     -0.22736    -0.67101     0.99794     0.32428     0.36485
```

Figure 7.15. OTDF Contingency List and Distribution Factors

7.5.6. Contingency Activities

Activity DCCC

Activity DCCC is provided to allow the user to process several different types of contingencies rapidly and see the loading impact they cause on lines and interfaces. It uses the same distribution factor file created by activity DFAX for OTDF. Activity DCCC does recognize multiple contingencies. As with all the dc analogy methods, the user must recognize the approximate nature of the solution. Like OTDF for generation or load changes, the swing bus is assumed to pick up the change in power unless the user specifies units to participate in redispatch in the subsystem description file. DCCC allows two different reports:

1. A list of the monitored lines and interfaces that are overloaded.

2. A tabular report of the percent loadings on all monitored branches and interfaces, flagging those that are overloaded.

DCCC allows the user to choose whether contingencies should be based on the initial ac or dc solution. An outaged branch may show a flow if the ac solution is chosen. This discrepancy is the difference between the ac and dc base solutions.

AC Contingency Calculation

The AC Contingency Analysis solves contingent systems using an ac power flow solution. It requires the user to first run activity DFAX in order to read the subsystem data file, contingency description data file, and the monitored element description file (see PSS®E Program Operation Manual, Performing AC Contingency Analysis).

The activity reports on monitored element and bus voltage loading. This activity is structured to run more quickly than if the user tried to manually run cases through IDEV files or IPLAN.

7.5.7. Activity TLTG

Activity TLTG does the same sensitivity type analysis as described in Section 7.5.2, "Sensitivity Techniques ". This activity will run all the contingencies as entered in the contingency description file processed by activity DFAX.

Activity TLTG also uses the monitored list file, which allows the lines to be monitored and interfaced. This feature is important because these interfaces often define stability limits. The systems controlling the interchanges can be either entered interactively or via the subsystem description data file.

For the system shown in Figure 7.11, "System Definition", the subsystem description file (Figure 7.16, "Subsystem Description File") has been created. Figure 7.17, "TLTG Interactive Dialog (Sheet 1 of 2)" shows the interactive dialog when running TLTG. The user's choice of systems to control interchange is interactive. This activity allows the choice of a summary report or complete loading report of all monitored elements. TLTG also includes dialog to further restrict the output; i.e., just showing *n* most restrictive elements in the loading tables.

```
SYSTEM STUDY
AREA 1
END
SYSTEM WEST
BUSES 3001 3008
END  <------------------------------  Buses 3001 through 3008 inclusive
SUBSYSTEM EAST
AREA 2
END
END
```

Figure 7.16. Subsystem Description File

In the example run, the user thought the files were specified in the monitored description file and chose not to have them included automatically in the monitored description list. However, activity TLTG is sensitive to the direction of monitored branches specified in the monitored description file. Because activity TLTG automatically specifies the monitored ties as coming out of the study system, the user did not have them specified. The reporting would have had duplicate branches monitored from opposite directions if the files had been requested by the user. Branches specified in the same direction (based on convention) are flagged as previously entered by the activity.

In activity TLTG redispatch is done according to MBASE. Optionally, for the transfer, the user can specify units to participate in the subsystem description file.

```
ACTIVITY? tltg

SOLUTION PARAMETERS ARE:
 1:    0.5  MW MISMATCH TOLERANCE
 2:      1  BASE CASE RATING (1=RATEA, 2=RATEB, 3=RATEC)
 3:      1  CONTINGENCY CASE RATING (1=RATEA, 2=RATEB, 3=RATEC)
 4:  100.0  PERCENT OF RATING
 5:      0  LINE FLOW CODE (0=DC BASE CASE, 1=AC BASE CASE)
 6:      0  PHASE SHIFTER CODE (0=LOCKED, 1=REGULATING IN BASE CASES)
 7:      0  (0=IGNORE BASE CASE CONSTRAINTS IN CONTINGENCY CASES, 1=INCLUDE)
 8:      0  LIST STUDY SYSTEM BUSES (0=NO, 1=YES)
 9:      0  LIST OPPOSING SYSTEM BUSES (0=NO, 1=YES)
10:      0  LIST STUDY SYSTEM TIE LINES (0=NO, 1=YES)
11:      0  ADD STUDY SYSTEM TIES TO MONITORED LINE LIST (0=NO, 1=YES)
12:      0  OUTPUT CODE (0=SUMMARY, 1=FULL)
13:      0  INTERCHANGE LIMIT OUTPUT CODE (0=INCREMENTAL, 1=TOTAL)
14:  24000  NUMBER OF ELEMENTS TO INCLUDE IN FLOW TABLES
15:  9999.  SUMMARY TABLE MAXIMUM IMPORT OR EXPORT (>0.)
16: 0.0000  SUMMARY TABLE MINIMUM DISTRIBUTION FACTOR MAGNITUDE
17:      5  SUMMARY TABLE MAXIMUM TIMES FOR REPORTING THE SAME ELEMENT
18:      0  APPLY SUMMARY MIN. DISTR. FACTOR TO SOLUTION REPORTS (0=NO, 1=YES)
19:    0.0  MINIMUM CONTINGENCY CASE PRE-SHIFT FLOW CHANGE
20: 0.0000  MINIMUM CONTINGENCY CASE DISTRIBUTION FACTOR CHANGE
21:      0  CONVERT RATINGS TO ESTIMATED MW RATINGS (0=NO, 1=YES)
ENTER PARAMETER CODE, NEW VALUE: 4,90
```

Specify percent rating

```
SOLUTION PARAMETERS ARE:
 1:    0.5  MW MISMATCH TOLERANCE
 2:      1  BASE CASE RATING (1=RATEA, 2=RATEB, 3=RATEC)
 3:      1  CONTINGENCY CASE RATING (1=RATEA, 2=RATEB, 3=RATEC)
 4:   90.0  PERCENT OF RATING
 5:      0  LINE FLOW CODE (0=DC BASE CASE, 1=AC BASE CASE)
 6:      0  PHASE SHIFTER CODE (0=LOCKED, 1=REGULATING IN BASE CASES)
 7:      0  (0=IGNORE BASE CASE CONSTRAINTS IN CONTINGENCY CASES, 1=INCLUDE)
 8:      0  LIST STUDY SYSTEM BUSES (0=NO, 1=YES)
 9:      0  LIST OPPOSING SYSTEM BUSES (0=NO, 1=YES)
10:      0  LIST STUDY SYSTEM TIE LINES (0=NO, 1=YES)
11:      0  ADD STUDY SYSTEM TIES TO MONITORED LINE LIST (0=NO, 1=YES)
12:      0  OUTPUT CODE (0=SUMMARY, 1=FULL)
13:      0  INTERCHANGE LIMIT OUTPUT CODE (0=INCREMENTAL, 1=TOTAL)
14:  24000  NUMBER OF ELEMENTS TO INCLUDE IN FLOW TABLES
15:  9999.  SUMMARY TABLE MAXIMUM IMPORT OR EXPORT (>0.)
16: 0.0000  SUMMARY TABLE MINIMUM DISTRIBUTION FACTOR MAGNITUDE
17:      5  SUMMARY TABLE MAXIMUM TIMES FOR REPORTING THE SAME ELEMENT
18:      0  APPLY SUMMARY MIN. DISTR. FACTOR TO SOLUTION REPORTS (0=NO, 1=YES)
19:    0.0  MINIMUM CONTINGENCY CASE PRE-SHIFT FLOW CHANGE
20: 0.0000  MINIMUM CONTINGENCY CASE DISTRIBUTION FACTOR CHANGE
21:      0  CONVERT RATINGS TO ESTIMATED MW RATINGS (0=NO, 1=YES)
ENTER PARAMETER CODE, NEW VALUE: 13,1
```

Want to see total interchange

```
SOLUTION PARAMETERS ARE:
 1:    0.5  MW MISMATCH TOLERANCE
 2:      1  BASE CASE RATING (1=RATEA, 2=RATEB, 3=RATEC)
 3:      1  CONTINGENCY CASE RATING (1=RATEA, 2=RATEB, 3=RATEC)
 4:   90.0  PERCENT OF RATING
 5:      0  LINE FLOW CODE (0=DC BASE CASE, 1=AC BASE CASE)
 6:      0  PHASE SHIFTER CODE (0=LOCKED, 1=REGULATING IN BASE CASES)
 7:      0  (0=IGNORE BASE CASE CONSTRAINTS IN CONTINGENCY CASES, 1=INCLUDE)
 8:      0  LIST STUDY SYSTEM BUSES (0=NO, 1=YES)
 9:      0  LIST OPPOSING SYSTEM BUSES (0=NO, 1=YES)
10:      0  LIST STUDY SYSTEM TIE LINES (0=NO, 1=YES)
11:      0  ADD STUDY SYSTEM TIES TO MONITORED LINE LIST (0=NO, 1=YES)
12:      0  OUTPUT CODE (0=SUMMARY, 1=FULL)
13:      1  INTERCHANGE LIMIT OUTPUT CODE (0=INCREMENTAL, 1=TOTAL)
14:  24000  NUMBER OF ELEMENTS TO INCLUDE IN FLOW TABLES
15:  9999.  SUMMARY TABLE MAXIMUM IMPORT OR EXPORT (>0.)
16: 0.0000  SUMMARY TABLE MINIMUM DISTRIBUTION FACTOR MAGNITUDE
17:      5  SUMMARY TABLE MAXIMUM TIMES FOR REPORTING THE SAME ELEMENT
18:      0  APPLY SUMMARY MIN. DISTR. FACTOR TO SOLUTION REPORTS (0=NO, 1=YES)
19:    0.0  MINIMUM CONTINGENCY CASE PRE-SHIFT FLOW CHANGE
20: 0.0000  MINIMUM CONTINGENCY CASE DISTRIBUTION FACTOR CHANGE
21:      0  CONVERT RATINGS TO ESTIMATED MW RATINGS (0=NO, 1=YES)
ENTER PARAMETER CODE, NEW VALUE: 5,1
```

Apply shift to initial ac flows

Figure 7.17. TLTG Interactive Dialog (Sheet 1 of 2)

```
SOLUTION PARAMETERS ARE:
 1:     0.5  MW MISMATCH TOLERANCE
 2:       1  BASE CASE RATING (1=RATEA, 2=RATEB, 3=RATEC)
 3:       1  CONTINGENCY CASE RATING (1=RATEA, 2=RATEB, 3=RATEC)
 4:    90.0  PERCENT OF RATING
 5:       1  LINE FLOW CODE (0=DC BASE CASE, 1=AC BASE CASE)
 6:       0  PHASE SHIFTER CODE (0=LOCKED, 1=REGULATING IN BASE CASES)
 7:       0  (0=IGNORE BASE CASE CONSTRAINTS IN CONTINGENCY CASES, 1=INCLUDE)
 8:       0  LIST STUDY SYSTEM BUSES (0=NO, 1=YES)
 9:       0  LIST OPPOSING SYSTEM BUSES (0=NO, 1=YES)
10:       0  LIST STUDY SYSTEM TIE LINES (0=NO, 1=YES)
11:       0  ADD STUDY SYSTEM TIES TO MONITORED LINE LIST (0=NO, 1=YES)
12:       0  OUTPUT CODE (0=SUMMARY, 1=FULL)
13:       1  INTERCHANGE LIMIT OUTPUT CODE (0=INCREMENTAL, 1=TOTAL)
14:   24000  NUMBER OF ELEMENTS TO INCLUDE IN FLOW TABLES
15:   9999.  SUMMARY TABLE MAXIMUM IMPORT OR EXPORT (>0.)
16:  0.0000  SUMMARY TABLE MINIMUM DISTRIBUTION FACTOR MAGNITUDE
17:       5  SUMMARY TABLE MAXIMUM TIMES FOR REPORTING THE SAME ELEMENT
18:       0  APPLY SUMMARY MIN. DISTR. FACTOR TO SOLUTION REPORTS (0=NO, 1=YES)
19:     0.0  MINIMUM CONTINGENCY CASE PRE-SHIFT FLOW CHANGE
20:  0.0000  MINIMUM CONTINGENCY CASE DISTRIBUTION FACTOR CHANGE
21:       0  CONVERT RATINGS TO ESTIMATED MW RATINGS (0=NO, 1=YES)
ENTER PARAMETER CODE, NEW VALUE:
```

No other changes, default parameters OK

```
WORKING CASE HAS LARGEST MISMATCH OF      0.00 MW AT BUS   151 [NUCPANT   500]

ENTER OUTPUT DEVICE CODE:
 0 FOR NO OUTPUT     1 FOR CRT TERMINAL
 2 FOR A FILE        3 FOR QMS PS2000
 4 FOR QMS_PS800     5
FOR HARD COPY TERMINAL
 6 FOR ALTERNATE SPOOL DEVICE: 4
ENTER NUMBER OF COPIES (UP TO 6): 1
Opened queue for ps
ENTER DISTRIBUTION FACTOR FILENAME: savnw.dfax

THESE SUBSYSTEMS WERE SPECIFIED:
NUMBER <-- NAME --> BUSES
    1  STUDY            6
    2  WEST             8
    3  EAST             6
ENTER STUDY SYSTEM NUMBER: 1
ENTER OPPOSING SYSTEM NUMBER: 2
```

Specify the systems studied here

```
STUDY SYSTEM GENERATION IS        1500.0 MW
OPPOSING SYSTEM GENERATION IS      348.9 MW
STUDY SYSTEM NET INTERCHANGE IS    282.6 MW
ENTER STUDY SYSTEM GENERATION SHIFT: -100
ENTER INTERFACE LABEL FOR INTERFACE LIMITS SUMMARY TABLE: west
ENTER INTERFACE LABEL FOR INTERFACE LIMITS SUMMARY TABLE: east
INTERFACE EAST FLOW INSENSITIVE TO GENERATION SHIFT
ENTER INTERFACE LABEL FOR INTERFACE LIMITS SUMMARY TABLE:

Issue: prf PST001.DAT -nc -delete -headers off -trans -banner off -pr ps

ACTIVITY?
```

Figure 7.18. TLTG Interactive Dialog (Sheet 2 of 2)

7.5.8. Activity POLY

Activity POLY is a variation of the transfer limit analysis activity TLTG. This activity considers a single study system and two opposing systems. It uses all the same data input files as TLTG. This activity produces a graphic display, as shown in Figure 7.19, “Activity POLY Output”, which shows the dependence of limiting interchange with each opposing system on the interchange with the other. The generation shift used for this example is -100. The output shows feasible areas of interchange and allows the engineer to then decide actual interchange based on economics.

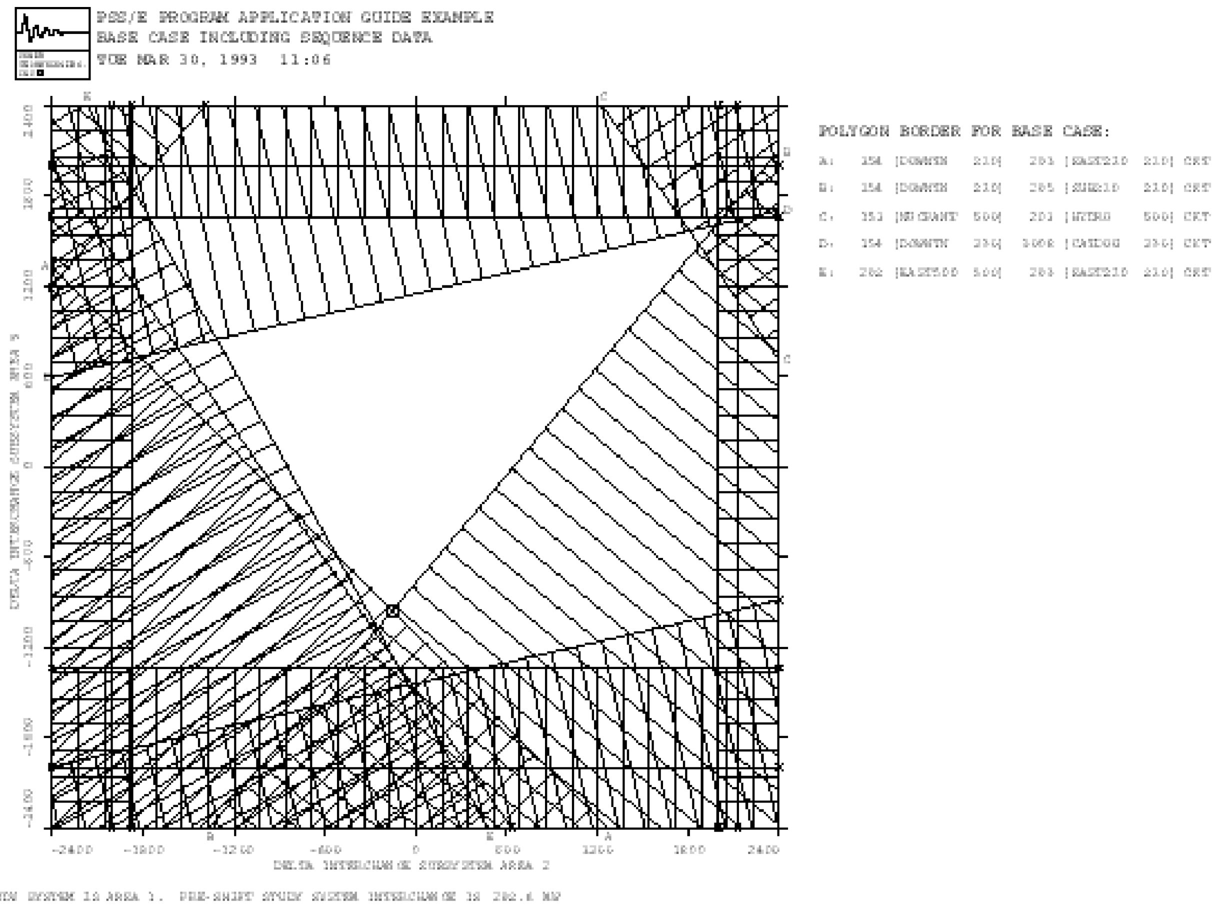


Figure 7.19. Activity POLY Output

7.5.9. Activity INLF

The design and operation of interconnected systems to limit the frequency effects of cascading outages has been receiving more attention. The linearized activities earlier described help to analyze cascading by giving the user an approximate checking for overloading, one cause of cascading. Activity INLF has been added to look at various time frames of the system after a disturbance or system change.

The standard power flow solutions include the following assumptions:

- All changes in losses and generation load balance will come from remote sources (swing bus).
- Operators will adjust generator voltage regulators to maintain reactive loadings within unit continuous capability (var limits are applied).
- Operators or automatic tap controls will move voltage and phase taps to restore controlled voltage or taps.
- Load KW and kvar will be restored to initial values by equipment not normally represented.

INLF was written to help represent, in the posttransient time, other effects such as governor action or automatic generation control, and other items with a time frame that may stress a system.

There are two redispatches in INLF labeled inertial power flow and governor response power flow solution. The first is intended to give a quick approximation to system effects in approximately the first 0.5 seconds following a disturbance. In this solution, excitation systems and governor system effects are minimal. Generation changes are assumed to be influenced solely by inertial effects. The assumptions of the inertial solution are:

1. Plant operators and exciters have not adjusted any voltage set points. Therefore, if a unit was on var limits before, the voltage from the previous solution is now the desired setpoint. Also var limits at all machines are ignored.

2. Most automatic adjustment equipment has not yet responded, which results in having automatic tap adjustment, phase-shift angle adjustment, and area interchange disabled.

3. Switched shunts respond quickly and are active.

The governor response solution is intended to represent the system several seconds after an event. For this solution, governors and exciters have brought the system back to a steady state. New generator powers are determined by governor droop and damping characteristics. For this solution, the following assumptions are made:

1. Exciters have brought generations back to schedule, i.e., var limits are enabled.

2. All automatic adjustments, except area interchange control, are active. Therefore, tap adjustment and phase-angle adjustment and switched shunt are enabled.

Note that proper choice of D, the turbine damping factor, and R, the governor permanent droop, can turn the governor response solution to one based on economic participation factors. The user of this activity can call it with the OPT suffix and override the default adjustments application of reactive power limits and, therefore, model any desired time frame. This activity, which was written to include cascading, handles up to 10 system islands all of which must have a generator. The key items to remember when using the INLF are:

1. It is illegal to run the activity twice in a row because frequency is based on initial generator powers.

2. It modifies frequency-dependent parameters in the working case so subsequent use of the case should be done with care, if at all.

Because data used by this activity is often the same that is used in dynamics, activity RWDY, which is available from dynamics, will create an input file for it. In general, the data created for R, PMAX, and PMIN is obvious. Table 7.2, "Data Assumption of RWDY" lists some of the data created for models when it is not obvious.

Table 7.2. Data Assumption of RWDY

Model Name	R	PMAX	PMIN
WESGOV	1./KP	0.	0.
WEHGOV	1./KP	GMAX	GMIN
WSHYDD	1./KG	PMAX	PMIN
WSHYGP	1./KG	PMAX	PMIN

7.5.10. Activity GRPG

Activity GRPG was designed to aid the user in making reports of interchange transactions. The activity basically relies on the user to design a diagram and gives the user the capability of getting into the PSS®E database to print many of the traditionally desired parameters. GRPG also allows a user defined diagram to be superimposed on a one-line diagram. Its dialog is straightforward. Figure 7.20, "Example GRPG Input File (Sheet 1 of 2)" shows a sample input file to create the report shown in Figure 7.22, "GRPG Output" for the sample system that has been used in this transfer analysis section of the manual.

7.5.11. Activity PSEB

Activity PSEB allows English-like commands to be written so that routine production runs may be easily set up in batch. It is very useful in transfer analysis because the user is capable of setting up many contingency cases and streamlining output.

PSEB has the ability to evaluate expressions involving both data arising within the control of the program and data from the PSS®E working files. It also gives the user a capability of looping and testing based on expressions.

```
COMMENT         ...SAMPLE GRPG DATA FILE...
COMMENT        DISPLAYS AREA INTERCHANGE PLUS
COMMENT      AREA GENERATION AND LOAD SUMMARIES

* DEFINE MACROS

DEFINE MACRO AREANAME
* ANNOTATE AREA NUMBER
* %1% IS THE TEXT TO BE OUTPUT
* %2%,%3% ARE THE X,Y COORDINATES FOR ANNOTATION
SET TEXT HEIGHT TO 0.25
SET TEXT ANGLE TO 90.
JUSTIFY TEXT CENTERED
SET LINE WIDTH TO 2
SET LINE COLOR TO 2
WRITE %1% AT %2%,%3%
ENDMACRO

DEFINE MACRO ANNOTATE
* ANNOTATE AREA GENERATION AND LOAD TOTALS
* %1% IS THE AREA NUMBER
* %2%,%3% ARE THE X,Y COORDINATES FOR ANNOTATION
SET LINE WIDTH TO 1
SET LINE COLOR TO 1
SET TEXT HEIGHT TO 0.1
SET TEXT ANGLE TO 90.
JUSTIFY TEXT LEFT
LET &LOADP = THE LOAD FOR AREA %1%
LET &GENP = THE GENERATION FOR AREA %1%
WRITE 'LOAD ' &LOADP ' MW<CR>      ' &LOADQ   ' MVAR<CR><CR>' AT %2%,%3%
WRITE 'GEN  ' &GENP  ' MW<CR>      ' &GENQ    ' MVAR
ENDMACRO

* DECLARE VARIABLES

DECLARE STRING &HEAD1, &HEAD2
DECLARE REAL &LOADP, &LOADQ, &GENP, &GENQ, &INTP, &INTQ

* AREA 1

SET LINE WIDTH TO 3
SET LINE COLOR TO 3
DRAW LINE FROM 0.25,2.7 TO 0.25,4.5
DRAW LINE TO 1.75,4.5
DRAW LINE TO 1.75,6
DRAW LINE TO 3.3,6
DRAW LINE FROM 3.7,6 TO 5.5,6
DRAW LINE TO 5.5,9.75
DRAW LINE TO 6.75,9.75
DRAW LINE TO 6.75,2.7
DRAW LINE TO 3.7,2.7
DRAW LINE FROM 3.3,2.7 TO 0.25,2.7
INVOKE MACRO AREANAME USING 'AREA 1' 2.5,4.25
INVOKE MACRO ANNOTATE USING 1 4.5,3.25

* AREA 2

SET LINE WIDTH TO 3
SET LINE COLOR TO 3
DRAW LINE FROM 0.25,5 TO 0.25,9.75
DRAW LINE TO 5,9.75
DRAW LINE TO 5,6.5
DRAW LINE TO 3.7,6.5
DRAW LINE FROM 3.3,6.5 TO 1.25,6.5
DRAW LINE TO 1.25,5
DRAW LINE TO 0.25,5
INVOKE MACRO AREANAME USING 'AREA 2' 1.0,8.25
INVOKE MACRO ANNOTATE USING 2 2.0,7.4

* AREA 5

SET LINE WIDTH TO 3
SET LINE COLOR TO 3
DRAW LINE FROM 0.25,0.25 TO 0.25,2.25
DRAW LINE TO 3.3,2.25
DRAW LINE FROM 3.7,2.25 TO 6.75,2.25
DRAW LINE TO 6.75,0.25
DRAW LINE TO 0.25,0.25
INVOKE MACRO AREANAME USING 'AREA 5' 1.0,1.25
INVOKE MACRO ANNOTATE USING 5 2.0,0.39
```

Figure 7.20. Example GRPG Input File (Sheet 1 of 2)

```
* INTERCHANGE FROM AREA 1 TO AREA 2

LET &INTP = THE INTERCHANGE FROM AREA 1 TO AREA 2
IF &INTP >= 0.
   ROTATE PLOT 0 DEGREES AROUND 3.3,5.7
   INCLUDE intchgu WITH OFFSET 3.3,5.7 AND SCALE 1.0
ELSE
   LET &INTP = THE INTERCHANGE FROM AREA 2 TO AREA 1
   ROTATE PLOT 180 DEGREES AROUND 3.7,6.8
   INCLUDE intchgd WITH OFFSET 3.7,6.8 AND SCALE 1.0
ENDIF

* INTERCHANGE FROM AREA 1 TO AREA 5

LET &INTP = THE INTERCHANGE FROM AREA 1 TO AREA 5
IF &INTP >= 0.
   ROTATE PLOT 180 DEGREES AROUND 3.7,3.0
   INCLUDE intchgd WITH OFFSET 3.7,3.0 AND SCALE 1.0
ELSE
   LET &INTP = THE INTERCHANGE FROM AREA 5 TO AREA 1
   ROTATE PLOT 0 DEGREES AROUND 3.3,2.0
   INCLUDE intchgu WITH OFFSET 3.3,2.0 AND SCALE 1.0
ENDIF

* RESET ROTATION

ROTATE PLOT 0 DEGREES AROUND 0,0

* SHADE AROUND AREAS

SET SHADING PATTERN TO 3
SET SHADING OUTLINE VISIBLE

APPEND BOX FROM 0.0,0.0 TO 7.5,10.0 WITH RADIUS 0.1
APPEND LINE FROM 0.25,0.25 TO 0.25,2.25
APPEND LINE TO 3.3,2.25
APPEND LINE TO 3.3,2.7
APPEND LINE TO 0.25,2.7
APPEND LINE TO 0.25,4.5
APPEND LINE TO 1.75,4.5
APPEND LINE TO 1.75,6
APPEND LINE TO 3.3,6
APPEND LINE TO 3.3,6.5
APPEND LINE TO 1.25,6.5
APPEND LINE TO 1.25,5
APPEND LINE TO 0.25,5
APPEND LINE TO 0.25,9.75
APPEND LINE TO 5,9.75
APPEND LINE TO 5,6.5
APPEND LINE TO 3.7,6.5
APPEND LINE TO 3.7,6.0
APPEND LINE TO 5.5,6
APPEND LINE TO 5.5,9.75
APPEND LINE TO 6.75,9.75
APPEND LINE TO 6.75,2.7
APPEND LINE TO 3.7,2.7
APPEND LINE TO 3.7,2.25
APPEND LINE TO 6.75,2.25
APPEND LINE TO 6.75,0.25
APPEND LINE TO 0.25,0.25
APPEND BOX FROM 6.75,1.8 TO 7.5,8.2

SHADE ACCUMULATED POLYGONS

* ADD CASE TITLE, DATE AND TIME

JUSTIFY TEXT LEFT
LET &HEAD1 = THE CASE TITLE
SET TEXT HEIGHT TO 0.1 INCHES AND ANGLE TO 90 DEGREES
WRITE &HEAD1 '<CR>' &HEAD2 '<CR>' AT 7.0,2.0
WRITE %DATE% '  ' %TIME%
SET TEXT ANGLE TO 0


END
```

Figure 7.21. Example GRPG Input File (Sheet 2 of 2)

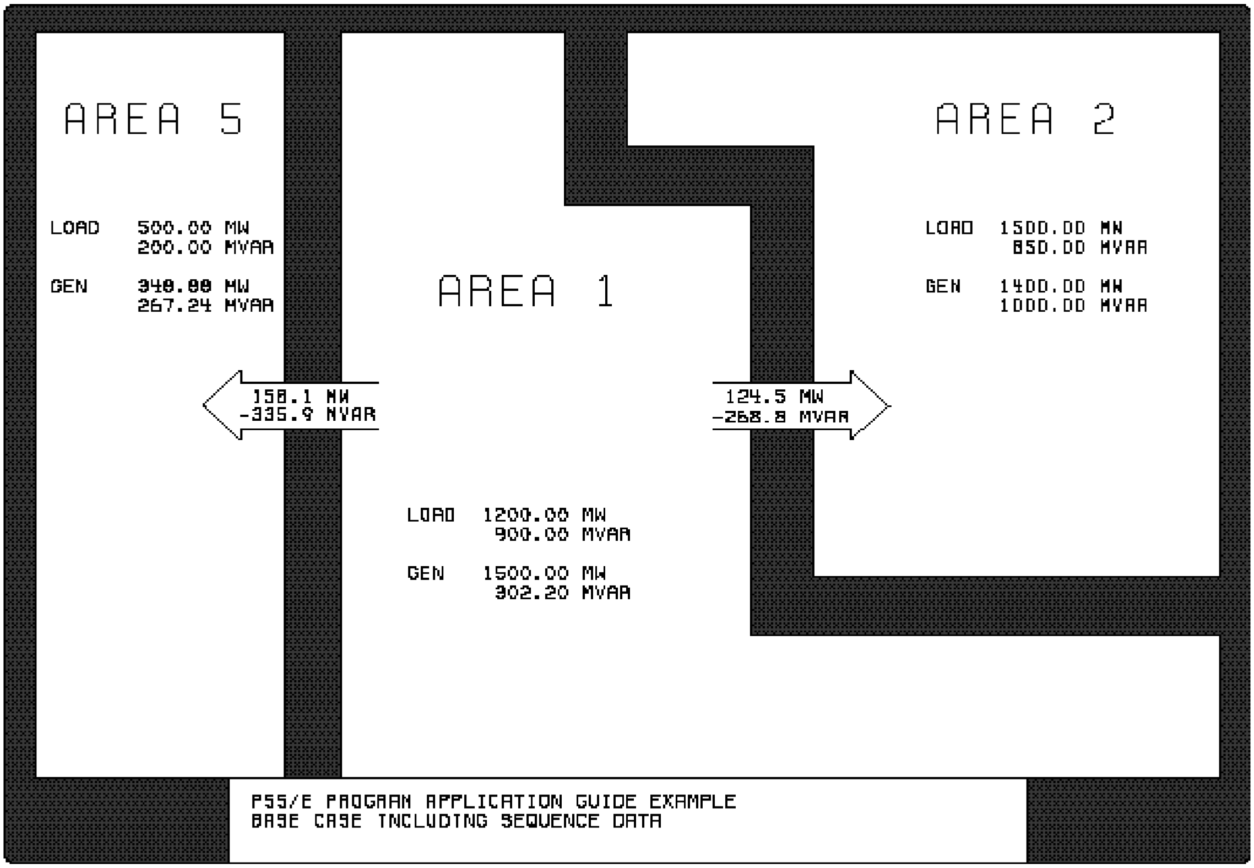


Figure 7.22. GRPG Output

7.6. General

Chapter 6, *Basic Power Flow Activity Applications* describes the use of PSS®E activities in the basic task of setting up a power system model and obtaining a power flow solution. The construction and solution of a single, initial, or base case, power system model is a key step in the execution of a study. It is usually followed up, though, by a large number of solutions of modified or alternative system models in which transmission switchings, load changes, generation changes, and other operating condition changes are considered. The rapid and efficient implementation of system model changes is facilitated by a set of model manipulation activities.

7.6.1. Activities CHNG and MBID

The most basic model manipulation activity is CHNG, which allows the user to change the value of any system parameter in the working file. Activity MBID allows the user to change machine and branch identifiers. CHNG functions at the most selective level; that is, it changes the value of only one parameter at a time. Hence, while it can be used to make any number of similar or diverse parameter adjustments, CHNG is an inconvenient tool for implementing a model change involving the alteration of many items of data. Such changes, increasing of all loads by 10%, for example, may be handled much more conveniently by the special activities described in the remainder of this section.

7.6.2. Activity RDCH

Often a user will want to make numerous changes to a case. These changes can be one specific type of data, such as real and reactive loads at a bus. It would be inconvenient for the user to interactively change loads at several buses, especially if those load changes were the output of other programs. Input to activity RDCH is nearly identical to activity READ, making mass changes convenient; it uses whatever data is in the current working files for default values.

7.6.3. Activity MOVE

While activities RDCH and CHNG are useful in implementing several additions and changes to a system model, they are not convenient to use when the system configuration must be modified. Activity MOVE allows the user to move ac branches, switched shunts, single machines, and entire plants from one bus to another.

Plan A of Figure 7.23, “Rerouting of Circuit X” is a system configuration being considered by a utility. Plan B, in which circuit *X* is connected directly from NT MOUNT to ST CITY, is an optional configuration. The rerouting of the line is made very easy through the interactive dialog of activity MOVE.

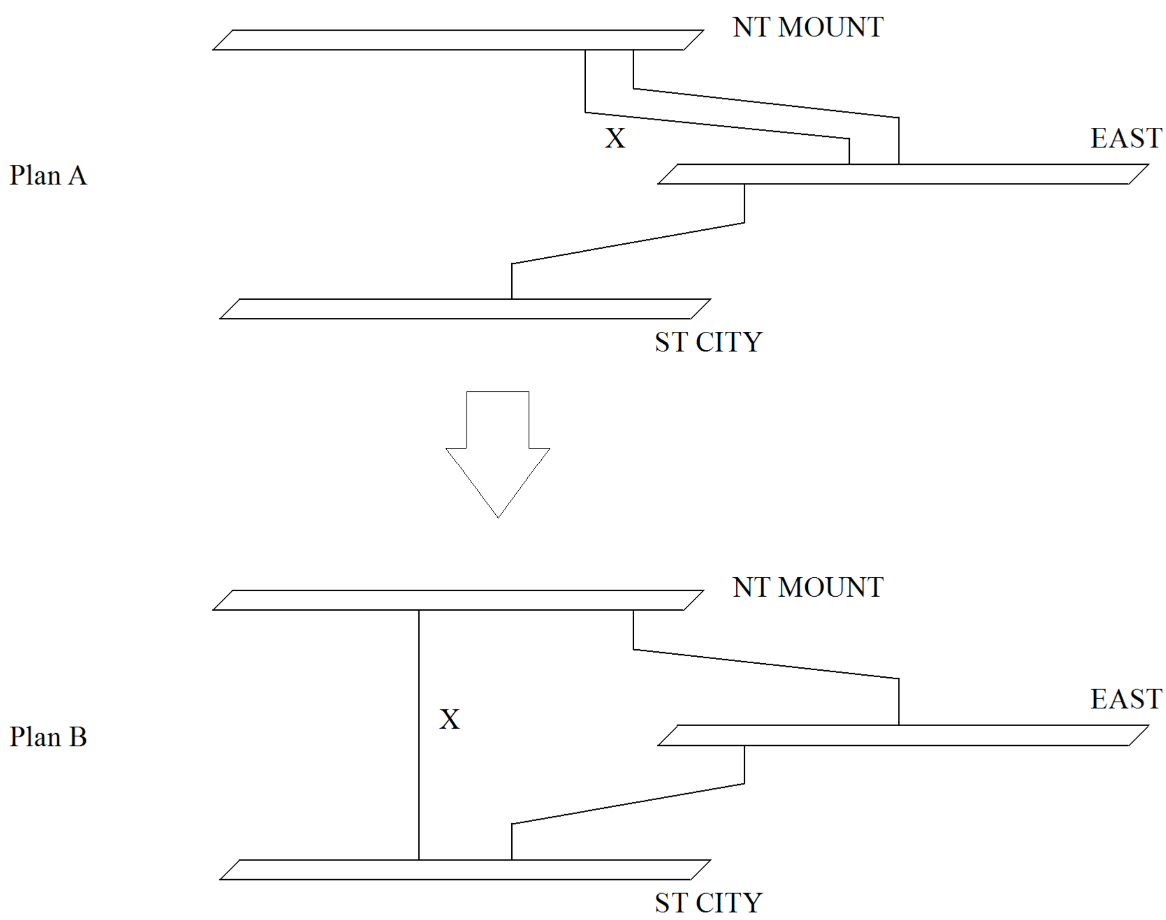


Figure 7.23. Rerouting of Circuit X

7.7. Load Voltage Characteristics

7.7.1. Changing Load Models

Normal practice in power flow work is to assume that distribution system tap changers and voltage regulators have brought customer voltages to nominal values and, hence, that load at the buses represented in the power flow case may be treated as a constant real and reactive power demand. It is recommended, therefore, that the reference load as defined in Section 6.4.2 Load Data be used to model loads in power flow calculations so that load is treated as constant MVA from one power flow case to the next.

Treating loads as purely constant MVA at the reference load value is not acceptable in switching studies and dynamic simulations because time delays in distribution voltage-regulating devices prevent them from adjusting customer voltages in the period of interest. In these studies, the voltage dependence of load should be recognized by breaking the reference load into its components with different voltage characteristics. The network solutions of PSS®E recognize load components with constant MVA, constant current, and constant admittance characteristics as discussed in Sections 5.5.1 and 6.4.2.

The manipulation of system loads from one of voltage-dependent components to another is handled by activities CONL and RCNL.

7.7.2. Activity CONL

Activity CONL takes constant MVA load and reassigns it as constant current or constant admittance load as shown in Figure 7.24, “Load Reallocation at a Bus by Activity CONL”. A fraction of the constant MVA load at each bus is transferred to each of the other two load characteristics, according to the rules

$$S_I = S_i + \frac{aS_p}{v}$$

$$S_Y = S_y + \frac{bS_p}{v^2}$$

$S_P = S_p \times (1 - a - b)$

where

S_p

Original constant MVA load.

S_i

Original constant current load.

S_Y

Original constant shunt admittance load.

S_P

Final constant MVA load on bus (real or reactive).

S_I

Final nominal constant current load on bus (real or reactive).

S_Y

Final nominal constant shunt admittance load on bus (real or reactive).

a,b

Load transfer fractions, (a + b) < 1 (Real and reactive load may be allocated by different a and b values.)

v

Magnitude of bus voltage when load conversion is made.

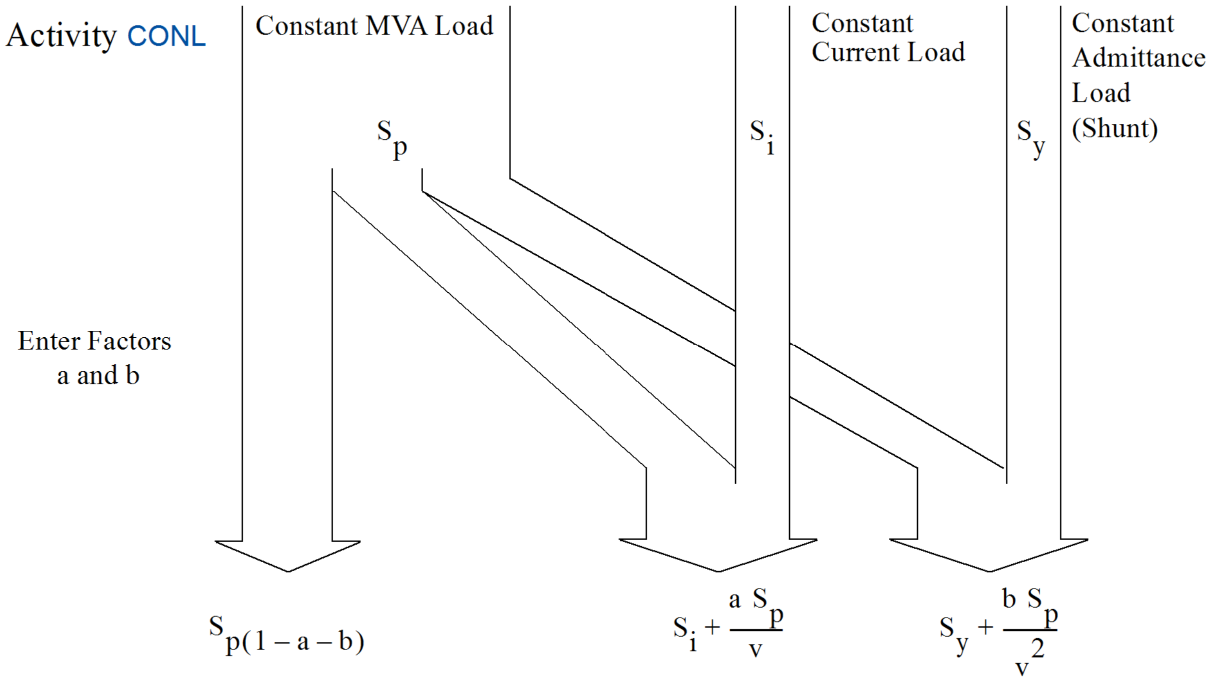


Figure 7.24. Load Reallocation at a Bus by Activity CONL

Because the above formulation uses the present estimate of bus voltage in its reallocation of load among the three components, CONL should be run only when the working case contains a valid solved power flow or, if appropriate, a flat voltage estimate vector.

On the first application of CONL to a power flow case, the constant MVA load component is initialized to equal the reference load, while the constant current and constant admittance components are set to zero. The first execution of CONL sets a flag so that all subsequent applications of CONL to the case will bypass this step and use the present values of the load components as the starting point in the above allocation.

The initial execution of CONL prevents activity CHNG from accessing or changing the reference load, but instead allows CHNG to access and change the constant MVA, constant current, and constant admittance components.

Changing load components with CHNG after execution of CONL is not reflected by corresponding change in the reference load. The reference load can be updated to correspond exactly to the present sum of the load components by the use of activity RCNL as covered in Section 7.7.3, “Activity RCNL”.

CONL recognizes the selection suffixes ALL, AREA, ZONE, KV, OWNER and OPT; it applies its conversion to all loads in the system section defined by the selection dialog.

7.7.3. Activity RCNL

While the breaking of the reference load into components by activity CONL is not completely reversible, a partial reversal is sometimes desirable and can be handled by activity RCNL, illustrated in Figure 7.25, “Load Collection and Reallocation by Activity RCNL”. RCNL first collects all load back into a single constant MVA load and then reallocates it into constant MVA, constant current, and constant admittance components in the same manner as activity CONL.

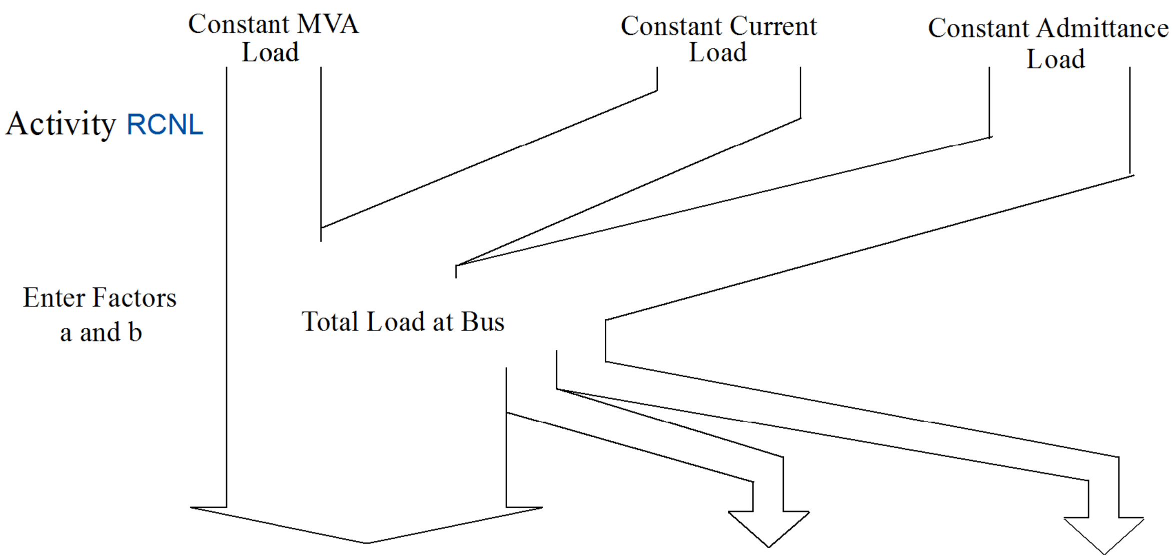


Figure 7.25. Load Collection and Reallocation by Activity RCNL

RCNL has three modes of operation as described below. The symbols used are defined in Section 7.7.2, “Activity CONL” with the addition of S_r, the real or reactive component of reference load.

1. Allocation of load on the basis of present bus voltage and present actual load. In this mode, RCNL first collects all load into the constant MVA component by

   $S_P = S_p + vS_i + v^2S_y$

   $S_r = S_P$

   $S_i = 0 \ S_y = 0$

   and then reallocates it by the formula

$$S_I = \frac{aS_r}{v}$$

$$S_Y = \frac{bS_r}{v^2}$$

$S_P = S_r\,(1 - a - b)$

The reference load is updated to equal the present total load on the bus.

2. Allocation of load on the basis of present bus voltage and reference load. In this mode RCNL ignores the present actual load as given by the load components and runs the same allocation as an *initial* application of CONL; that is

$$S_I = \frac{aS_r}{v}$$

$$S_Y = \frac{bS_r}{v^2}$$

$S_P = S_r\,(1 - a - b)$

The reference load is unchanged.

3. Allocation of load on the basis of unity voltage. This mode of RCNL is identical to mode 1, except that the present voltage at the bus is ignored and a voltage value of unity is used in its place; that is

$S_P = S_p + S_i + S_y$

$S_r = S_P$

$S_I = aS_r$

$S_Y = bS_r$

$S_P = S_r\,(1 - a - b)$

The reference load is updated to equal the new total load that the bus would carry at unity voltage.

Activity RCNL may be used with zero values of the fractions *a* and *b*; in this case mode 1 or mode 2 can be the equivalent to the complete undoing of CONL if the working case contains the same voltage vector that was present in the application of CONL.

Note that modes 1 and 3 of RCNL recognize any changes that have been made to the load components S_p, S_i, and S_y because the last execution of CONL or RCNL. Mode 2 of RCNL, however, ignores any such changes and returns the bus total load to its reference value as last established by RCNL, SCAL, or by power flow activities prior to the initial application of CONL.

7.8. Open Access and Transmission Pricing Activities

The electric utility industry restructuring, prevalent in the United States and many other countries in the close of the twentieth Century has generated interest in analytic tools for transaction processing. Open Access and Pricing Activities (OPA) have been introduced to the power flow processor to aid in assessing transaction feasibility, and cost allocation. The transaction feasibility assessment is supported by the transaction impact calculator, activity IMPC, and the line loading relief calculator, activity LLRF. The transmission cost allocation technique mandated by the Public Utility Commission of Texas for computing the impact fee component of transmission usage fee is provided in the allocation function, activity ALOC. Transmission loss allocation techniques are provided as well.

7.8.1. Transaction Data and Data Management

OPA requires a power flow model that has previously been solved to a valid DCLF solution. This model is then augmented with transaction data, including transaction event definitions.

A transaction event consists of the following attributes:

- A unique number used for reporting, for defining sequence order, and for referring to transactions in program dialog.
- Service status.
- A magnitude value in MW.
- An alpha numeric label.
- A curtailment value in MW.
- A list of participating network buses.

Buses participate in a transaction as points of power injection into or demand from the power system network. An in-service transaction of nonzero magnitude will result in power flows on transmission branch elements. Load and generation input values are associated with each participating bus. A bus participates as a power injection point when its generation value is greater than zero or its load value is less than zero. A bus participates as a power demand point when its load value is greater than zero or its generation value is less than zero. The injection or demand magnitude is a function of the transaction magnitude, the load and generation values, and for some functions, the transaction curtailment value.

Transmission cost and loss allocation methods are concerned with branch ownership and control area, respectively. The flow or loss impact of a branch is computed and accumulated by owner or control area.

Transaction data may be introduced into the PSS®E working memory by use of the command line activity REMM or by GUI dialog, which provides for entry to the REMM activity from a menu selection and provides for a transaction event data editor. The transaction event data editor may be employed to introduce transaction event data when none has been previously introduced, but the participation flag (refer to the description of activity REMM in the *PSS®E Program Operation Manual)* will default to 0 and cannot be altered by dialog with the editor.

After being introduced into working memory, transaction data may be modified and maintained with the GUI transaction event data editor or with Activity REMM,CH. Transaction data introduced to PSS®E working memory is volatile. It is not maintained with the PSS®E working files. To avoid losing changes made to the transaction data it should be saved to a file using activity RWMM.

7.8.2. Activity IMPC

The transaction impact calculator, activity IMPC, computes the incremental MW flow impact on a set of monitored elements due to a single transaction event. It uses a distribution factor data file created by activity DFAX to define the monitored element set. It employs the transaction magnitude, without regard to the curtailment value, to determine the power injections and demands at participating buses. It employs the linearized solution technique to compute the incremental element flows. Regulating in-service phase shifting transformers have zero incremental MW flow.

IMPC produces a report that illustrates the incremental MW flow impacts on each of the monitored elements, along with the initial available transfer capability (ATC) for the element and a final ATC that is adjusted for the flow impact due to the transaction. For monitored interfaces, a value is provided that illustrates the maximum transaction magnitude that can be supported by the element's ATC.

7.8.3. Activity LLRF

The line loading relief calculator, activity LLRF, provides a menu of functions related to computing transaction magnitude adjustments that result in feasible monitored element branch MW flows. It uses a distribution factor data file created by activity DFAX to define the monitored element set. It employs the transaction magnitude and the curtailment value to determine the power injections and demands at participating buses. It employs the linearized solution technique to compute monitored element distribution factors and the incremental element flows. Regulating in-service phase shifting transformers have zero incremental MW flow. It reflects adjustments in the transaction curtailment value.

The user may specify the desired MW flow increment on a monitored element. This incremental flow value may, for example, represent the amount by which the element is overloaded. Activity LLRF will report adjustments to transaction magnitudes required to satisfy this incremental flow. These transaction adjustments may be limited to transaction curtailment (i.e., increases in transaction curtailment value magnitude not to exceed the transaction magnitude value) or transaction restoration (i.e., decreases in transaction curtailment value magnitude).

Transactions participate in adjustment as a function of their transaction priority and the applied adjustment method. Four adjustment methods are available: first in last out, decreasing order by distribution factor magnitude, pro rata by distribution factor magnitude, and pro rata by the product of distribution factor with transaction schedule (transaction magnitude less curtailment). Transactions are excluded from adjustment when their distribution factor magnitude is less than a user-specified tolerance. Individual events are grouped by priority. The curtail transactions function proceeds to investigate the priorities from lowest to highest priority number until the incremental flow target is satisfied or all transaction priority groups are exhausted. The restore transactions function proceeds to investigate the priorities from highest to lowest priority number until the incremental flow target is satisfied or all transaction priority groups are exhausted.

LLRF produces reports that illustrate:

- Transaction adjustments that result in a specified incremental flow on a selected monitored element.
- Distribution factors (i.e., sensitivity of monitored element MW flow to transaction magnitude) for all monitored elements and transaction events.

7.8.4. Activity ALOC

Transmission allocation reports and related transaction event worksheets are generated with activity ALOC. These reports provide an accounting basis that illustrates the impact on the transmission system due to transaction events. The accounting basis may be used to allocate embedded transmission costs or controls area losses among the various transaction events making use of the transmission networks.

Activity ALOC employs the Vector Absolute MW-Mile (VAMM) method to produce the transmission embedded cost allocation. MW-mile methods are techniques for ascribing the use of the electric power transmission system among the various beneficiaries. These are accounting practices that rely on engineering analysis to determine the basis. This basic accounting unit is the product of branch MW flow with branch length.

The VAMM method determines the impact for each individual transaction event by perturbing each bus generation associated with the event against the associated event load. For each perturbation, the absolute value of change in branch flow (i.e., change from the initial condition power flow model) is multiplied by the branch length in miles, and this result is accumulated in the event's MW-Mile vector, one entry for each branch owner of the power flow model (i.e., each facility owner) as illustrated in Equation 7.4.

$$MWM_{ij} = \sum_{k}^{NAG_j} \sum_{l}^{NAL_i} |\Delta P_l| L_l \tag{7.4}$$

where:

MWM_{ij}

MW-Mile impact for the i^{th} owner and j^{th} transaction event.

NAG_j

Number of j^{th} transaction event associated generators.

NAL_i

Number of branches owned by the i^{th} owner (transmission facility owner).

Δ

P

Incremental MW branch flow due to perturbing MW generation.

L

Branch length in miles.

The union of these vectors for each transaction event forms an aggregate MW-Mile allocation matrix. This matrix is then employed in a spreadsheet program to allocate each facilities owner's cost of service among the transaction events, each transaction event being responsible for costs in proportion to the ratio of its impact to the total impact on that facilities owner.

The aggregate MW-Mile allocation matrix may be constructed directly by using a procedure that repeatedly perturbs the participating generation buses for each of the various transaction events, computing the flow impact and accumulating the impacts into the appropriate matrix positions. The aggregate matrix may also be constructed as the union of impact vectors, one for each transaction, where these impact vectors are computed by a transaction event worksheet.

Transaction event worksheets compute an impact vector as a product of generation vector with a coefficient matrix; a generation on MW-Mile shift factor matrix. An element of this coefficient matrix is the sensitivity of the MW-mile impact on a facility owner to the generation output of a participating bus. The matrix elements have units of MW-Mile per MW. The inner summation of Equation 7.4 is used to compute the elements of the generation on MW-Mile shift factor matrix, where the generation perturbation magnitude is 1.0 MW. Computing the aggregate MW-Mile allocation matrix in this manner, while more involved, provides for analyzing the impact of various generation dispatch scenarios with the spreadsheet program. A generation vector can be selected that satisfies the demand and minimizes the transmission cost.

Activity ALOC can produce information for allocating control area transmission losses among the various transaction events. Two loss allocation methods are available, the Vector Absolute MW-Ohm (VAMO) and the Vector Sum MW-Ohm (VSMO). As with the MW-Mile methods, these MW-Ohm methods are accounting practices that rely on engineering analysis to determine the basis. This basic accounting unit is the product of branch MW flow with branch per unit resistance.

The computation required to produce both the VAMO and the VSMO aggregate allocation matrices is that described in equation (7.4) modified as follows:

- Branch length is replaced by branch per unit resistance.
- The inner summation is over branches belonging to control area as opposed to branch owners.
- For VSMO, only the signed value as opposed to the absolute value of incremental branch flow is employed.

Activity ALOC may be directed to produce the aggregate allocation matrix for any of the VAMM, VAMO, or VSMO methods. It may also be directed to report the generation vector and the shift factor matrix for both the VAMM and VAMO methods. Activity ALOC may be directed to report the summation of branch mileage for each facility owning area. This mileage report is useful for checking the integrity of the mileage and joint branch ownership data. Employing the GUI program dialog will result in reports that are in a format conducive for importing this data into a spreadsheet program. From command line dialog the user should employ ALOC,SS to ensure that resulting reports are formatted for spreadsheet input.

7.9. Switching

7.9.1. Single Switching

Simple switchings, such as opening transmission lines or taking generators out-of-service, are handled by CHNG. The following general points apply to the use of activity CHNG:

- Switching a transmission line or transformer requires only changing its status. Changing branch status is equivalent to opening or closing a circuit breaker at both ends of the branch. Changing branch status changes no branch data.

- *All* generators located at a bus may be taken out-of-service by changing the bus type code from 2 or 3 to 1.

- Individual generators may be started or stopped by changing their generator status bits.

- The number of generators online in a hydro plant with many identical units is handled by changing base MVA, MBASE. The output of the generators that are running in the plant must be changed, correspondingly, by changing the real power output, PGEN, and the reactive power limits, QMAX and QMIN.

- All other system switching operations are handled by changing values of appropriate parameters. Switching a bus-connected shunt reactor, for example, is achieved by changing the values of the appropriate shunt parameters, GSHUNT and BSHUNT.

The switching of three-terminal lines usually involves changing the status of three branches, thus leaving the midpoint bus isolated, as shown in Figure 7.26, “Isolation of Mid-Point Bus on Opening of a Three-Winding Transformer Isolated Bus Must Have Type Code Changed to 4”. This isolated bus must have its type code changed to 4.

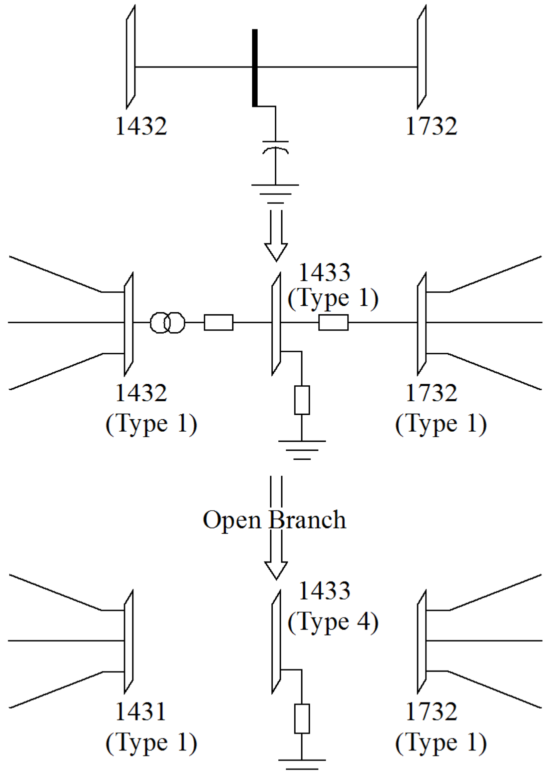


Figure 7.26. Isolation of Mid-Point Bus on Opening of a Three-Winding Transformer Isolated Bus Must Have Type Code Changed to 4

7.9.2. Activity DSCN

While the transformer opening operation shown in Figure 7.26, "Isolation of Mid-Point Bus on Opening of a Three-Winding Transformer Isolated Bus Must Have Type Code Changed to 4" can be handled with activity CHNG, it would involve a lengthy dialog to change three branch statuses and to change the type code of bus 1433 to 4. The same operation could be handled more conveniently by activity DSCN. Activity DSCN disconnects all equipment connected to specified buses; it changes the status of all branches connected to the bus to zero (out-of-service) and changes the type code of the bus to 4.

While DSCN facilitates the opening of all branches connected to a bus, it must be used with care regarding the isolation of other buses. Consider the opening of the three-winding transformer modeled by three branches with tertiary-connected synchronous condenser as shown in Figure 7.27, "Isolation of Transformer Mid-Point Bus and Tertiary Bus by Opening of Transformer". Opening the branches that represent the transformer may be accomplished by applying DSCN to bus 1404 only. This is not satisfactory, however, because it isolates the Type 2 synchronous condenser bus, 1402, but does not change its type code to 4. Two correct dialogs are shown in Figure 7.29, "Use of DSCN and CHNG to Open Three-Winding Transformer as in Figure 7.27, "Isolation of Transformer Mid-Point Bus and Tertiary Bus by Opening of Transformer"" and Figure 7.30, "Use of SPLT to Split a Single Bus into a Pair of Buses". It is advisable to follow execution of DSCN by activity TREE to ensure that no buses have inadvertently been left isolated with an improper type code.

7.9.3. Activity RECN

Activity RECN places in service all equipment connected to specified buses; it changes the status of all branches between the user-specified bus and all nontype 4 buses to one (in service) and changes the type code of the bus to 1 or 2, as appropriate. When using this activity, the user should ensure that all branches connected to the bus are to be placed back in service. RECN is intended to be the inverse of DSCN.

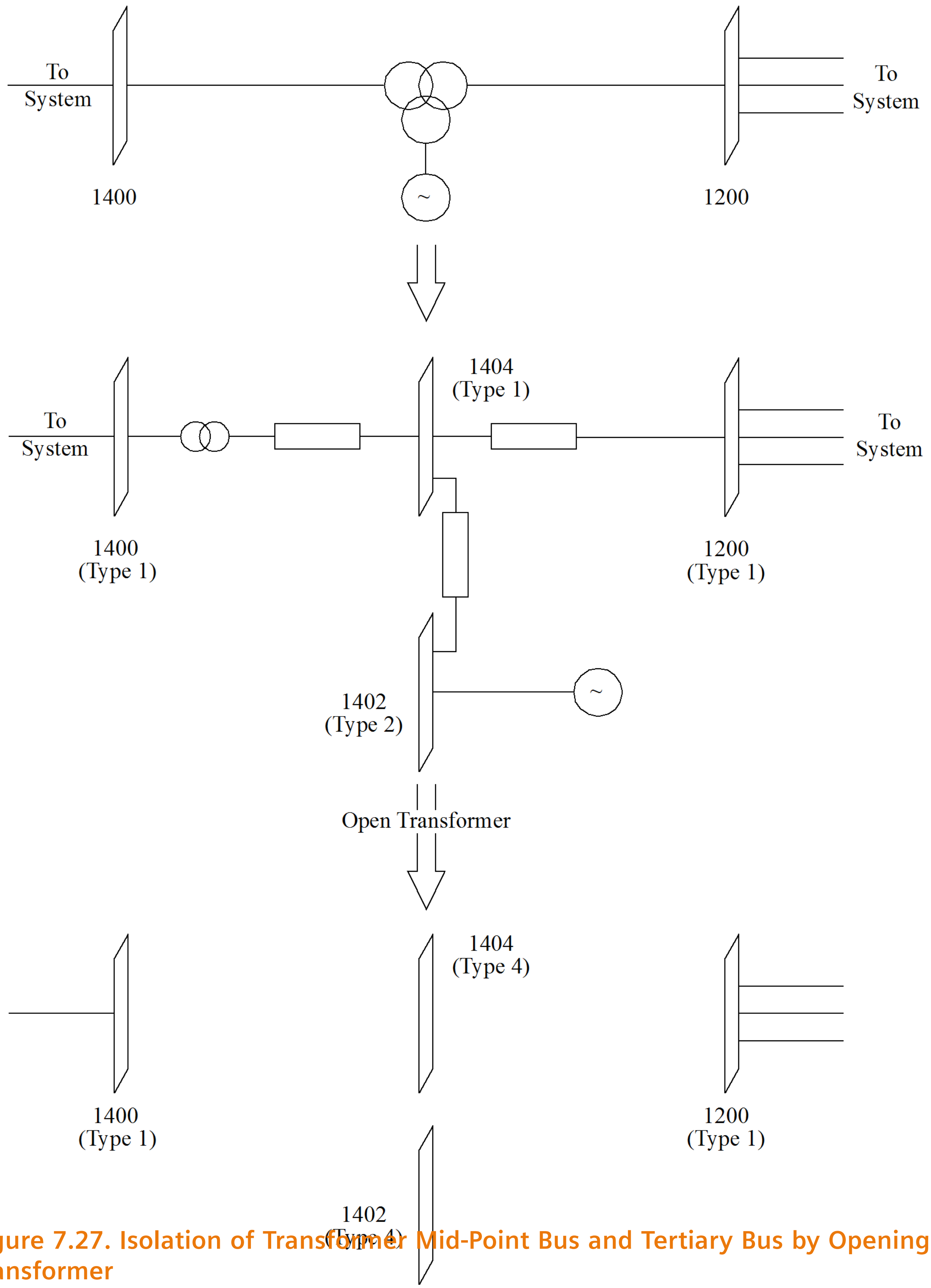


Figure 7.27. Isolation of Transformer Mid-Point Bus and Tertiary Bus by Opening of Transformer

```
ACTIVITY? case scac1
SAMPLE SYSTEM FOR PSS®E MANUAL
1100KV DC CASE

CASE scac1.sav WAS SAVED ON WED SEP 26, 1990  16:32

ACTIVITY? dscn
ENTER BUS NUMBER: 1404

TYPE CODE OF BUS  1404 [EDUM    18.0] SET TO  4
AND STATUS OF FOLLOWING CONNECTED BRANCHES SET TO 0
 CIRCUIT 1  TO BUS  1200 [STERML   230]
 CIRCUIT 1  TO BUS  1400 [             ]
 CIRCUIT 1  TO BUS  1402 [ECOND   18.0]
ENTER BUS NUMBER: 0

ACTIVITY? tree

                                 SWING BUSES

X-------BUS------X AREA    X-------BUS------X AREA    X-------BUS------X AREA
  200 HYDRO    345     1      1600 MINE     765     4


                                   ISLAND

X-------BUS------X AREA    X-------BUS------X AREA    X-------BUS------X AREA
 1402 ECOND   18.0     3

ISLAND CONTAINS    1 BUSES AND   1 PLANTS WITH TOTALS OF:

    PLOAD     QLOAD         S H U N T        PGEN      QGEN      QMAX      QMIN
      0.0       0.0       0.0     100.0       0.0     954.8     800.0    -100.0
ENTER -1 TO EXIT, 0 FOR NEXT ISLAND, 1 TO DISCONNECT THIS ISLAND: 0

NO MORE ISLANDS

ACTIVITY? chng

ENTER CHANGE CODE:
 0 = EXIT ACTIVITY                 1 = BUS DATA
 2 = GENERATOR DATA                3 = BRANCH DATA
 4 = TRANSFORMER DATA              5 = AREA INTERCHANGE DATA
 6 = TWO-TERMINAL DC LINE DATA     7 = SOLUTION PARAMETERS
 8 = CASE HEADING                  9 = SWITCHED SHUNT DATA
10 = IMPEDANCE CORRECTION TABLES  11 = MULTI-TERMINAL DC DATA
12 = ZONE DATA: 1

ENTER BUS NUMBER (0 FOR NEW CHANGE CODE, -1 TO EXIT): 1402

BUS DATA FOR BUS  1402 [ECOND   18.0] :
  CODE     PLOAD     QLOAD       S H U N T
OLD  2      0.00      0.00      0.00   100.00 CHANGE IT? 1
ENTER CODE, PLOAD, QLOAD, G, B
4
NEW  4      0.00      0.00      0.00   100.00

    AREA    VOLT    ANGLE    NAME    BASVLT LOSZON
OLD    3  1.0000     0.00 ECOND      18.0      2 CHANGE IT? 0

ENTER BUS NUMBER (0 FOR NEW CHANGE CODE, -1 TO EXIT): -1

ACTIVITY? tree

                                 SWING BUSES

X-------BUS------X AREA    X-------BUS------X AREA    X-------BUS------X AREA
  200 HYDRO    345     1      1600 MINE     765


                                   ISLAND

X-------BUS------X AREA    X-------BUS------X AREA    X-------BUS------X AREA

                          ** NONE **
```

Annotations:

Activity DSCN at bus 1404 opens transformer

Use TREE to check for inadvertent isolation

Forgot the synchronous condenser on tertiary of transformer

Could fit it here, but didn't

Instead, use CHNG to set type code of bus 1402 to 4 as required

Use TREE again for final check

OK this time

Figure 7.28. Use of DSCN and CHNG to Open Three-Winding Transformer as in Figure 7.27, "Isolation of Transformer Mid-Point Bus and Tertiary Bus by Opening of Transformer"

```
ACTIVITY? case scac1
SAMPLE SYSTEM FOR PSS®E MANUAL
1100KV DC CASE

CASE scac1.sav WAS SAVED ON WED SEP 26, 1990  16:32

ACTIVITY? dscn
ENTER BUS NUMBER: 1404
```

Activity DSCN at buses 1404 and 1402 opens transformer and takes synchronous condenser out-of-service

```
TYPE CODE OF BUS  1404 [EDUM    18.0] SET TO  4
AND STATUS OF FOLLOWING CONNECTED BRANCHES SET TO 0
 CIRCUIT 1  TO BUS  1200 [STERML   230]
 CIRCUIT 1  TO BUS  1400 [            ]
 CIRCUIT 1  TO BUS  1402 [ECOND   18.0]
ENTER BUS NUMBER: 1402

TYPE CODE OF BUS  1402 [ECOND   18.0] SET TO  4
AND STATUS OF FOLLOWING CONNECTED BRANCHES SET TO 0
ENTER BUS NUMBER: 0

ACTIVITY? tree
```

TREE to check for inadvertent isolation

```
                                 SWING BUSES

X-------BUS------X AREA    X-------BUS------X AREA    X-------BUS------X AREA
  200 HYDRO     345     1     1600 MINE      765     4

                                   ISLAND

X-------BUS------X AREA    X-------BUS------X AREA    X-------BUS------X AREA

                                 ** NONE **
```

That's OK!

```
ACTIVITY? outs
     PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS®E      WED SEP 26, 1990  16:36
SAMPLE SYSTEM FOR PSS®E MANUAL
1100KV DC CASE
```

OUTS to summarize system condition

```
OUT-OF-SERVICE BRANCHES:

X--- FROM BUS ---X AREA     X---- TO BUS ----X AREA    CKT
 1200 STERML    230     3     1404 EDUM     18.0     3    1
 1400                   1     1404 EDUM     18.0     3    1
 1402 ECOND    18.0     3     1404 EDUM     18.0     3    1
```

All three legs of the transformer are open

```
ISOLATED BUSES:

X------ BUS -----X  AREA   X------ BUS -----X  AREA   X------ BUS -----X  AREA
 1402 ECOND    18.0      3     1404 EDUM    18.0      3
```

Buses 1402, 1404 are de-energized

```
OUT-OF-SERVICE PLANTS:

X------ BUS -----X  AREA   X------ BUS -----X  AREA   X------ BUS -----X  AREA
 1402 ECOND    18.0      3
```

Synchronous condenser is off-line

```
OUT-OF-SERVICE MACHINES AT IN SERVICE PLANTS:

X------ BUS -----X  AREA   X------ BUS -----X  AREA   X------ BUS -----X  AREA

                                 ** NONE **

BLOCKED TWO-TERMINAL DC LINES:

DC# X--- RECTIFIER --X  X--- INVERTER ---X
  1  1600 MINE     765    1403 WDUM     18.0
  2  1600 MINE     765    1404 EDUM     18.0

BLOCKED MULTI-TERMINAL DC LINES:

DC# X--- CONVERTER --X X--- CONVERTER --X X--- CONVERTER --X

                                 ** NONE **

ACTIVITY? [illegible]
```

Ready to go

Figure 7.29: Use of DSCN and CHNG to Open Three-Winding Transformer as in Figure 7.27, "Isolation of Transformer Mid-Point Bus and Tertiary Bus by Opening of Transformer"

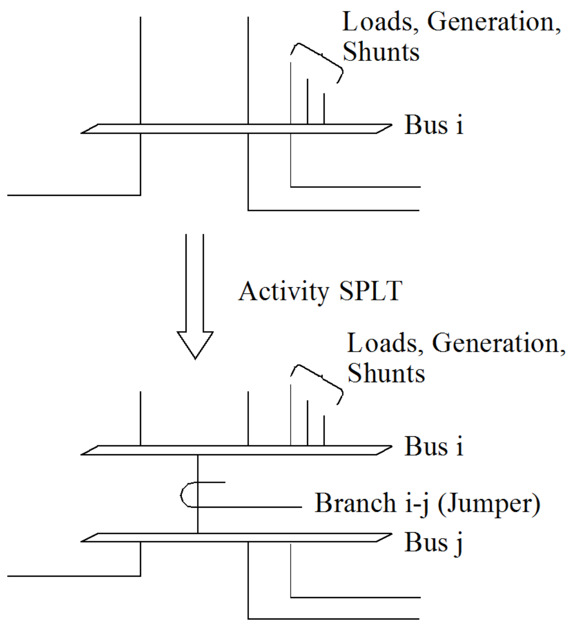


Figure 7.30. Use of SPLT to Split a Single Bus into a Pair of Buses

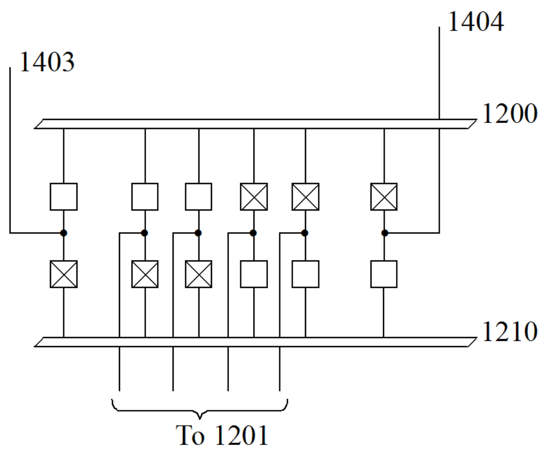
7.9.4. Activity SPLT

Activity SPLT allows a single bus to be split into a pair of new buses, as shown in Figure 7.30, "Use of SPLT to Split a Single Bus into a Pair of Buses", by any of the following means:

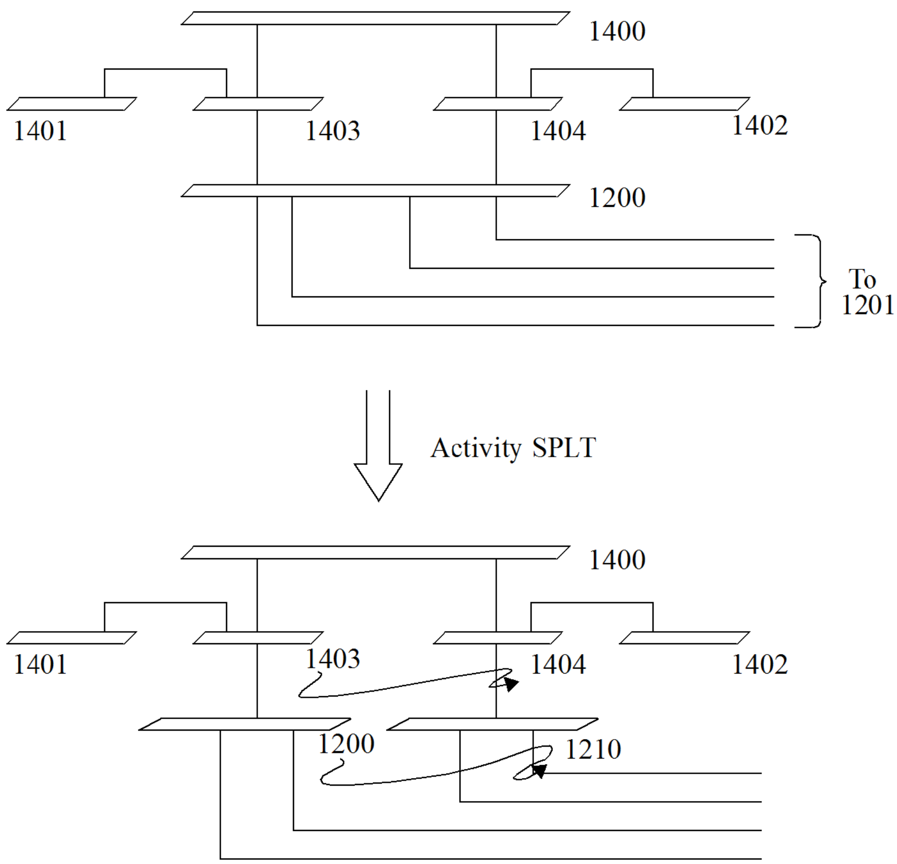
1. Create a new Type 1 bus, j.
2. Connect the new bus to the designated original bus, i, by a jumper branch equal to the zero-impedance branch threshold, THRSHZ.
3. Reroute designated branches from bus i to bus j.
4. Move generator data loads from bus i to bus j.

SPLT changes no branch service statuses, and leaves all shunt admittance at bus i unchanged. The new jumper branch, i-j, is created with in-service status.

SPLT can be used to handle bus switchings as shown in Figure 7.31, "Activity SPLT Implementation of Bus Splitting Operation", and to implement permanent sectionalizations of a bus. A permanent sectionalization is handled by splitting the bus with SPLT, or deleting the jumper branch, i-j, from the system with activity PURG (see Section 7.10.3, "Activity PURG ").



a. Splitting of Bus 1200 into Buses 1200 and 1210 by Opening Transformers and Line Circuit Breakers



b. Sectionalization of Bus 1200 and Rearrangement of Branch Connections by Activity SPLT

Figure 7.31. Activity SPLT Implementation of Bus Splitting Operation

Figure 7.31, "Activity SPLT Implementation of Bus Splitting Operation" shows the use of SPLT to implement a major bus switching operation. Figure 7.31, "Activity SPLT Implementation of Bus Splitting Operation"a shows that six circuit breakers are to be opened and will cause bus 1200 to generate a new bus that will be given the number 1210. The effect of the switching is shown in one line diagram form in Figure 7.31, "Activity SPLT Implementation of Bus Splitting Operation"b. Figure 7.33, "Use of SPLT to Modify Single Bus Into Two Buses Connected by a Jumper (Sheet 2 of 2)" shows the PSS®E dialog to run the bus switching. The step with activity CHNG is needed after execution of SPLT to open the jumper branch 1200-1210. Figure 7.33, "Use of SPLT to Modify Single Bus Into Two Buses Connected by a Jumper (Sheet 2 of 2)" shows the resulting system model being saved in file SCAC2. As a result, future work can regard buses 1200 and 1210 as halves of a sectionalized bus that can be reconnected and/or separated by the simple opening or closing of the jumper 1200-1210.

Activity SPLT does not, by itself, incorporate any intelligence on bus configuration and switch arrangement; this is provided by the user via the dialog used to select the circuits to be rerouted. In the example of Figure 7.31, "Activity SPLT Implementation of Bus Splitting Operation", the sectionalization implemented is only one of the many that could be made with the breaker-and-a-half bus arrangement. Sectionalization in different ways would require retrieval of the original unsectionalized base case, SCAC1, and re-execution of SPLT.

7.9.5. Activity JOIN

Activity JOIN allows any pair of buses to be joined together permanently. The two buses, i and j, are replaced by the single bus, i, as shown in Figure 7.34, "Merging Two Buses with Activity JOIN".

When two buses, i and j, are specified, activity JOIN will do the following:

1. Change the type code of bus i to 2 or 3 if the type code of bus j is 2 or 3.

2. Add the load and shunt admittance of bus j onto the corresponding quantities of bus i.

3. Move all generating units at bus j onto bus i, giving them unit numbers in sequence above the unit numbers already in use at bus i.

4. Delete all branches running between buses i and j from the working case.

5. Reroute all other branches running to bus j to run, instead, to bus i.

6. Delete bus j from the working case.

Activity JOIN is useful in the following situations:

- The sectionalization of a bus is no longer needed and its sections are to be connected together permanently.

- The use of a low-impedance jumper branch to join two buses is unsatisfactory because of computer precision limitations.

The sections of a bus are to be redefined by a subsequent execution of SPLT after the original sections have been merged with JOIN.

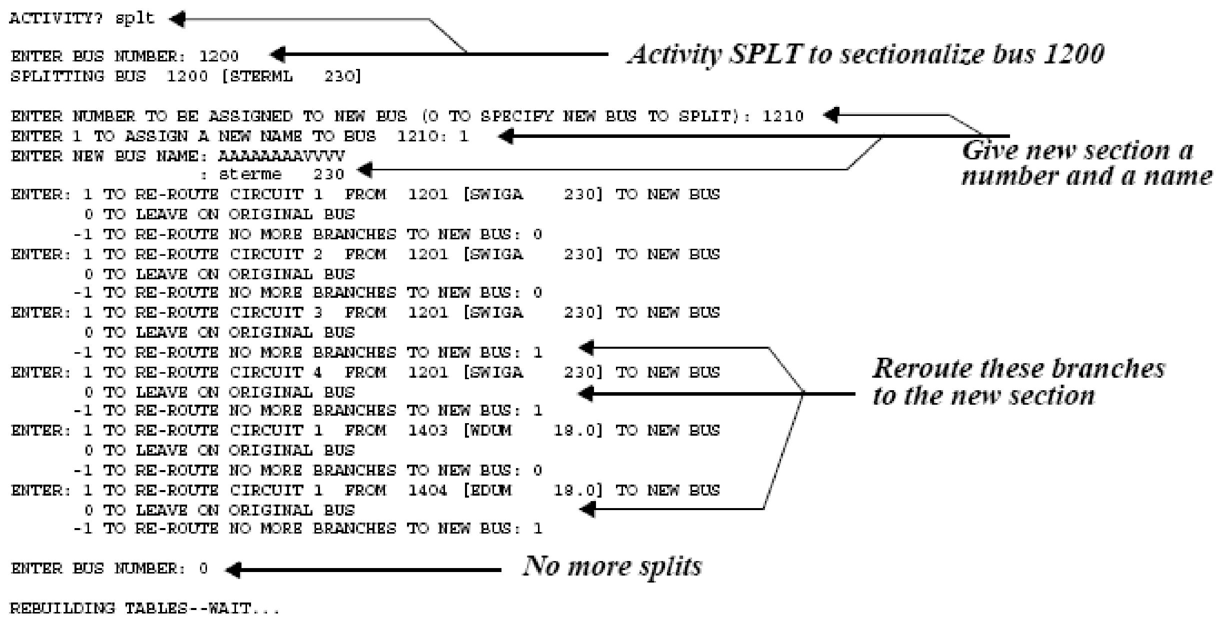


Figure 7.32. Use of SPLT to Modify Single Bus Into Two Buses Connected by a Jumper (Sheet 1 of 2)

```
ACTIVITY? exam

ENTER OUTPUT DEVICE CODE:
 0 FOR NO OUTPUT      1 FOR CRT TERMINAL
 2 FOR A FILE         3 FOR QMS_PS800
 4 FOR GENICOM        5 FOR HARD COPY TERMINAL
 6 FOR ALTERNATE SPOOL DEVICE: 1
ENTER UP TO 20 BUS NUMBERS
1210

     PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS/E      WED SEP 26, 1990  16:41
SAMPLE SYSTEM FOR PSS/E MANUAL
1100KV DC CASE

DATA FOR BUS  1210 [STERME   230] RESIDING IN AREA   3 AND ZONE   2:

CODE  PLOAD   QLOAD  G-SHUNT B-SHUNT VOLTAGE   ANGLE
  1     0.0     0.0     0.0     0.0 1.00000    0.00

X--------TO-------X CKT   LINE R   LINE X CHARGING ST/MET RATE-A RATE-B RATE-C
 1200 STERML   230  1   0.00000 0.00010  0.00000  1  T     0.0    0.0    0.0 *
 1201 SWIGA    230  3   0.00015 0.00200  0.00450  1  F   750.0  800.0  850.0
 1201 SWIGA    230  4   0.00015 0.00200  0.00450  1  F   750.0  800.0  850.0
 1404 EDUM    18.0  1   0.00000 -0.00050 0.00000  1  F  1780.0 1900.0 2000.0

  TO CKT TP  RATIO  ANGLE RG CONT   RMAX    RMIN    VMAX    VMIN   TSTP TAB    NOMINAL R,X
 1404 1   F 1.00000   0.00 1       1.10000 0.90000 1.03000 1.02000 0.00625
ENTER UP TO 20 BUS NUMBERS
0
 ACTIVITY? chng

ENTER CHANGE CODE:
 0 - EXIT ACTIVITY                  1 - BUS DATA
 2 - GENERATOR DATA                 3 - BRANCH DATA
 4 - TRANSFORMER DATA               5 - AREA INTERCHANGE DATA
 6 - TWO-TERMINAL DC LINE DATA      7 - SOLUTION PARAMETERS
 8 - CASE HEADING                   9 - SWITCHED SHUNT DATA
10 - IMPEDANCE CORRECTION TABLES   11 - MULTI-TERMINAL DC DATA
12 - ZONE DATA: 3

ENTER FROM BUS, TO BUS, CIRCUIT IDENTIFIER
 (FROM BUS = 0 FOR NEW CHANGE CODE, -1 TO EXIT): 1200 1210

THIS BRANCH IS CURRENTLY TREATED AS A ZERO IMPEDANCE LINE

BRANCH DATA FOR CIRCUIT 1  FROM  1200 [STERML   230] TO  1210 [STERME   230]:
 STATUS     LINE R     LINE X   CHARGING  RATE-A  RATE-B  RATE-C
OLD   1   0.00000   0.00010   0.00000     0.0     0.0     0.0 CHANGE IT? 1
ENTER STATUS, R, X, CHARGING, RATE-A, RATE-B, RATE-C, # OF CIRCUITS
0
NEW   0   0.00000   0.00010   0.00000     0.0     0.0     0.0

LINE SHUNTS: BUS  1200 [STERML   230]  BUS  1210 [STERME   230]
OLD                 0.00000   0.00000          0.00000   0.00000 CHANGE IT?

METERED END IS BUS  1200 [STERML   230]. ENTER 1 TO REVERSE:

ENTER FROM BUS, TO BUS, CIRCUIT IDENTIFIER
 (FROM BUS = 0 FOR NEW CHANGE CODE, -1 TO EXIT): -1

ACTIVITY? save scac2

CASE SAVED IN FILE scac2.sav ON WED SEP 26, 1990  16:42
```

Check data on new bus with EXAM

Note new jumper branch representing a closed bus tie breaker

Treated as zero-impedance line

Use CHNG to open the bus tie to reflect actual breaker positions for case at hand

Open it

Save modified case for future studies

Figure 7.33. Use of SPLT to Modify Single Bus Into Two Buses Connected by a Jumper (Sheet 2 of 2)

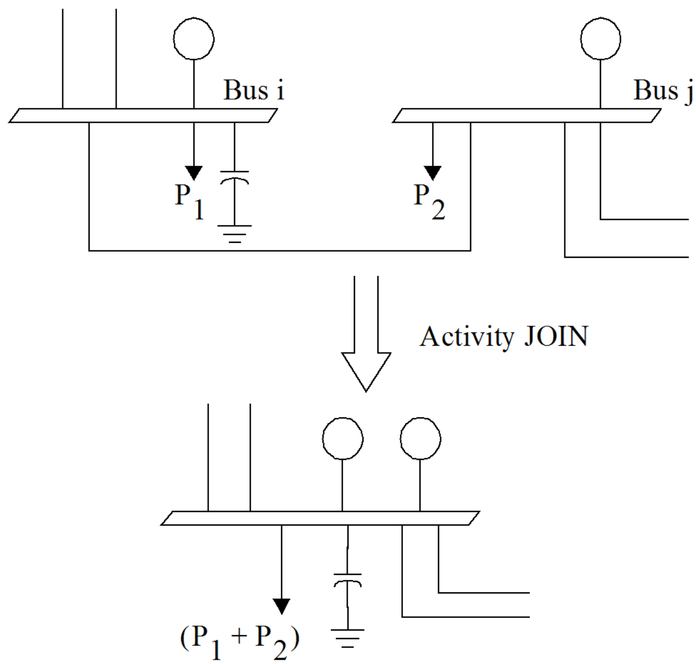


Figure 7.34. Merging Two Buses with Activity JOIN

7.9.6. Notes on SPLT and JOIN

The following information about SPLT and JOIN is worth noting:

1. The dialog of JOIN is much simpler and quicker than that of SPLT.

2. After completion of the dialog, the execution of SPLT is substantially quicker than that of JOIN when dealing with large systems.

3. SPLT requires the user to locate and enter a new, unused, bus number or name each time a bus is sectionalized.

Bus switching may be handled either by specifying the sections of the bus, with different numbers and names, in the original power flow data, or by the use of SPLT and JOIN. The former approach is practical when it is known in advance that a bus will always be split in the same way, but is not practical when a large number of combinations of branch-bus connections is possible, as in the example shown in Figure 7.31, "Activity SPLT Implementation of Bus Splitting Operation".

A more practical approach for major substations, where it is known that sectionalization is likely but the details of sectionalization are not known in advance, is as follows:

1. Establish the bus in original power flow data as two sections with distinct numbers and names, and with a jumper of impedance j0.0001, between them. This reserves two names and numbers for the substation and avoids difficulties in searching for an available name or number later on.

2. Save the power flow case in saved case form with the two distinct bus sections present, with the jumper in service, and without particular concern for the specific sectionalization arrangement.

3. Establish the particular bus arrangement needed for each power flow case, or group of cases, by retrieving the base case as recorded in Step 2 and using JOIN and SPLT to rearrange switching as required.

7.9.7. Activity LTAP

Activity LTAP allows any nontransformer ac branch to be tapped at a designated location along the line as shown in Figure 7.35, "Creation of New Bus by Tapping Online using Activity LTAP". Activity LTAP:

1. Creates a new bus, k, of Type 1.

2. Creates lines from bus i to bus k and from bus k to bus j. Resistance, reactance, and charging are apportioned according to the percentage distance specified.

3. Moves line shunts from original line to the appropriate ends on new lines.

4. Removes the original line i to j from the working case.

Activity LTAP works for all three sequences. A list of new mutual coupling values is automatically printed. This activity should be used with caution on lines where the line capacitance is specified as line shunts. For these lines, the capacitance will all be kept as line shunts and not distributed across each section.

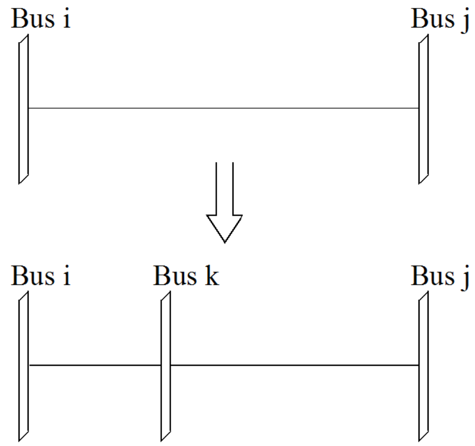


Figure 7.35. Creation of New Bus by Tapping Online using Activity LTAP

7.10. System Modeling Updating

7.10.1. Partial Model Replacement

Power system models are never static, especially in the planning process where the updating of construction proposals, load data, and system representations are the object of the power flow work. Figure 7.36, "Replacement Of Old Area 3 Model With New Data" shows a very common process in power system modeling. An established power flow case, CASE1, contains a system model in which one area, area 3, is represented by obsolete data. New data on area 3 has been obtained through a power pool but, because of an inevitable numbering problem, uses bus numbers 520-580 where the old area 3 data used numbers 900-960. A quick check reveals that some bus numbers in the range 520-580 may already be used in areas 7 and 8. The adoption of the updated data requires the steps shown in Figure 7.36, "Replacement Of Old Area 3 Model With New Data":

1. Read the new area 3 model into the working file with activity READ.

2. Use activity BSNM to reassign bus numbers of this model to the range 900-960.

3. Use activity RWMA to make a new raw data file, B, for the new area 3 model. Note that this new data file will include only buses in area 3, and will not include tie branches to areas 7 and 8.

4. Transfer the old power flow case from its saved case file, CASE1, into the working case.

5. Delete the old model of area 3 from the working file with activity EXTR.

6. Read the new area 3 model into the working case from file B with activity READ. Note that the change code in the first data record of file B must have been changed to 1 to cause the area 3 data to be appended to the areas 7 and 8 models already in the working case.

7. Use activity Reading Power Flow Data Additions from the Terminal to enter data on tie branches between area 3 and areas 7 and 8.

The use of activity BSNM in this example avoids the possible conflict of bus numbers between the old (area 7, 8) data and new (area 3) data, but *did not* assure that the number of each bus in area 3 is the same in the old and new system model setups. In fact, the use of BSNM did not even assure that the old and new area 3 data covered the same number of buses. It is quite possible that the new area 3 data represents a new construction proposal that does not include some of the buses and tie-lines represented by the old area 3 model. The final step of Figure 7.36, "Replacement Of Old Area 3 Model With New Data", in consequence, usually involves close manual checking of data to ensure that tie branches are placed correctly between the old and new sections of the full system model.

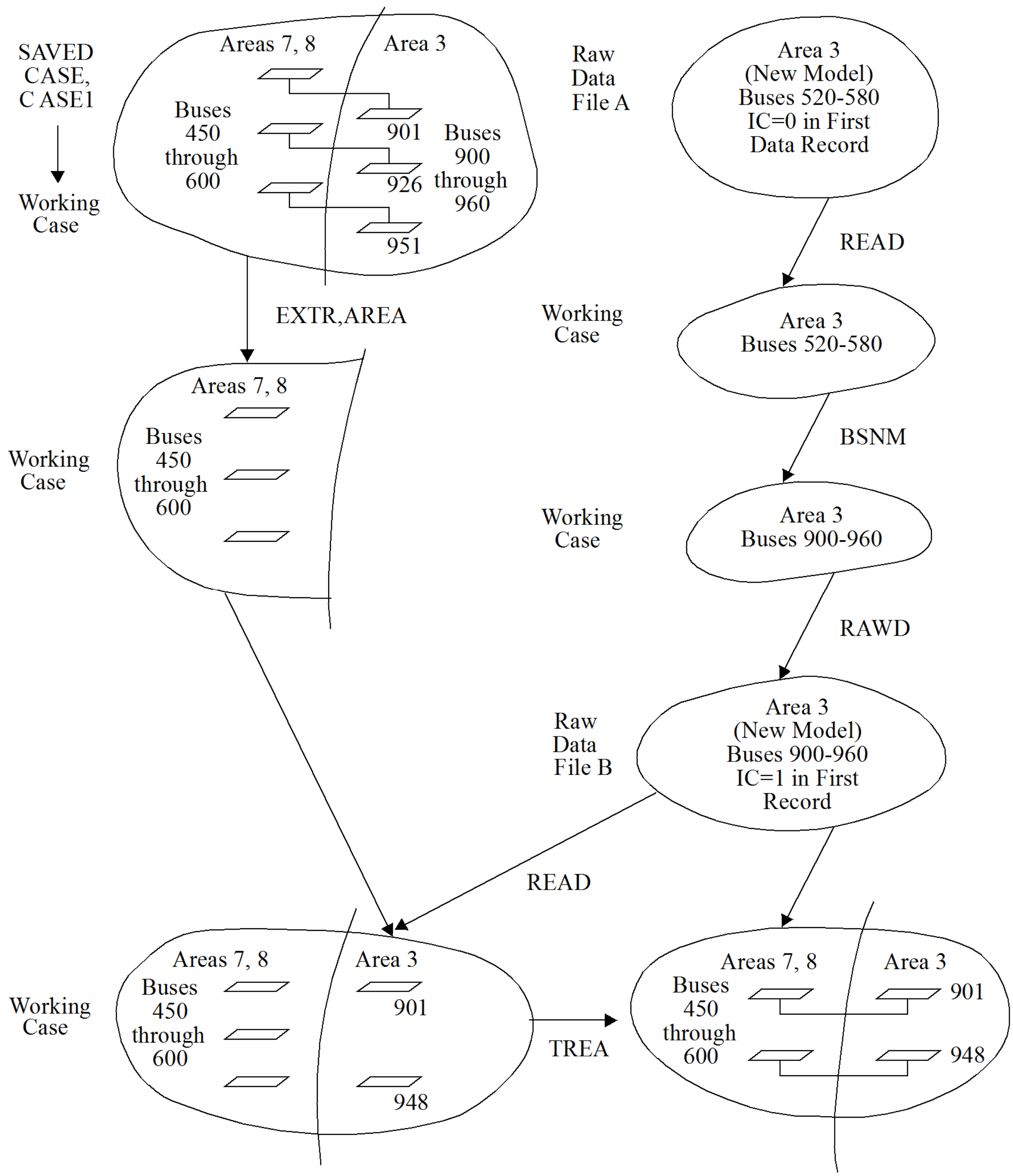


Figure 7.36. Replacement Of Old Area 3 Model With New Data

7.10.2. Activity EXTR

Activity EXTR is used to truncate the system model in the working case by deleting designated buses, and all branches connected to them, from the working case. EXTR includes options to delete data table entries for generators at Type 1 buses, and identify boundary buses for equivalent construction purposes. (This function is described in detail in Chapter 8.)

The generator deletion option is useful in long-range planning work, when a proposed generating plant is to be moved (i.e., relocated) from one bus to another. Generation at a single bus can be deleted with no other effect on the system by changing the bus type code to 1 and executing EXTR with no buses designated for deletion.

The subsystem to be deleted by EXTR may be specified by the area, zone, owner, voltage level, and bus number options described in Section 6.3.1, "Report Selection and Routing ". The part of the system that is not deleted may be used for the following:

- The basis for equivalent construction (see Chapter 8).
- The base for construction of a new system model by adding new equipment with activity READ.
- The source of a new power flow raw data file to be produced by activity RWMA as described in Section 7.10.4, "Activities RAWD and RWCM".

Figure 7.37, "Use of EXTR to Delete Buses 1 and 2" shows the console dialog from activity EXTR. In this example, buses 1 and 2 are discarded from the working case.

```
ACTIVITY? case scac1  <------------------------------------ Specify subsystem by areas
SAMPLE SYSTEM FOR PSS®E MANUAL
1100KV DC CASE

CASE scac1.sav WAS SAVED ON WED SEP 26, 1990 16:32

ACTIVITY? extra
WARNING: EXTR PURGES DATA FROM THE WORKING CASE
DO YOU WANT TO CONTINUE? yes
ENTER 1 TO ELIMINATE GENERATOR ENTRIES FOR OUT-OF-SERVICE PLANTS: 0  <-- Keep all generators
ENTER 1 TO CHANGE CODES OF BOUNDARY BUSES: 0  <--------------- This option is used only in
                                                               equivalent construction
USER SPECIFIES SUBSYSTEM TO BE DELETED
ENTER UP TO 20 BUS NUMBERS
1 2  <------------------------------------ Delete buses 1, 2.
ENTER UP TO 20 BUS NUMBERS                 Keep all others.
0

REBUILDING TABLES--WAIT...
```

Figure 7.37. Use of EXTR to Delete Buses 1 and 2

7.10.3. Activity PURG

Activity PURG deletes ac branches, switched shunts, machines, plants and/or dc lines from the working files. Deletion *is not* equivalent to removing equipment from service; after deletion by PURG the equipment can only be returned to the case by reconstructing it (use READ, Reading Power Flow Data Additions from the Terminal, etc.).

There are two modes in which activity PURG can be run. In the first mode, when called with the standard activity suffixes or with no suffix at all, the activity removes all inactive out-of-service equipment requested in the specified subsystem. If run with the command PURG,SI, the equipment will be removed regardless of its status.

7.10.4. Activities RAWD and RWCM

Activities RAWD and RWCM are the means by which power flow data established within PSS®E is exported to other computer programs. Each activity produces a power flow raw data file describing a designated section of the power flow setup in the working case. The subsystem is specified in accordance with the options of Section 6.6.1 Report Selection and Routing. No data is changed; if the working case is solved the resulting raw data file will represent the solved case to the extent that it is able. The formats of the raw data files produced by these activities are as follows:

RAWD

PSS®E format power flow raw data file.

RWCM

Power flow solved case data file in IEEE common format.

RAWD allows isolated buses and out-of-service branches to be included in, or excluded from, the raw data file as it is constructed. Such system elements would be included when the raw data file is to be transmitted as a complete system model to an external organization. Isolated and out-of-service elements would be excluded when the raw data file is to be used in the equivalent construction process.

To accommodate the needs of equivalent construction, RAWD, invites the user to specify the level of completeness of the raw data file to be produced. The options are:

1. Include all categories (bus, generator, branch, transformer, etc.) of data for all elements within the specified subsystem, but exclude data on tie branches running to buses outside the designated subsystem.

2. Build raw data files in which all sections of the file except the branch and transformer sections are null. Include only data on branches running from a bus in the specified subsystem to a bus outside it.

3. Build a raw data file including data specified using options 1 and 2 above.

When not used in equivalent construction, RAWD and RWCM are most often used to construct power flow tapes describing the complete working case for export to other computers. Figure 7.38, "Use of PSS®E Activity RWCM" shows the dialog for production of an IEEE common format power flow data file.

```
ACTIVITY? case scac1
SAMPLE SYSTEM FOR PSS®E MANUAL
1100KV DC CASE

CASE scac1.sav WAS SAVED ON WED SEP 26, 1990 16:32

ACTIVITY? rwcm all

ENTER OUTPUT DEVICE CODE:
0 FOR NO OUTPUT      1 FOR CRT TERMINAL
2 FOR A FILE         3 FOR QMS_PS800
4 FOR GENICOM        5 FOR HARD COPY TERMINAL
6 FOR ALTERNATE SPOOL DEVICE: 2
ENTER OUTPUT FILE NAME: export-ieee

ACTIVITY? stop
$prf export-ieee.dat
export-ieee.dat queued to printer p
```

Pick up the case to be exported

Write an IEEE Common Format data file

To this file

Finished with PSS®E

Spool the file to take a look

Figure 7.38. Use of PSS®E Activity RWCM

Chapter 8
Equivalents

8.1. Activity BGEN

There are times when a user is doing studies so localized that outside world effects are negligible and does not want to be burdened by the additional computational penalty added by an equivalent. Activity BGEN allows creation of loads and/or generators at all buses where there is a mismatch greater than 0.5 MVA. It will usually be run after an activity such as EXTR in which the external system has been deleted from the working files.

```
$  psslf4 -w off

                POWER TECHNOLOGIES INCORPORATED

         12000 BUS POWER SYSTEM SIMULATOR--PSS®E-22.0

 INITIATED AT LOAD FLOW ENTRY POINT ON THU MAR 24, 1994  10:57

 ACTIVITY? read
 ENTER INPUT FILE NAME (0 TO EXIT, 1 FOR TERMINAL): FILE-B.DAT

 ENTER IC, SBASE

 ENTER TWO LINE HEADING

 ENTER BUS DATA

 ENTER GENERATOR DATA

 WARNING: NO SWING BUS IN CASE

 ENTER BRANCH DATA

 ENTER TRANSFORMER ADJUSTMENT DATA

 ENTER AREA INTERCHANGE DATA

 ENTER TWO-TERMINAL DC LINE DATA

 ENTER SWITCHED SHUNT DATA

 ENTER TRANSFORMER IMPEDANCE CORRECTION DATA

 ENTER MULTI-TERMINAL DC LINE DATA

 ENTER MULTI-SECTION LINE DATA

 ENTER ZONE NAME DATA

 ENTER AREA TRANSACTION DATA

 BUILDING TABLES--WAIT...

 ACTIVITY? read,area
 ENTER INPUT FILE NAME (0 TO EXIT, 1 FOR TERMINAL): INDAT.DAT
 ENTER UP TO 20 AREA NUMBERS
1,2,4
 ENTER UP TO 20 AREA NUMBERS
0
 ENTER 1 TO APPEND DATA TO THE WORKING CASE: 1
 ENTER 1 TO CHANGE CODES OF BOUNDARY BUSES: 0

 ENTER: 1 FOR ALL DATA WITHIN SPECIFIED SUBSYSTEM
        2 FOR TIES FROM SPECIFIED SUBSYSTEM
        3 FOR ALL DATA PLUS TIES: 3

 ENTER IC, SBASE

 ENTER TWO LINE HEADING

 ENTER BUS DATA

 ENTER GENERATOR DATA

 ENTER BRANCH DATA

 ENTER TRANSFORMER ADJUSTMENT DATA

 ENTER AREA INTERCHANGE DATA

 ENTER TWO-TERMINAL DC LINE DATA

 ENTER SWITCHED SHUNT DATA

 ENTER TRANSFORMER IMPEDANCE CORRECTION DATA

 ENTER MULTI-TERMINAL DC LINE DATA

 ENTER MULTI-SECTION LINE DATA
```

Initiate PSS®E at the power flow entry point, PSSLF4

Initialize working case and read in equivalent of area 3 with activity

Data is contained in the file named FILE-B

Activity READ,AREA to pick up data for areas 1,2, and 4 from data file of its source system

Add areas onto representation of area 3 in working case

Only areas 1, 2, and 4 are to be picked up from file INDAT

Figure 8.1. Use of Area 3 Data Together with Detailed Representation of Areas 1, 2, and 4 to Make Reduced Size Representation of Complete Sample System (Sheet 1 of 4)

```
ENTER ZONE NAME DATA

ENTER AREA TRANSACTION DATA

BUILDING TABLES--WAIT...

ACTIVITY? solv

ITER DELTAV/TOL  BUS    REAL(DELTAV)    IMAG(DELTAV)
   1      0.521  1201     0.5121E-04     -0.9584E-05

REACHED TOLERANCE IN   1 ITERATIONS

LARGEST MISMATCH:     0.09 MW    -1.03 MVAR      1.03 MVA-BUS  1404 [EDUM     18.0]
SYSTEM TOTAL ABSOLUTE MISMATCH:                  5.60 MVA

ACTIVITY? fnsl

ORDERING NETWORK
DIAGONALS =     15  OFF-DIAGONALS =     21  MAX SIZE =     34

ENTER ITERATION NUMBER FOR VAR LIMITS
 0 FOR IMMEDIATELY, -1 TO IGNORE COMPLETELY:

ITER    DELTAP   BUS       DELTAQ   BUS      DELTA/V/    BUS    DELTAANG    BUS
  0     0.0014( 1402)     0.0116( 1402)
                                              0.00150(  800)    0.00051( 1300)
  1     0.0000( 1100)     0.0665(  800)
                                              0.00143(  800)    0.00038( 1300)
  2     0.0000( 1100)     0.0228( 1401)
                                              0.00007( 1401)    0.00000( 1300)
  3     0.0000(  500)     0.0010( 1402)
                                              0.00000( 1402)    0.00000( 1402)
  4     0.0000( 1401)     0.0001( 1401)


REACHED TOLERANCE IN   4 ITERATIONS

LARGEST MISMATCH:     0.00 MW     0.01 MVAR      0.01 MVA-BUS  1404 [EDUM     18.0]
SYSTEM TOTAL ABSOLUTE MISMATCH:                  0.06 MVA

ACTIVITY? pout,all

ENTER OUTPUT DEVICE CODE:
 0 FOR NO OUTPUT         1 FOR CRT TERMINAL
 2 FOR A FILE            3 FOR QMS PS2000
 4 FOR QMS_PS800         5 FOR HARD COPY TERMINAL
 6 FOR ALTERNATE SPOOL DEVICE: 1

     PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS®E      THU MAR 24, 1994  10:59
SAMPLE SYSTEM FOR PSS®E MANUAL                                           RATING
1100KV DC CASE                                                            SET A

BUS    100 NUCLEAR  345 AREA CKT     MW      MVAR     MVA  %I 1.0400PU  -2.06  100
 GENERATION               1       2000.0   11.1R 2000.0  91 358.80KV
 TO    200 HYDRO    345   1  1    -168.7    -3.5   168.8  19
 TO    200 HYDRO    345   1  2    -168.7    -3.5   168.8  19
 TO    300 WEST     345   1  1     411.8   -26.6   412.7  47
 TO    300 WEST     345   1  2     411.8   -26.6   412.7  47
 TO   1550 MIDPNTL  345   4  1     756.9    35.7   757.8  86
 TO   1550 MIDPNTL  345   4  2     756.9    35.7   757.8  86

BUS    200 HYDRO    345 AREA CKT     MW      MVAR     MVA  %I 1.0400PU   0.00  200
 GENERATION               1       1237.1 -124.9R 1243.3  71 358.80KV
 TO    100 NUCLEAR  345   1  1     169.4   -40.8   174.2  20
 TO    100 NUCLEAR  345   1  2     169.4   -40.8   174.2  20
 TO    400 EAST     345   1  1     449.1   -21.7   449.7  51
 TO    400 EAST     345   1  2     449.1   -21.7   449.7  51

     PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS®E      THU MAR 24, 1994  10:59
SAMPLE SYSTEM FOR PSS®E MANUAL                                           RATING
1100KV DC CASE                                                            SET A

BUS    300 WEST     345 AREA CKT     MW      MVAR     MVA  %I 0.9998PU -22.65  300
                          1                                  344.93KV
 TO    100 NUCLEAR  345   1  1    -395.6   -20.4   396.2  47
 TO    100 NUCLEAR  345   1  2    -395.6   -20.4   396.2  47
 TO    400 EAST     345   1  1     -16.4   -40.7    43.9   5
 TO    500 WESTLV   230   2  1     403.8    40.8   405.9  81 1.0000LK
 TO    500 WESTLV   230   2  2     403.8    40.8   405.9  81 1.0000LK
```

Working case now contains detailed representation of areas 1, 2, and 4 attached to area 3

Solve power flow case with activity SOLV and later FNSL

Activity POUT, ALL to print full output for this new composite power flow case

Figure 8.2. Use of Area 3 Data Together with Detailed Representation of Areas 1, 2, and 4 to Make Reduced Size Representation of Complete Sample System (Sheet 2 of 4)

```
BUS    400 EAST      345 AREA CKT     MW      MVAR     MVA   %I 1.0042PU -22.46   400
                           1                                    346.44KV
 TO    200 HYDRO     345    1   1   -429.9      1.3    429.9   50
 TO    200 HYDRO     345    1   2   -429.9      1.3    429.9   50
 TO    300 WEST      345    1   1     16.4     -5.8     17.4    2
 TO    600 EASTLV    230    2   1    421.7      1.6    421.7   56 1.0000LK
 TO    600 EASTLV    230    2   2    421.7      1.6    421.7   56 1.0000LK

     PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS®E      THU MAR 24, 1994  10:59
SAMPLE SYSTEM FOR PSS®E MANUAL                                         RATING
1100KV DC CASE                                                          SET A

BUS    500 WESTLV    230 AREA CKT     MW      MVAR     MVA   %I 0.9955PU -26.14   500
                           2                                    228.97KV
 TO LOAD-PQ                          750.0      0.0    750.0
 TO    300 WEST      345    1   1   -403.8    -16.1    404.2   81 1.0000UN
 TO    300 WEST      345    1   2   -403.8    -16.1    404.2   81 1.0000UN
 TO    700 SWURB     230    2   1     28.8     16.1     33.0    7
 TO    700 SWURB     230    2   2     28.8     16.1     33.0    7

BUS    600 EASTLV    230 AREA CKT     MW      MVAR     MVA   %I 1.0049PU -24.86   600
                           2                                    231.13KV
 TO LOAD-PQ                          500.0      0.0    500.0
 TO    400 EAST      345    1   1   -421.7     16.0    422.0   56 1.0000UN
 TO    400 EAST      345    1   2   -421.7     16.0    422.0   56 1.0000UN
 TO    700 SWURB     230    2   1    136.8     53.4    146.8   29
 TO    700 SWURB     230    2   2    136.8     53.4    146.8   29
 TO    800 SETOUN    230    2   1     34.9    -69.4     77.7   15
 TO    800 SETOUN    230    2   2     34.9    -69.4     77.7   15

     PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS®E      THU MAR 24, 1994  10:59
SAMPLE SYSTEM FOR PSS®E MANUAL                                         RATING
1100KV DC CASE                                                          SET A

BUS    700 SWURB     230 AREA CKT     MW      MVAR     MVA   %I 0.9911PU -26.48   700
                           2                                    227.95KV
 TO LOAD-PQ                         1250.0      0.0   1250.0
 TO    500 WESTLV    230    2   1    -28.8    -20.3     35.3    7
 TO    500 WESTLV    230    2   2    -28.8    -20.3     35.3    7
 TO    600 EASTLV    230    2   1   -136.4    -53.3    146.4   30
 TO    600 EASTLV    230    2   2   -136.4    -53.3    146.4   30
 TO   1201 SWIGA     230    3   1   -459.8     73.6    465.6   94
 TO   1201 SWIGA     230    3   2   -459.8     73.6    465.6   94

BUS    800 SETOUN    230 AREA CKT     MW      MVAR     MVA   %I 1.0185PU -25.34   800
                           2                                    234.26KV
 TO LOAD-PQ                          500.0      0.0    500.0
 TO    600 EASTLV    230    2   1    -34.8     66.0     74.6   15
 TO    600 EASTLV    230    2   2    -34.8     66.0     74.6   15
 TO   1100 CATNIP    230    2   1   -248.1   -109.9    271.4   53
 TO   1100 CATNIP    230    2   2   -248.1   -109.9    271.4   53
 TO   1300 SERGA     230    3   1     65.9     87.8    109.8   22

     PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS®E      THU MAR 24, 1994  10:59
SAMPLE SYSTEM FOR PSS®E MANUAL                                         RATING
1100KV DC CASE                                                          SET A

BUS   1100 CATNIP    230 AREA CKT     MW      MVAR     MVA   %I 1.0611PU -21.28  1100
 GENERATION                2         500.0    250.0H   559.0  112 244.04KV
 TO    800 SETOUN    230    2   1    250.0    125.0    279.5   53
 TO    800 SETOUN    230    2   2    250.0    125.0    279.5   53

BUS   1201 SWIGA     230 AREA CKT     MW      MVAR     MVA   %I 0.9942PU -14.85  1201
                           3                                    228.66KV
 TO LOAD-PQ                         1000.0      0.0   1000.0
 TO SHUNT                              0.0   -199.3    199.3
 TO    700 SWURB     230    2   1    467.5     11.8    467.7   94
 TO    700 SWURB     230    2   2    467.5     11.8    467.7   94
 TO   1300 SERGA     230    3   1    475.3     43.7    477.3   96
 TO   1300 SERGA     230    3   2    475.3     43.7    477.3   96
 TO   1403 WDUM     18.0    3  99 -1442.9     44.1   1443.5
 TO   1404 EDUM     18.0    3  99 -1442.9     44.1   1443.5
```

Figure 8.3. Use of Area 3 Data Together with Detailed Representation of Areas 1, 2, and 4 to Make Reduced Size Representation of Complete Sample System (Sheet 3 of 4)

```
     PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS®E      THU MAR 24, 1994  10:59
SAMPLE SYSTEM FOR PSS®E MANUAL                                           RATING
1100KV DC CASE                                                            SET A

BUS  1300 SERGA     230 AREA CKT    MW     MVAR     MVA  %I 0.9779PU -26.77 1300
                          3                                 224.91KV
 TO LOAD-PQ                       1000.0     0.0  1000.0
 TO   800 SETOUN    230   2  1     -65.5   -91.6   112.6  23
 TO  1201 SWIGA     230   3  1    -467.3    45.8   469.5  96
 TO  1201 SWIGA     230   3  2    -467.3    45.8   469.5  96

BUS  1401 WCOND    18.0 AREA CKT    MW     MVAR     MVA  %I 1.0259PU  -7.22 1401
 GENERATION               3          0.0   653.5R  653.5  82 18.466KV
 TO SHUNT                            0.0  -105.2   105.2
 TO  1403 WDUM     18.0   3  1       0.0   758.8   758.8  74

BUS  1402 ECOND    18.0 AREA CKT    MW     MVAR     MVA  %I 1.0259PU  -7.22 1402
 GENERATION               3          0.0   653.5R  653.5  82 18.466KV
 TO SHUNT                            0.0  -105.2   105.2
 TO  1404 EDUM     18.0   3  1       0.0   758.8   758.8  74

     PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS®E      THU MAR 24, 1994  10:59
SAMPLE SYSTEM FOR PSS®E MANUAL                                           RATING
1100KV DC CASE                                                            SET A

BUS  1403 WDUM     18.0 AREA CKT    MW     MVAR     MVA  %I 1.0000PU  -7.22 1403
                          3                                 18.000KV
 TO SHUNT                            0.0     0.0     0.0
 TO  1600 MINE      INVERTER# 1 -1444.3   590.9  1560.6     1.0000RG  18.17RG
 TO  1201 SWIGA     230   3  99   1444.3   148.8  1452.0
 TO  1401 WCOND    18.0   3  1       0.0  -739.6   739.6  74
 TO  1404 EDUM     18.0   3  99      0.0     0.0     0.0

BUS  1404 EDUM     18.0 AREA CKT    MW     MVAR     MVA  %I 1.0000PU  -7.22 1404
                          3                                 18.000KV
 TO SHUNT                            0.0     0.0     0.0
 TO  1600 MINE      INVERTER# 2 -1444.3   590.9  1560.6     1.0000RG  18.17RG
 TO  1201 SWIGA     230   3  99   1444.3   148.8  1452.0
 TO  1402 ECOND    18.0   3  1       0.0  -739.6   739.6  74
 TO  1403 WDUM     18.0   3  99      0.0     0.0     0.0

     PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS®E      THU MAR 24, 1994  10:59
SAMPLE SYSTEM FOR PSS®E MANUAL                                           RATING
1100KV DC CASE                                                            SET A

BUS  1550 MIDPNTL   345 AREA CKT    MW     MVAR     MVA  %I 1.0285PU  -6.65 1550
                          4                                 354.85KV
 TO LOAD-PQ                       1500.0     0.0  1500.0
 TO   100 NUCLEAR   345   1  1    -750.0     0.0   750.0  86
 TO   100 NUCLEAR   345   1  2    -750.0     0.0   750.0  86

BUS  1600 MINE      765 AREA CKT    MW     MVAR     MVA  %I 1.0400PU   0.00 1600
 GENERATION               4       3000.0   835.4R 3114.2  97 795.60KV
 TO  1403 WDUM      RCTIFIER# 1   1500.0   417.7  1557.1     1.0313RG   6.76RG
 TO  1404 EDUM      RCTIFIER# 2   1500.0   417.7  1557.1     1.0313RG   6.76RG
```

Figure 8.4. Use of Area 3 Data Together with Detailed Representation of Areas 1, 2, and 4 to Make Reduced Size Representation of Complete Sample System (Sheet 4 of 4)

```
$ psslf4 -w off
```

Initiate PSS®E at the power flow entry point PSSLF4

```
                POWER TECHNOLOGIES INCORPORATED

         12000 BUS POWER SYSTEM SIMULATOR--PSS®E-22.0

 INITIATED AT LOAD FLOW ENTRY POINT ON THU MAR 24, 1994  11:15

 ACTIVITY? read,area
 ENTER INPUT FILE NAME (0 TO EXIT, 1 FOR TERMINAL): INDAT.DAT
 ENTER UP TO 20 AREA NUMBERS
1,2,4
 ENTER UP TO 20 AREA NUMBERS
0
```

Get detailed representation of areas 1, 2, and 4 from file INDAT with activity READ,AREA

```
 ENTER 1 TO APPEND DATA TO THE WORKING CASE: 0
 ENTER 1 TO CHANGE CODES OF BOUNDARY BUSES: 0
```

Disable boundary bus identification because type codes should be retained as 1, 2, and 3; not 5, 6, and 7

```
 ENTER: 1 FOR ALL DATA WITHIN SPECIFIED SUBSYSTEM
        2 FOR TIES FROM SPECIFIED SUBSYSTEM
        3 FOR ALL DATA PLUS TIES: 1

 ENTER IC, SBASE

 ENTER TWO LINE HEADING

 ENTER BUS DATA

 ENTER GENERATOR DATA

 ENTER BRANCH DATA

 ENTER TRANSFORMER ADJUSTMENT DATA

 ENTER AREA INTERCHANGE DATA

 ENTER TWO-TERMINAL DC LINE DATA

 ENTER SWITCHED SHUNT DATA

 ENTER TRANSFORMER IMPEDANCE CORRECTION DATA

 ENTER MULTI-TERMINAL DC LINE DATA

 ENTER MULTI-SECTION LINE DATA

 ENTER ZONE NAME DATA

 ENTER AREA TRANSACTION DATA

 BUILDING TABLES--WAIT...

 ACTIVITY? read
 ENTER INPUT FILE NAME (0 TO EXIT, 1 FOR TERMINAL): FILE-B.DAT
```

Append area 3 data contained in FILE-B, with activity READ

```
 ENTER IC, SBASE

 ENTER TWO LINE HEADING

 ENTER BUS DATA

 ENTER GENERATOR DATA

 ENTER BRANCH DATA

 ENTER TRANSFORMER ADJUSTMENT DATA

 ENTER AREA INTERCHANGE DATA

 ENTER TWO-TERMINAL DC LINE DATA

 ENTER SWITCHED SHUNT DATA

 ENTER TRANSFORMER IMPEDANCE CORRECTION DATA

 ENTER MULTI-TERMINAL DC LINE DATA

 ENTER MULTI-SECTION LINE DATA

 ENTER ZONE NAME DATA

 ENTER AREA TRANSACTION DATA
```

Figure 8.5. Alternative Method of Combining Area 3 Data with Detailed Representation of Areas 1, 2, and 4 (Sheet 1 of 5)

```
 BUILDING TABLES--WAIT...

 ACTIVITY? read,area
 ENTER INPUT FILE NAME (0 TO EXIT, 1 FOR TERMINAL): INDAT.DAT
 ENTER UP TO 20 AREA NUMBERS
1 2 4
 ENTER UP TO 20 AREA NUMBERS
0
 ENTER 1 TO APPEND DATA TO THE WORKING CASE: 1
 ENTER 1 TO CHANGE CODES OF BOUNDARY BUSES: 0

 ENTER: 1 FOR ALL DATA WITHIN SPECIFIED SUBSYSTEM
        2 FOR TIES FROM SPECIFIED SUBSYSTEM
        3 FOR ALL DATA PLUS TIES: 2

 ENTER IC, SBASE

 ENTER TWO LINE HEADING

 ENTER BUS DATA

 ENTER GENERATOR DATA

 ENTER BRANCH DATA

 ENTER TRANSFORMER ADJUSTMENT DATA

 ENTER AREA INTERCHANGE DATA

 ENTER TWO-TERMINAL DC LINE DATA

 ENTER SWITCHED SHUNT DATA

 ENTER TRANSFORMER IMPEDANCE CORRECTION DATA

 ENTER MULTI-TERMINAL DC LINE DATA

 ENTER MULTI-SECTION LINE DATA

 ENTER ZONE NAME DATA

 ENTER AREA TRANSACTION DATA

 BUILDING TABLES--WAIT...

 ACTIVITY? solv

 ITER DELTAV/TOL  BUS    REAL(DELTAV)   IMAG(DELTAV)
   1      0.526  1201      0.5169E-04    -0.9918E-05

 REACHED TOLERANCE IN    1 ITERATIONS

 LARGEST MISMATCH:     0.09 MW    -1.03 MVAR      1.04 MVA-BUS  1404 [EDUM     18.0]
 SYSTEM TOTAL ABSOLUTE MISMATCH:                  5.50 MVA

 ACTIVITY? fnsl

 ORDERING NETWORK
 DIAGONALS =     15   OFF-DIAGONALS =     21   MAX SIZE =     34

 ENTER ITERATION NUMBER FOR VAR LIMITS
  0 FOR IMMEDIATELY, -1 TO IGNORE COMPLETELY:

 ITER    DELTAP    BUS      DELTAQ    BUS     DELTA/V/    BUS    DELTAANG    BUS
   0     0.0014( 1402)     0.0116( 1402)
                                               0.00149(  800)    0.00051( 1300)
   1     0.0000( 1100)     0.0664(  800)
                                               0.00143(  800)    0.00037( 1300)
   2     0.0000( 1100)     0.0228( 1402)
                                               0.00007( 1401)    0.00000( 1300)
   3     0.0000(  300)     0.0010( 1402)
                                               0.00000( 1402)    0.00000( 1402)
   4     0.0000(  400)     0.0001( 1401)

 REACHED TOLERANCE IN    4 ITERATIONS

 LARGEST MISMATCH:     0.00 MW    -0.01 MVAR      0.01 MVA-BUS  1401 [WCOND    18.0]
 SYSTEM TOTAL ABSOLUTE MISMATCH:                  0.04 MVA
```

Pick up tie branches between the equivalent and study system from file INDAT with activity READ, AREA

Solve composite power flow case with activity SOLV

Complete solution with activity FNSL

Figure 8.6. Alternative Method of Combining Area 3 Data with Detailed Representation of Areas 1, 2, and 4 (Sheet 2 of 5)

```
ACTIVITY? pout,all  <--------------------------------------  Verify solution

ENTER OUTPUT DEVICE CODE:
 0 FOR NO OUTPUT        1 FOR CRT TERMINAL
 2 FOR A FILE           3 FOR QMS PS2000
 4 FOR QMS_PS800        5 FOR HARD COPY TERMINAL
 6 FOR ALTERNATE SPOOL DEVICE: 1

     PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS®E      THU MAR 24, 1994  11:18
SAMPLE SYSTEM FOR PSS®E MANUAL                                          RATING
1100KV DC CASE                                                           SET A

BUS    100 NUCLEAR  345 AREA CKT     MW      MVAR     MVA  %I 1.0400PU  -2.06  100
 GENERATION               1      2000.0     11.1R 2000.0  91 358.80KV
 TO    200 HYDRO     345   1  1   -168.7     -3.5   168.8  19
 TO    200 HYDRO     345   1  2   -168.7     -3.5   168.8  19
 TO    300 WEST      345   1  1    411.8    -26.6   412.7  47
 TO    300 WEST      345   1  2    411.8    -26.6   412.7  47
 TO   1550 MIDPNTL   345   4  1    756.9     35.7   757.8  86
 TO   1550 MIDPNTL   345   4  2    756.9     35.7   757.8  86

BUS    200 HYDRO     345 AREA CKT     MW      MVAR     MVA  %I 1.0400PU   0.00  200
 GENERATION               1      1237.1   -124.9R 1243.3  71 358.80KV
 TO    100 NUCLEAR   345   1  1    169.4    -40.8   174.2  20
 TO    100 NUCLEAR   345   1  2    169.4    -40.8   174.2  20
 TO    400 EAST      345   1  1    449.1    -21.7   449.7  51
 TO    400 EAST      345   1  2    449.1    -21.7   449.7  51

     PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS®E      THU MAR 24, 1994  11:18
SAMPLE SYSTEM FOR PSS®E MANUAL                                          RATING
1100KV DC CASE                                                           SET A

BUS    300 WEST      345 AREA CKT     MW      MVAR     MVA  %I 0.9998PU -22.65  300
                          1                                    344.93KV
 TO    100 NUCLEAR   345   1  1   -395.6    -20.4   396.2  47
 TO    100 NUCLEAR   345   1  2   -395.6    -20.4   396.2  47
 TO    400 EAST      345   1  1    -16.4    -40.7    43.9   5
 TO    500 WESTLV    230   2  1    403.8     40.8   405.9  81 1.0000LK
 TO    500 WESTLV    230   2  2    403.8     40.8   405.9  81 1.0000LK

BUS    400 EAST      345 AREA CKT     MW      MVAR     MVA  %I 1.0042PU -22.46  400
                          1                                    346.44KV
 TO    200 HYDRO     345   1  1   -429.9      1.3   429.9  50
 TO    200 HYDRO     345   1  2   -429.9      1.3   429.9  50
 TO    300 WEST      345   1  1     16.4     -5.8    17.4   2
 TO    600 EASTLV    230   2  1    421.7      1.6   421.7  56 1.0000LK
 TO    600 EASTLV    230   2  2    421.7      1.6   421.7  56 1.0000LK

     PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS®E      THU MAR 24, 1994  11:18
SAMPLE SYSTEM FOR PSS®E MANUAL                                          RATING
1100KV DC CASE                                                           SET A

BUS    500 WESTLV    230 AREA CKT     MW      MVAR     MVA  %I 0.9955PU -26.14  500
                          2                                    228.97KV
 TO LOAD-PQ                        750.0      0.0   750.0
 TO    300 WEST      345   1  1   -403.8    -16.1   404.2  81 1.0000UN
 TO    300 WEST      345   1  2   -403.8    -16.1   404.2  81 1.0000UN
 TO    700 SWURB     230   2  1     28.8     16.1    33.0   7
 TO    700 SWURB     230   2  2     28.8     16.1    33.0   7

BUS    600 EASTLV    230 AREA CKT     MW      MVAR     MVA  %I 1.0049PU -24.86  600
                          2                                    231.13KV
 TO LOAD-PQ                        500.0      0.0   500.0
 TO    400 EAST      345   1  1   -421.7     16.0   422.0  56 1.0000UN
 TO    400 EAST      345   1  2   -421.7     16.0   422.0  56 1.0000UN
 TO    700 SWURB     230   2  1    136.8     53.4   146.8  29
 TO    700 SWURB     230   2  2    136.8     53.4   146.8  29
 TO    800 SETOUN    230   2  1     34.9    -69.4    77.7  15
 TO    800 SETOUN    230   2  2     34.9    -69.4    77.7  15

     PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS®E      THU MAR 24, 1994  11:18
SAMPLE SYSTEM FOR PSS®E MANUAL                                          RATING
1100KV DC CASE                                                           SET A

BUS    700 SWURB     230 AREA CKT     MW      MVAR     MVA  %I 0.9911PU -26.48  700
                          2                                    227.95KV
 TO LOAD-PQ                       1250.0      0.0  1250.0
 TO    500 WESTLV    230   2  1    -28.8    -20.3    35.2   7
 TO    500 WESTLV    230   2  2    -28.8    -20.3    35.2   7
 TO    600 EASTLV    230   2  1   -136.4    -53.3   146.4  30
 TO    600 EASTLV    230   2  2   -136.4    -53.3   146.4  30
 TO   1201 SWIGA     230   3  1   -459.8     73.6   465.6  94
 TO   1201 SWIGA     230   3  2   -459.8     73.6   465.6  94
```

Figure 8.7. Alternative Method of Combining Area 3 Data with Detailed Representation of Areas 1, 2, and 4 (Sheet 3 of 5)

```
BUS   800 SETOUN    230 AREA CKT     MW      MVAR      MVA   %I 1.0185PU -25.34   800
                          2                                     234.26KV
 TO LOAD-PQ                        500.0      0.0    500.0
 TO    600 EASTLV   230    2  1     -34.8     66.0     74.6  15
 TO    600 EASTLV   230    2  2     -34.8     66.0     74.6  15
 TO   1100 CATNIP   230    2  1    -248.1   -109.9    271.4  53
 TO   1100 CATNIP   230    2  2    -248.1   -109.9    271.4  53
 TO   1300 SERGA    230    3  1      65.9     87.8    109.8  22

     PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS®E      THU MAR 24, 1994  11:18
SAMPLE SYSTEM FOR PSS®E MANUAL                                          RATING
1100KV DC CASE                                                           SET A

BUS  1100 CATNIP    230 AREA CKT     MW      MVAR      MVA   %I 1.0611PU -21.28 1100
 GENERATION               2        500.0    250.0H   559.0 112 244.04KV
 TO    800 SETOUN   230    2  1    250.0    125.0    279.5  53
 TO    800 SETOUN   230    2  2    250.0    125.0    279.5  53

BUS  1201 SWIGA     230 AREA CKT     MW      MVAR      MVA   %I 0.9942PU -14.85 1201
                          3                                     228.66KV
 TO LOAD-PQ                       1000.0      0.0   1000.0
 TO SHUNT                            0.0   -199.3    199.3
 TO    700 SWURB    230    2  1    467.5     11.8    467.7  94
 TO    700 SWURB    230    2  2    467.5     11.8    467.7  94
 TO   1300 SERGA    230    3  1    475.3     43.7    477.3  96
 TO   1300 SERGA    230    3  2    475.3     43.7    477.3  96
 TO   1403 WDUM    18.0    3  99 -1442.9     44.1   1443.5
 TO   1404 EDUM    18.0    3  99 -1442.9     44.1   1443.5
ENTER 0 TO END LIST, 1 FOR NEXT PAGE:

     PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS®E      THU MAR 24, 1994  11:18
SAMPLE SYSTEM FOR PSS®E MANUAL                                          RATING
1100KV DC CASE                                                           SET A

BUS  1300 SERGA     230 AREA CKT     MW      MVAR      MVA   %I 0.9779PU -26.77 1300
                          3                                     224.91KV
 TO LOAD-PQ                       1000.0      0.0   1000.0
 TO    800 SETOUN   230    2  1     -65.5    -91.6    112.6  23
 TO   1201 SWIGA    230    3  1    -467.3     45.8    469.5  96
 TO   1201 SWIGA    230    3  2    -467.3     45.8    469.5  96

BUS  1401 WCOND    18.0 AREA CKT     MW      MVAR      MVA   %I 1.0259PU  -7.22 1401
 GENERATION               3          0.0    653.5R   653.5  82 18.466KV
 TO SHUNT                            0.0   -105.2    105.2
 TO   1403 WDUM    18.0    3  1      0.0    758.8    758.8  74

BUS  1402 ECOND    18.0 AREA CKT     MW      MVAR      MVA   %I 1.0259PU  -7.22 1402
 GENERATION               3          0.0    653.5R   653.5  82 18.466KV
 TO SHUNT                            0.0   -105.2    105.2
 TO   1404 EDUM    18.0    3  1      0.0    758.8    758.8  74

     PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS®E      THU MAR 24, 1994  11:18
SAMPLE SYSTEM FOR PSS®E MANUAL                                          RATING
1100KV DC CASE                                                           SET A

BUS  1403 WDUM     18.0 AREA CKT     MW      MVAR      MVA   %I 1.0000PU  -7.22 1403
                          3                                     18.000KV
 TO SHUNT                            0.0      0.0      0.0
 TO   1600 MINE     INVERTER# 1 -1444.3    590.9   1560.6      1.0000RG  18.17RG
 TO   1201 SWIGA    230    3  99  1444.3    148.8   1452.0
 TO   1401 WCOND   18.0    3  1      0.0   -739.6    739.6  74
 TO   1404 EDUM    18.0    3  99     0.0      0.0      0.0

BUS  1404 EDUM     18.0 AREA CKT     MW      MVAR      MVA   %I 1.0000PU  -7.22 1404
                          3                                     18.000KV
 TO SHUNT                            0.0      0.0      0.0
 TO   1600 MINE     INVERTER# 2 -1444.3    590.9   1560.6      1.0000RG  18.17RG
 TO   1201 SWIGA    230    3  99  1444.3    148.8   1452.0
 TO   1402 ECOND   18.0    3  1      0.0   -739.6    739.6  74
 TO   1403 WDUM    18.0    3  99     0.0      0.0      0.0

     PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS®E      THU MAR 24, 1994  11:18
SAMPLE SYSTEM FOR PSS®E MANUAL                                          RATING
1100KV DC CASE                                                           SET A
```

Figure 8.8. Alternative Method of Combining Area 3 Data with Detailed Representation of Areas 1, 2, and 4 (Sheet 4 of 5)

```
     PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS®E      THU MAR 24, 1994  11:18
SAMPLE SYSTEM FOR PSS®E MANUAL                                           RATING
1100KV DC CASE                                                            SET A

BUS   1550 MIDPNTL  345 AREA CKT    MW      MVAR     MVA  %I 1.0285PU  -6.65 1550
                          4                                 354.85KV
 TO LOAD-PQ                      1500.0     0.0  1500.0
 TO    100 NUCLEAR  345    1  1  -750.0     0.0   750.0  86
 TO    100 NUCLEAR  345    1  2  -750.0     0.0   750.0  86
BUS  1600 MINE     765 AREA CKT    MW     MVAR     MVA  %I 1.0400PU   0.00 1600
 GENERATION               4      3000.0   835.4R 3114.2  97 795.60KV
 TO   1403 WDUM     RCTIFIER# 1  1500.0   417.7  1557.1     1.0313RG   6.76RG
 TO   1404 EDUM     RCTIFIER# 2  1500.0   417.7  1557.1     1.0313RG   6.76RG

ACTIVITY? stop
```

Figure 8.9. Alternative Method of Combining Area 3 Data with Detailed Representation of Areas 1, 2, and 4 (Sheet 5 of 5)

8.2. Activity EEQV

8.2.1. Using EEQV

Activity EEQV requires the case with its bus voltage corresponding to a solved power flow condition to be in the working file. Activity EEQV runs its operations and places its results in the working file.

Activity EEQV can be invoked with the standard suffixes. For the purpose of illustration, assume that the activity is called with the suffix, AREA. Regardless of what suffix is used, the activity queries the user to indicate which area and zone boundary buses are to be retained. Boundary buses between the study subsystem and the subsystem to be equivalenced are automatically retained. This question only affects the buses in the subsystem to be equivalenced. Figure 8.10, “Boundary Bus Retention” shows two buses that would be affected by this question. If phase shifters exist in the external system (subsystem to be equivalenced), the user will be asked if those buses, the connected buses, and buses remotely regulated by a generator should be retained. If the user specifies a 0 (no), the program will reset VSCHED to VACTUAL at the retained generator bus before building the equivalent and eliminating the remotely regulated bus. The next question gives the user the ability to eliminate the smaller plants, by specifying the minimum generation for a plant to be retained. The magnitude of the real and reactive generation must be below this threshold for a bus to be eliminated. All generators with generation above this magnitude will be retained in the subsystem.

To eliminate large generation, the user should use activities GNET or NETG before entering EEQV. The user must then state whether existing branches between retained buses are to be retained and, finally, indicate a branch tolerance. Figure 8.11, “EEQV Sequence (Sheet 1 of 2)” shows an example sequence of using EEQV.

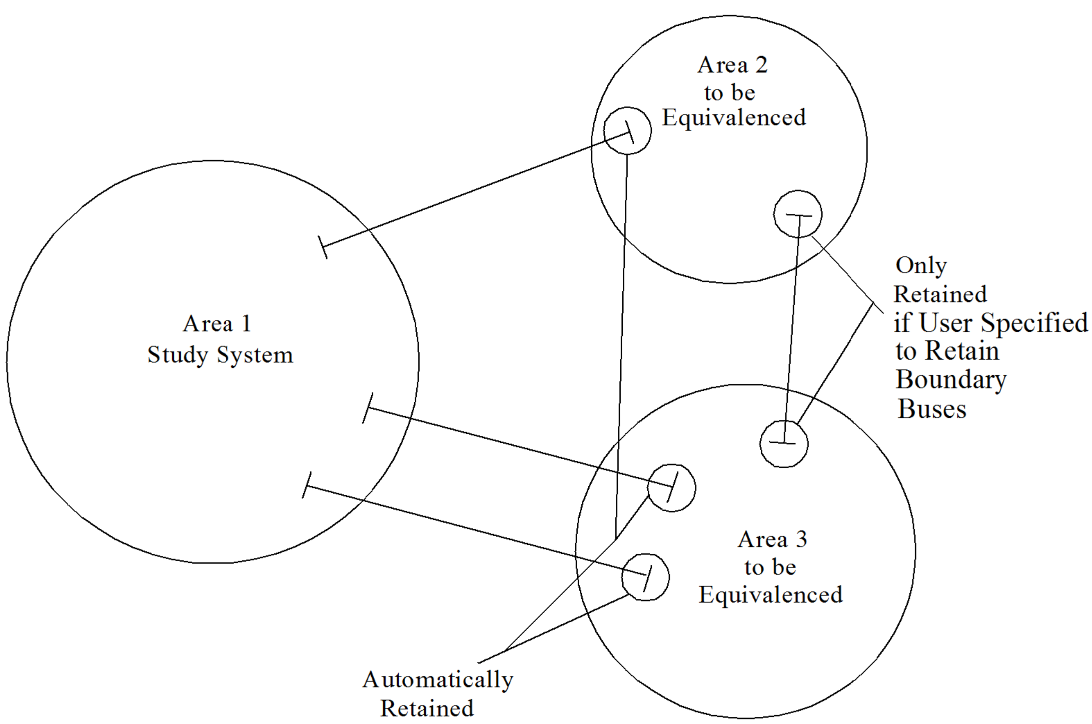


Figure 8.10. Boundary Bus Retention

```
 ACTIVITY? case savnw <-------------------------------- Get case

 PSS®E PROGRAM APPLICATION GUIDE EXAMPLE
 BASE CASE INCLUDING SEQUENCE DATA

 CASE savnw.sav WAS SAVED ON TUE NOV 06, 1990  09:59

 ACTIVITY? fdns

 ENTER ITERATION NUMBER FOR VAR LIMITS
  0 FOR IMMEDIATELY, -1 TO IGNORE COMPLETELY:

 ITER    DELTAP   BUS      DELTAQ   BUS      DELTA/V/    BUS    DELTAANG    BUS
   0     0.0000(  154)     0.0718( 3008)
                                              0.00000(     0)    0.00000(  102)

   0     0.0000( 3008)     0.0001(  205)
                                              0.00000(   206)    0.00000(     0)

   1     0.0001(  205)     0.0001(  154)


 REACHED TOLERANCE IN   1 ITERATIONS

 LARGEST MISMATCH:     0.01 MW     0.00 MVAR      0.01 MVA-BUS   205 [SUB230    230]
 SYSTEM TOTAL ABSOLUTE MISMATCH:                  0.05 MVA

 ACTIVITY? gnet <------------------------------ Net large generators

 USER SPECIFIES THOSE TO BE NETTED
 ENTER UP TO 20 BUS NUMBERS
102
 ENTER UP TO 20 BUS NUMBERS
0

 GENERATION AT     1 BUSES NETTED WITH THEIR LOAD

 ACTIVITY? chng

 ENTER CHANGE CODE:
  0 = EXIT ACTIVITY                  1 = BUS DATA
  2 = GENERATOR DATA                 3 = BRANCH DATA
  4 = TRANSFORMER DATA               5 = AREA INTERCHANGE DATA
  6 = TWO-TERMINAL DC LINE DATA      7 = SOLUTION PARAMETERS
  8 = CASE HEADING                   9 = SWITCHED SHUNT DATA
 10 = IMPEDANCE CORRECTION TABLES   11 = MULTI-TERMINAL DC DATA
 12 = ZONE DATA                     13 = AREA TRANSACTIONS DATA: 1

 ENTER BUS NUMBER (0 FOR NEW CHANGE CODE, -1 TO EXIT): 151 <----- Make bus 151 a type 5
                                                                  bus to save it also

 BUS DATA FOR BUS   151 [NUCPANT  500]:
   CODE     PLOAD     QLOAD        S H U N T
 OLD  1      0.00      0.00      0.00  -600.00 CHANGE IT? 1
 ENTER CODE, PLOAD, QLOAD, G, B
5
 NEW  5      0.00      0.00      0.00  -600.00

     AREA    VOLT    ANGLE   NAME     BASVLT LOSZON
 OLD    1   1.0079   12.45 NUCPANT   500.000     1 CHANGE IT? -1

 ENTER CHANGE CODE:
  0 = EXIT ACTIVITY                  1 = BUS DATA
  2 = GENERATOR DATA                 3 = BRANCH DATA
  4 = TRANSFORMER DATA               5 = AREA INTERCHANGE DATA
  6 = TWO-TERMINAL DC LINE DATA      7 = SOLUTION PARAMETERS
  8 = CASE HEADING                   9 = SWITCHED SHUNT DATA
 10 = IMPEDANCE CORRECTION TABLES   11 = MULTI-TERMINAL DC DATA
 12 = ZONE DATA                     13 = AREA TRANSACTIONS DATA:

 ACTIVITY? eeqv,area <---------------------------------- EEQV by area
```

Figure 8.11. EEQV Sequence (Sheet 1 of 2)

```
 WARNING: SEQUENCE DATA WILL NOT BE EQUIVALENCED

 USER SPECIFIES SUBSYSTEM TO BE EQUIVALENCED
 ENTER UP TO 20 AREA NUMBERS
1,2                                                       Areas 1 and 2
 ENTER UP TO 20 AREA NUMBERS
0

 ENTER 1 TO RETAIN AREA BOUNDARY BUSES: 1         Retain area but not zone boundaries

 ENTER 1 TO RETAIN ZONE BOUNDARY BUSES: 0

 ENTER 1 TO RETAIN BUSES CONTROLLED BY REMOTE GENERATION OR SWITCHED SHUNT: 0

 ENTER MINIMUM GENERATION FOR RETAINING GENERATOR BUSES                Do not
   (CARRIAGE RETURN TO KEEP ALL ON-LINE GENERATOR BUSES): 100          retain
                                                                       remotes
 ENTER 1 TO RETAIN EXISTING BRANCHES BETWEEN RETAINED BUSES: 0

 REBUILDING TABLES--WAIT...
    2 RADIAL AND TWO POINT BUSES EQUIVALENCED
 DIAGONALS =      3  OFF-DIAGONALS =      1  MAX SIZE =     2

 ENTER BRANCH THRESHOLD TOLERANCE: 3

 ENTER 1 TO NET LOAD AND SHUNT AT RETAINED BUSES: 0

 REBUILDING TABLES--WAIT...

 ACTIVITY? fdns                                          Check result

 ORDERING NETWORK
 DIAGONALS =     17  OFF-DIAGONALS =     31  MAX SIZE =    46

 ENTER ITERATION NUMBER FOR VAR LIMITS
  0 FOR IMMEDIATELY, -1 TO IGNORE COMPLETELY:

 ITER    DELTAP    BUS      DELTAQ    BUS      DELTA/V/    BUS    DELTAANG   BUS
   0     0.0001(  154)     0.0718( 3008)
                                                0.00000(     0)    0.00000(  154)
   0     0.0000(  205)     0.0001(  154)
                                                0.00000(   154)    0.00000(    0)
   1     0.0001(  205)     0.0000(  152)


 REACHED TOLERANCE IN    1 ITERATIONS

 LARGEST MISMATCH:     0.01 MW     0.00 MVAR      0.01 MVA-BUS   205 [SUB230    230]
 SYSTEM TOTAL ABSOLUTE MISMATCH:                  0.04 MVA

 ACTIVITY? save eeqv.sav                                          Saved case
```

Figure 8.12. EEQV Sequence (Sheet 2 of 2)

8.3. Boundaries and Boundary Buses

8.3.1. Boundary

A boundary cuts a set of tie-lines but passes through no buses. A boundary bus is part of only one area, as shown in Figure 8.13, "Separation of Complete Network into Study System and External Systems by Boundaries".

An equivalent makes more efficient use of storage when the ratio of branches to buses in the equivalent is reduced. The relative efficiency of different equivalents of a given system is best determined by trial and error. As a general rule, however, reducing a system into a number of small equivalents is more efficient than reducing a large system in one step to produce a single equivalent.

8.3.2. Boundary Bus Type Codes

Three special bus type codes are used to designate boundary buses at various stages of the equivalent construction processes.

Type 5

As for Type 1 (load bus); boundary bus or a bus that is not to be deleted by equivalencing.

Type 6

As for Type 2 (generator bus); boundary bus.

Type 7

As for Type 3 (swing bus); boundary bus.

Several activities of PSS®E change the type codes of boundary buses back and forth between 1, 2, 3 and 5, 6, 7, respectively. The user may also change type codes via activity CHNG.

Type codes 5, 6, 7 are valid only during equivalent construction and system data processing operations. Type codes 5, 6, or 7 must be returned to 1, 2, or 3, respectively, before invoking any optimal ordering, factorization, generator or load conversion, or solution activity.

8.3.3. Handling dc Transmission in Equivalents

Activity EEQV automatically retains converter buses of unblocked dc transmission lines. Hence, all buses that are affected by dc transmission must become part of a study system before commencing the construction of an equivalent.

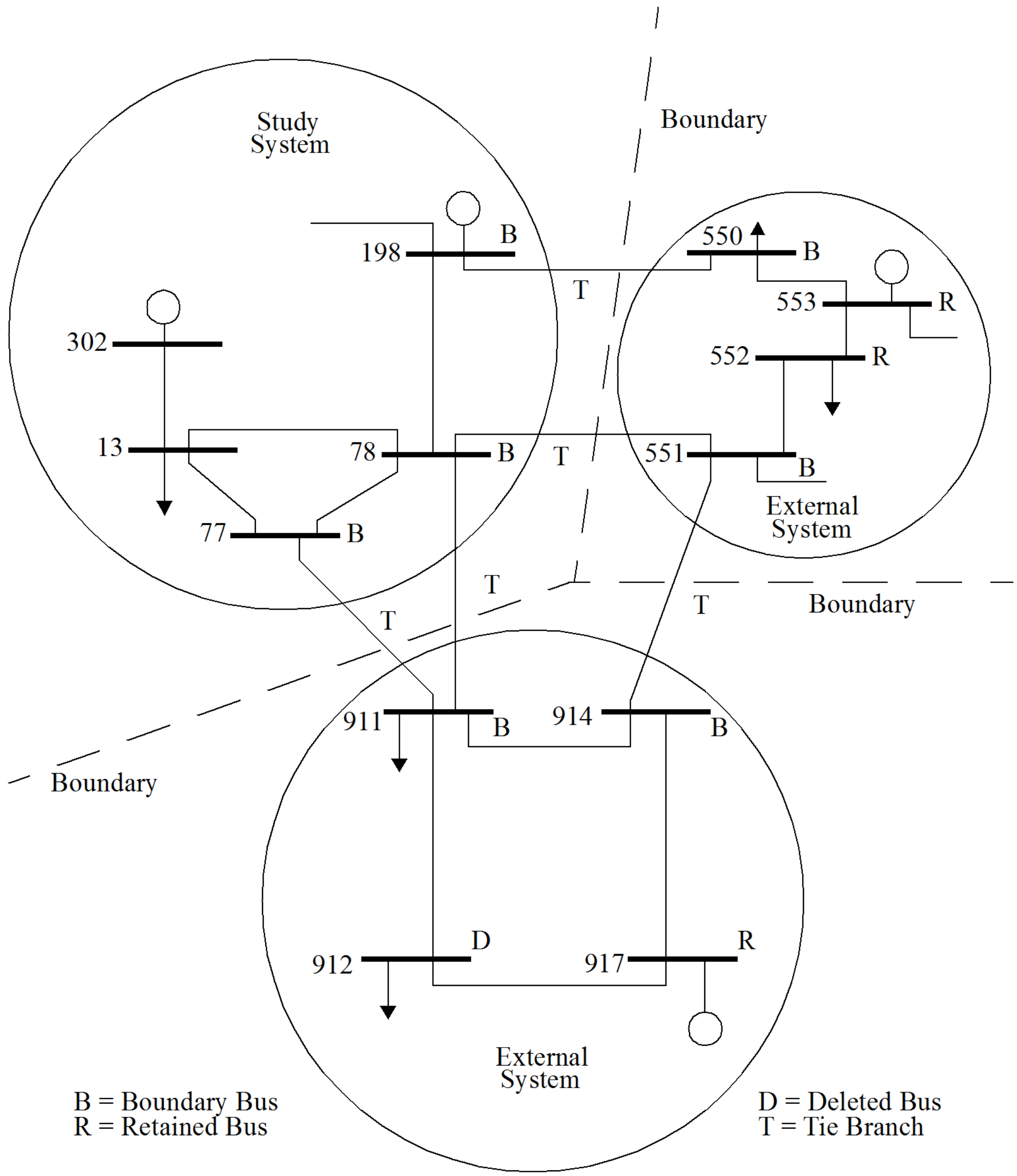


Figure 8.13. Separation of Complete Network into Study System and External Systems by Boundaries

8.4. Combining System Sections

8.4.1. Original Data Sources

Before any power flow study can be made or an equivalent can be constructed, it is necessary to build an appropriate power flow case in the working file. This working case is usually the result of combining together sections of system representation from a variety of sources. System sections may originate in many ways; for example, from:

- Previous studies made in PSS®E.
- Studies made on another power flow program.
- A centralized data bank.
- Fresh data preparation.

The data for a system section may take a number of forms including:

- The complete content of a power flow input data file.
- Selected areas from the power flow input data file of a larger system, parts of which are extraneous to the present purpose.
- The complete content of a PSS®E working case.
- Selected areas or groups of buses from a PSS ®E working case, parts of which are extraneous.

The isolation of system sections from extraneous data and their combination to form a working case is handled by activities EXTR and READ. These activities are used both to prepare a working case for the construction of an equivalent and to combine previously constructed equivalents with other system sections.

When considering EXTR and READ, that there is no difference in form between a file of standard power flow input data and an electrical equivalent; both are specifications of power system buses and branches and both are handled by activity READ in exactly the same way.

8.4.2. Activity EXTR

Activity EXTR is used when the original data source is a PSS ®E working case. EXTR runs two functions:

- It discards system branches and buses from the working case.
- It identifies boundary buses and changes their type from 1, 2, or 3 to 5, 6, or 7, respectively.

To use EXTR, the user brings a case that includes the desired system segment into the working file, and then specifies to EXTR the numbers of those buses that are not a part of the desired segment and these buses are discarded from the power flow working file.

EXTR provides the user with the option for automatic identification of boundary buses. When this is selected, EXTR changes the type code of each bus that remains in the working file, but was previously connected to a bus that has been discarded. The type codes are changed to 5, 6, or 7, as appropriate. This option does not necessarily identify all boundary buses of the system section that is left in the working file. This system section may well be intended to have interconnections that were not present in the original working case; in this case the type code of load buses that are to be boundary buses, but which were not identified by EXTR, must be changed manually to 5 via CHNG. It is most convenient when the buses of each natural system segment appear with contiguous bus numbers in the working case. This favors the grouping of bus numbers by geographic location or company service area rather than by voltage level.

8.4.3. Activity EXTR,AREA

EXTR,AREA is identical in function to EXTR, except the user specifies a group of buses. The manner in which bus numbers are assigned has no effect on the convenience of use of EXTR,AREA. As a general rule EXTR,AREA is preferred for equivalent building work in large-scale system studies, while EXTR is preferable when working on the equivalencing of small subsections of a system.

8.4.4. Application of EXTR and EXTR,AREA

Figure 8.14, "Use of EXTR to Prepare External System for Equivalent Construction" illustrates the use of EXTR and EXTR,AREA in conjunction with CHNG and EEQV to produce equivalents. The case involves operations on the working case only, with data files being involved only to receive the final result of the equivalent construction process.

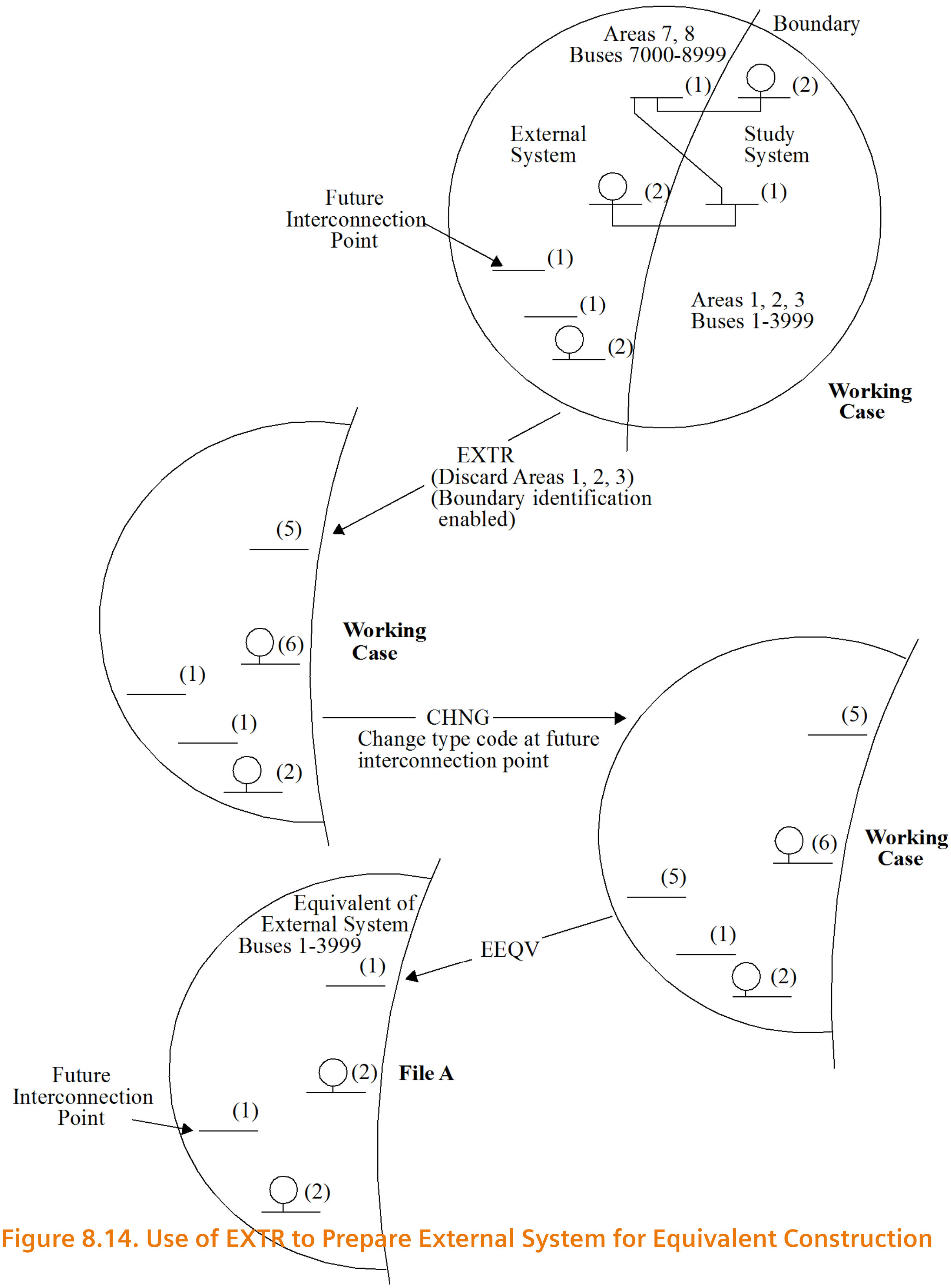


Figure 8.14. Use of EXTR to Prepare External System for Equivalent Construction

8.4.5. Activity READ,AREA

Activity READ,AREA is used when the desired system segment is an area or group of areas within a system where the complete data is contained in a PSS®E power flow input data file. READ,AREA runs two functions: First, it appends to the working case all buses in the group of areas specified by the user, and all branches having both ends at buses that are already in the working file (whether these buses were placed there during this execution of READ,AREA or were already there). Second, it identifies as a boundary bus any bus that is in one of the selected areas and connected to a bus that is not in the working file. The type codes of these boundary buses are changed to 5, 6, or 7 as appropriate. The boundary bus identification may be enabled or disabled at the option of the user.

Figure 8.15, "Use of READ,AREA to Join Equivalent with New Study System Representation" illustrates the use of READ,AREA to follow up on the operation shown in Figure 8.14, "Use of EXTR to Prepare External System for Equivalent Construction", which created an equivalent of areas 7 and 8 in file A. Any new representation of areas 1, 2, and 3 provided in power flow input data file N would be combined with the equivalent to provide a new working case as shown in Figure 8.15, "Use of READ,AREA to Join Equivalent with New Study System Representation". READ is run first in this example to place the equivalent in the working file before executing READ,AREA to ensures that the boundary buses at both ends of all tie branches are in the working case before READ,AREA attempts to pick up branches. All tie branches will be added as required.

8.4.6. Compatibility of Bus Numbers

READ,AREA may be used to add data to the working case *only* after it has been ensured that no new bus to be added to the working case has the same number as a bus that is already in the working case or is to be placed there by a subsequent READ or READ,AREA operation.

For example, the example of Figure 8.14, "Use of EXTR to Prepare External System for Equivalent Construction" used bus number 1-3999 for areas 1, 2, 3 and bus numbers 7000- 8999 for areas 7, 8. The new representation of areas 1, 2, and 3 in file N may include buses that are not present in the original working case of Figure 8.14, "Use of EXTR to Prepare External System for Equivalent Construction". It is *not advisable* to assign such new buses numbers between 7000 and 8999 because numbers in this range may still be used for buses that were retained in the equivalent of areas 7, 8.

8.4.7. Activity RAWD

Activity RAWD translates the PSS®E power flow working case into the power flow input data file form. It is, in effect, the inverse of activity READ. This activity allows a power flow case that has been built up within PSS®E to be processed by activity READ,AREA and other activities requiring data in input data file form.

A common use of RAWD is the simple combining of two sections of a power flow that have been built up in separate PSS®E saved cases. To join two such saved cases, one of the two must be translated into input data file form as shown in Figure 8.16, "Use of RAWD to Allow Combination of Two Compatible PSS®E Saved Case Files".

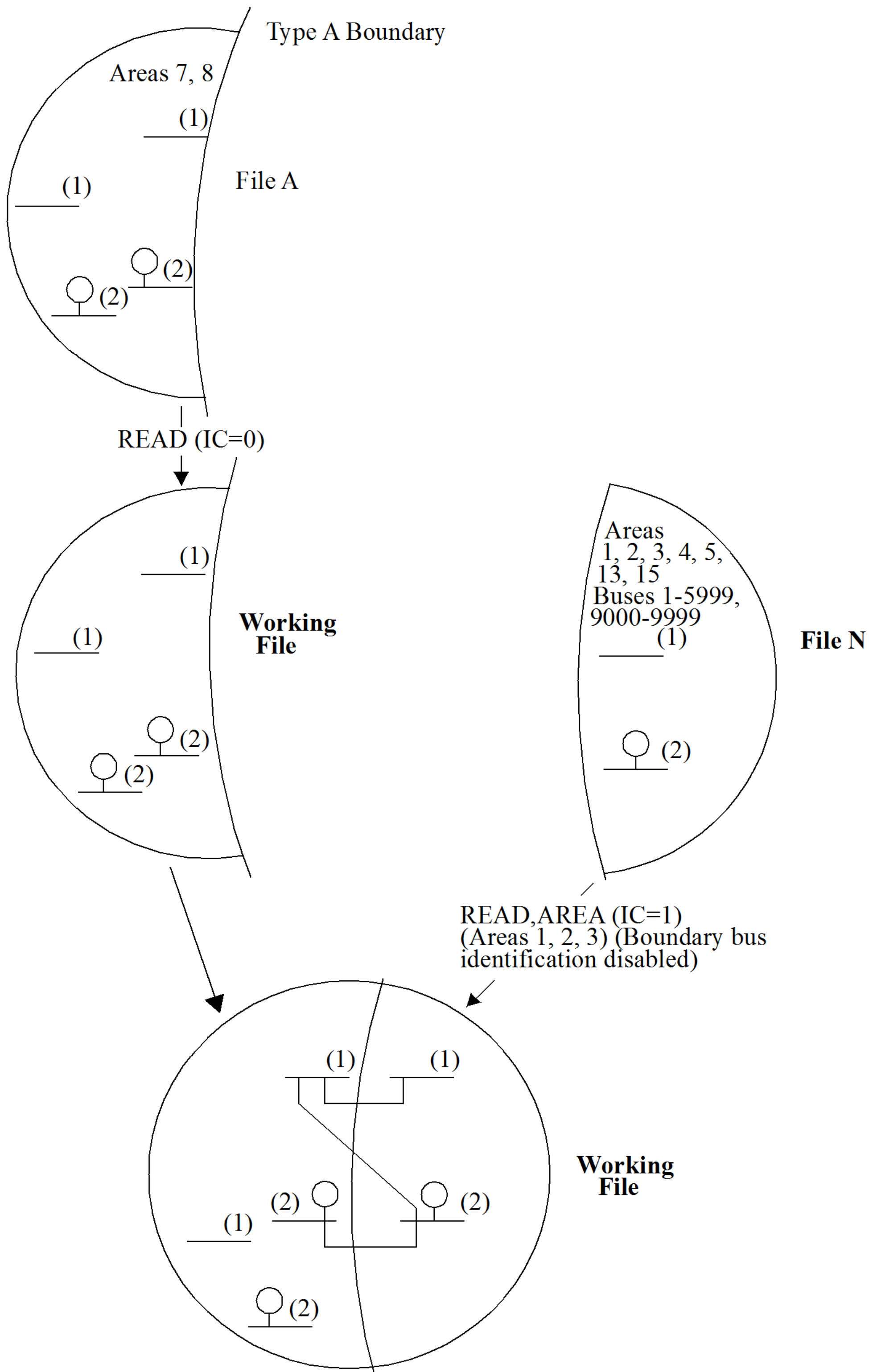


Figure 8.15. Use of READ,AREA to Join Equivalent with New Study System Representation

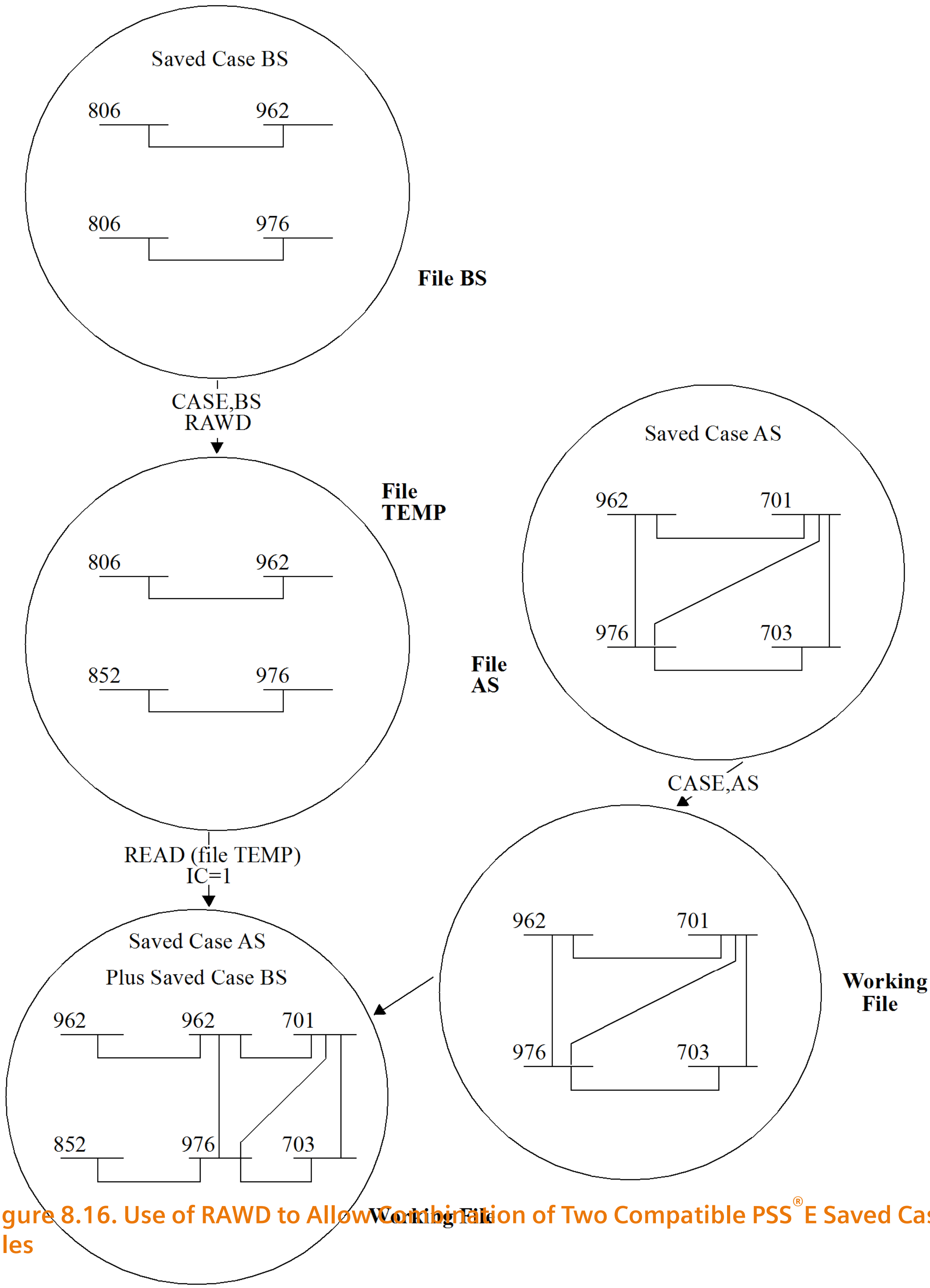


Figure 8.16. Use of RAWD to Allow Combination of Two Compatible PSS®E Saved Case Files

8.4.8. Activities NETG and GNET

Activity NETG is used when a large number of generators are to be removed from the working case by netting their output with the load at a bus. NETG replaces generation with equivalent negative load at all buses with these exceptions:

- Buses that are designated by the user at the start of the activity.
- Buses that are indicated by type codes 6 or 7 to be boundary or retained buses.

Activity GNET is identical in function to NETG. It differs from NETG in that the user specifies buses where generation is to be replaced with equivalent negative load.

8.4.9. Combination of Two Systems

This example (Figure 8.1, "Use of Area 3 Data Together with Detailed Representation of Areas 1, 2, and 4 to Make Reduced Size Representation of Complete Sample System (Sheet 1 of 4)") shows how one system may be combined with a new study system representation to build a new working case representing the complete system. The procedure for building a new power flow working case from raw data that is contained in two different source data files is the same as that outlined in Figure 8.15, "Use of READ,AREA to Join Equivalent with New Study System Representation".

The desired representation of area 3 is contained in file FILE-B. The desired data for areas 1, 2, and 4 is imbedded within a complete system specification in file INDAT, as is the tie-line data.

The first step in the process must be made *before* PSS®E is turned on to ensure that the change code, IC, in FILE-B is zero. The user must make the required change in the first line of the file.

With the data for area 3 correctly set up in file FILE-B, PSS®E is turned on and READ is used to initialize the working case and read in the first group of data from FILE-B. Activity READ,AREA is then used to append the detailed representation of areas 1, 2, and 4 onto the representation of area 3.

It is not necessary to change the change code, IC, from 0 to 1 in file INDAT because READ,AREA allows the user to override this data item (READ does not). Boundary bus identification was not enabled in READ,AREA because the data being read was not for use in the construction of an equivalent.

After completion of READ,AREA, the working case contains a complete but unsolved composite power flow case. It is not solved because the study system representation was obtained from an unsolved source; namely, the file INDAT. The case was solved with activity SOLV and full output was printed with Activity POUT,ALL.

8.4.10. Alternative Method of Combining Study System and Equivalent

Figure 8.5, "Alternative Method of Combining Area 3 Data with Detailed Representation of Areas 1, 2, and 4 (Sheet 1 of 5)" shows the dialog for an alternative way of achieving the same combination of two systems that was made by the previous example. In Figure 8.5, "Alternative Method of Combining Area 3 Data with Detailed Representation of Areas 1, 2, and 4 (Sheet 1 of 5)" the area 3 is appended to the study system; the first step is, therefore, to use the file editor to ensure that the change code, IC, in the equivalent file (FILE-B) is unity. The composite system is then built up in three steps by the following activities:

READ,AREA

Pick up the study system.

READ

Pick up the area 3.

READ,AREA

Make a second pass through the data file INDAT and join the two systems by the tie branches.

The remainder of Figure 8.5, “Alternative Method of Combining Area 3 Data with Detailed Representation of Areas 1, 2, and 4 (Sheet 1 of 5)” confirms that the composite system is identical to that obtained in Figure 8.1, “Use of Area 3 Data Together with Detailed Representation of Areas 1, 2, and 4 to Make Reduced Size Representation of Complete Sample System (Sheet 1 of 4)”and that its solution agrees, within tolerance, with that of Figure 8.1, “Use of Area 3 Data Together with Detailed Representation of Areas 1, 2, and 4 to Make Reduced Size Representation of Complete Sample System (Sheet 1 of 4)”.

8.5. Form of the Equivalent

An electrical equivalent is constructed by running a reduction operation on the admittance matrix of the external system that is to be represented by the equivalent. The admittance matrix equation of the external system may be written in the partitioned form

$$\begin{bmatrix} I_1 \\ I_2 \end{bmatrix} = \begin{bmatrix} Y_1 & Y_2 \\ Y_3 & Y_4 \end{bmatrix} \begin{bmatrix} V_1 \\ V_2 \end{bmatrix} \quad (8.1)$$

where I_1 and V_1 are node current and voltage at the nodes to be retained and I_2 and V_2 are node current and voltage at the nodes to be deleted.

The desired form of an equivalent is an equation involving only I_1 and V_1 explicitly, with the I_2 and V_2 variables assumed to be linearly dependent upon I_1 and V_1, and recognized implicitly. The equivalent is obtained by rearranging the second row of Equation 8.1 as

$$V_2 = Y_4^{-1} (I_2 - Y_3 V_1) \quad (8.2)$$

and substituting this into the first row of Equation 8.1 to give

$$I_1 = (Y_1 - Y_2 Y_4^{-1} Y_3) V_1 + Y_2 Y_4^{-1} I_2 \quad (8.3)$$

The first term of Equation 8.3 specifies a set of equivalent branches and static shunt elements connecting the retained nodes, while the second term specifies a set of equivalent currents that must be impressed on the retained nodes to reproduce the effect of load currents at the deleted nodes. These equivalent currents may be translated into equivalent constant real and reactive power loads at the retained buses. The equivalent obtained by translating the two terms of Equation 8.3 into equivalent branches, shunts, and loads is exact in the base case for which the current vector, I_2, was calculated. When voltage conditions at the boundary buses are changed, the equivalent gives an approximation to the change in power flow into the external system. This approximation is good as long as the changes are small, but may become unreliable when boundary bus voltages and power flows into the external system (or its equivalent) deviate from the base values by large amounts.

An electrical equivalent is, therefore, correctly applied when it represents an external system in which the disturbances or switching operations being studied produce only minor effects; but equivalents should not be applied to network segments in the close vicinity of the disturbances or switchings.

Electrical equivalents of this form are constructed by PSS®E activity EEQV. The activity is self-contained and runs all mathematical operations involved in the admittance matrix reduction. This activity leaves the resulting equivalent in the working case. The equivalents produced by EEQV gives an exact reproduction of the self and transfer impedances of the external system as seen from its boundary buses. The net total of load, generation, and losses in the equivalent matches this total in the complete external system as if the bus voltages in the working file were a valid power flow solution. The load, loss, and generation totals in the equivalent may not individually match those of the complete study system, however.

A power flow working case containing elements introduced via an equivalent is identical in form to a power flow case containing only real system elements and may be operated on by all PSS®E activities, including the equivalencing activities. That is, it is permissible to construct an equivalent of an equivalent.

8.6. Overview

An equivalent represents a network that contains many buses, but only a few boundary buses, by a reduced network that contains only the boundary buses and a few of the original buses. Equivalents are used in two circumstances: both to allow larger areas of major interconnected systems to be represented in studies and also to achieve improved computational speed in simulations by removing buses and branches that influence system behavior, but are not of specific interest.

8.7. Radial and Two-Point Type 1 Bus Equivalencing

Often a user will want to run a quick network reduction on parts of the system. Activity RDEQ and EQRD allow the user to specify subsystems in which the user wants to equivalence all radial and optionally two-point Type 1 buses. This activity automatically leaves the new reduced case in the working files.

Both of these activities assign the smaller of each pair of ratings whenever a two-point bus with no load is removed. The activities also block the equivalencing at dc converters.

The use of activity RDEQ or EQRD as a preprocessor to activity EEQV is neither necessary nor helpful.

8.8. Terminology

In discussing the application of equivalents, it is useful to adopt the following terminology:

Study System	A group of buses subject to detailed study; all components are represented explicitly.
External System	A group of buses and branches that connect to and influence a study system, but do not need to be represented in detail.
Boundary Buses	Buses from which branches run into either a study system and one or more external systems, or into more than one external system.
Source System	A power system representation that contains all components of an external system as a subset of its own components. It is used to solve for the base conditions within the external system. The source system does not need to include the study system, but must recognize flows between the external and study system.
Electrical Equivalent	An artificial group of branches and buses that represents the behavior of the external system as seen from its boundary buses.
Retained Bus	A bus of the external system that is also a bus of the electrical equivalent. A retained bus is not necessarily a boundary bus, but all boundary buses are retained buses.
Deleted Bus	A bus of the external system that is not a bus of the electrical equivalent, but where the effect is represented by the equivalent.
Tie Branch	A branch with one end in one system (study or external) and the other end in a different system.
Area	A group of buses designated in power flow input data for interchange control purposes. An area may, but does not necessarily, coincide with a study or external system.

Chapter 9

Switching Studies

9.1. Examples

9.1.1. Fault Currents

Figure 9.1, "Switching Study for Balanced Three-Phase Operator (Sheet 1 of 6)" shows an example of calculations of fault currents in the substation represented by buses 1500 and 1550 in Figure 6.11, "Report from Activity BRCH after Modifying System for Transmission as Shown in Figure 6.10, "765-kV ac Transmission Option for Sample System"" in Chapter 6. The substation has two 765/345 kV transformers that must withstand three-phase solid faults on the 345-kV side, bus 1550. The example considers three situations.

1. The fault is on bus 1550 with all generation online at bus 1600 and all circuit breakers closed.

2. As in 1, but a circuit breaker has opened to remove one of the two 345/765-kV transformers from the system.

3. The fault is on bus 1550, with one generator off-line at bus 1600, its load being spread evenly on the other two units in the plant, and with all circuit breakers closed in the faulted substation.

Page 1 of the example shows recovery of the power flow case containing statuses in accordance with case 1, verification of generator source data, and solution for t^- voltages for case 1. This t^- solution is saved in saved case SCAC1.BASE *before* the application of CONG and CONL so that new t^- solutions can be derived from it. CONG and CONL are then used to set up the unswitched converted case, which is saved in SCAC1.CONV. The first fault situation is then set up immediately with CHNG and solved with ORDR, FACT, and TYSL. Using these activities together is the standard procedure for solving t^+ problems.

The results for case 1 are on the second page of the figure and show

$$\begin{aligned}\text{Fault current at bus} &= 12141 \text{ MVA} \\ &= 121.41 \text{ per unit} \\ &= \frac{12141 \times 10^6}{1.732 \times (345 \times 10^3)} \text{ A}\end{aligned}$$

The current contribution through one of the two 765/345-kV transformers, calculated at bus 1500 is

$$\frac{822.9}{100 + 0.2869} = 28.68 \text{ per unit}$$

or

$$\frac{822.9 \times 10^6}{1.732 \times (219.45 \times 10^3)} = 2170 \text{ A}$$

```
ACTIVITY? LIST
```

List to verify that generator ZSORCE values are correct

```
ENTER OUTPUT CATEGORY DESIRED:
 0 = TO EXIT                       1 = CASE SUMMARY
 2 = BUS DATA                      3 = SWITCHED SHUNT DATA
 4 = PLANT DATA                    5 = GEN. UNIT DATA
 6 = BRANCH DATA                   7 = BRANCH DATA
     (SINGLE ENTRY)                    (DOUBLE ENTRY)
 8 = TRANSFORMER DATA              9 = LINE SHUNT DATA
10 = DC LINE DATA                 11 = AREA INTERCHANGE DATA
12 = FULL LISTING                 13 = FULL LISTING
     (SINGLE ENTRY BRANCH)             (DOUBLE ENTRY BRANCH)
14 = IMPEDANCE CORRECTION DATA 15 = MULTI-SECTION LINE GROUPING DATA
16 = ZONE DATA: 5
```

Select generator data

```
     PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS®E      THU, OCT 03 1991  15:02
SAMPLE SYSTEM FOR PSS®E MANUAL                                     GENERATOR
765 KV AC CASE                                                     UNIT DATA
 BUS#    NAME   BSKV COD ID ST PGEN QGEN QMAX QMIN PMAX PMIN MBASE Z S O R C E     X T R A N    GENTAP
  100 NUCLEAR  345  2    1  1 1000  198  400 -100 1050  330 1100 0.0000 0.2000 0.0000 0.1500 1.0250
  100 NUCLEAR  345  2    2  1 1000  198  400 -100 1050  330 1100 0.0000 0.2000 0.0000 0.1500 1.0250
  200 HYDRO    345  2    1  1 1250  798 1000 -300 1750    0 1750 0.0000 0.2500 0.0000 0.1000 1.0250
 1100 CATNIP   230 -2    1  1  500  250  250    0  500  150  550 0.0000 0.2500 0.0000 0.1000 1.0250
 1401 WCOND   18.0 -2    1  1    0  400  400 -100 9999-9999  400 0.0000 0.1800
 1402 ECOND   18.0 -2    1  1    0  400  400 -100 9999-9999  800 0.0000 0.1800
 1600 MINE     765  3    1  1 1060  -92  667 -333 1610  320 1650 0.0000 0.2000 0.0000 0.1200 1.0250
 1600 MINE     765  3    2  1 1060  -92  667 -333 1610  320 1650 0.0000 0.2000 0.0000 0.1200 1.0250
 1600 MINE     765  3    3  1 1060  -92  667 -333 1610  320 1650 0.0000 0.2000 0.0000 0.1200 1.0250

ENTER 0 TO EXIT, 1 FOR NEW DATA CATEGORY: 0
```

Generator source data looks OK

```
ACTIVITY? FNSL
```

Solve power flow to establish t^- conditions

```
ENTER ITERATION NUMBER FOR VAR LIMITS
 0 FOR IMMEDIATELY, -1 TO IGNORE COMPLETELY:

ITER   DELTAP   BUS     DELTAQ   BUS      DELTA/V/   BUS    DELTAANG   BUS
 0    20.0000(  100)  18.0000( 1500)     0.08603( 1500)    0.86030( 1300)
 1     1.6809( 1501)   8.5468( 1400)     0.09672(  300)    0.12746(  800)
 2     1.5067(  100)   9.0662( 1401)     0.12660( 1100)    0.02111(  100)
 3     0.1654(  100)   0.6848( 1100)     0.00897( 1100)    0.00166(  100)
11     0.0008(  100)   0.0002( 1200)

REACHED TOLERANCE IN  11 ITERATIONS

LARGEST MISMATCH:    -0.08 MW    0.00 MVAR    0.08 MVA-BUS   100 [NUCLEAR  345]
SYSTEM TOTAL ABSOLUTE MISMATCH:               0.20 MVA

ACTIVITY? SAVE SCAC1.BASE
```

Save t^- condition for future reference

```
ACTIVITY? CONG
GENERATORS CONVERTED
```

Change to t^+ generator model

```
ACTIVITY? CONL ALL
```

Change load model to form suitable for t^+

```
ENTER % CONSTANT I, % CONSTANT G FOR REAL POWER: 50 50
ENTER % CONSTANT I, % CONSTANT B FOR REACTIVE POWER: 30 70

LOAD TO BE REPRESENTED AS:
   REAL   REACTIVE
  0.00%      0.00% CONSTANT POWER
 50.00%     30.00% CONSTANT CURRENT
 50.00%     70.00% CONSTANT ADMITTANCE
ENTER 1 IF O.K., 0 OTHERWISE: 1

LOADS CONVERTED AT      6 OF      6 LOAD BUSES

ACTIVITY? SAVE SCAC1.CONV
```

Figure 9.1. Switching Study for Balanced Three-Phase Operator (Sheet 1 of 6)

CHNG to apply fault

```
ACTIVITY? CHNG
ENTER CHANGE CODE:
 0 = EXIT ACTIVITY                   1 = BUS DATA
 2 = GENERATOR DATA                  3 = BRANCH DATA
 4 = TRANSFORMER DATA                5 = AREA INTERCHANGE DATA
 6 = TWO-TERMINAL DC LINE DATA       7 = SOLUTION PARAMETERS
 8 = CASE HEADING                    9 = SWITCHED SHUNT DATA
10 = IMPEDANCE CORRECTION TABLES  11 = MULTI-TERMINAL DC DATA
12 = ZONE DATA: 1
```

Fault is a bus data change

Fault at bus 1550

```
ENTER BUS NUMBER (0 FOR NEW CHANGE CODE, -1 TO EXIT): 1550
BUS DATA FOR BUS  1550 [MIDPNTL  345] :
  CODE    PLOAD    QLOAD       S H U N T     I L O A D     Y L O A D

OLD  1    0.00     0.00     0.00     0.00     0.0     0.0     0.0     0.0 CHANGE IT? 1
ENTER CODE, PLOAD, QLOAD, G, B, IP, IQ, YP, YQ
,,,,-2E9
NEW  1    0.00     0.00     0.00-0.2E+10     0.0     0.0     0.0     0.0
    AREA    VOLT    ANGLE    NAME    BASVLT LOSZON

OLD    4  1.0342  -15.66 MIDPNTL   345.0     1 CHANGE IT?
ENTER BUS NUMBER (0 FOR NEW CHANGE CODE, -1 TO EXIT): -1
```

Change it

Large inductive admittance serves as a solid three-phase fault

```
ACTIVITY? ORDR
DIAGONALS =    24  OFF-DIAGONALS =    44  MAX SIZE =    60
ACTIVITY? FACT
   24 DIAGONAL AND    44 OFF-DIAGONAL ELEMENTS
ACTIVITY? TYSL
ITER DELTAV/TOL  BUS    REAL(DELTAV)    IMAG(DELTAV)
   1 *********  1550    -0.9958E+00      0.2791E+00
   2 10286.095   500    -0.6265E-02      0.1027E+00
   3  1483.515   500     0.1725E-02     -0.1473E-01
   4   244.321   500    -0.9525E-03      0.2250E-02
   5    16.226   500     0.1601E-03      0.2664E-04
   6     8.449   500    -0.7041E-05     -0.8419E-04
   7     2.071   500    -0.3837E-05      0.2035E-04
   8     0.250   500     0.1229E-05     -0.2176E-05
REACHED TOLERANCE IN   8 ITERATIONS
```

ORDR, FACT, TYSL go together to solve at t^+

Power flow output serves well for balanced t^+ reporting

```
ACTIVITY? POUT
ENTER UP TO 20 BUS NUMBERS
1500 1550
     PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS®E      THU, OCT 03 1991  15:02
SAMPLE SYSTEM FOR PSS®E MANUAL                                         RATING
765 KV AC CASE                                                          SET A

BUS   1500 MIDPNT    765 AREA CKT     MW      MVAR      MVA   %I 0.2869PU -14.76 1500
                          1                                      219.45KV
 TO SHUNT                              0.0    148.1    148.1
 TO   1501 WCAP      765    1   1   -417.0   -618.3    745.8
 TO   1502 ECAP      765    1   1   -417.0   -618.3    745.8
 TO   1503 WCAPA     765    1   1    417.0   -278.6    501.5
 TO   1504 ECAPA     765    1   1    417.0   -278.6    501.5  78
 TO   1550 MIDPNTL   345    4   1      0.0    822.9    822.9 574
 TO   1550 MIDPNTL   345    4   2      0.0    822.9    822.9

BUS   1550 MIDPNTL   345 AREA CKT     MW      MVAR      MVA   %I 0.0000PU  -8.35 1550
                          4                                       0.002KV
 TO SHUNT                              0.0      0.1      0.1
 TO    100 NUCLEAR   345    1   1      0.0      0.0      0.0 381
 TO    100 NUCLEAR   345    1   2      0.0      0.0      0.0 381
 TO   1500 MIDPNT    765    1   1      0.0      0.0      0.0 574
 TO   1500 MIDPNT    765    1   2      0.0      0.0      0.0
 FAULT MVA                         -1763.1  12012.4  12141.1
ENTER UP TO 20 BUS NUMBERS
0
```

per-unit current contribution

$$= \frac{MVA}{SBASE \times v} = \frac{822.9}{100 \times 0.2869} = 28.68 \text{ per unit}$$

Fault MVA = 121.41 i.e., fault current = 121.41 per unit

Figure 9.2. Switching Study for Balanced Three-Phase Operator (Sheet 2 of 6)

```
ACTIVITY? CASE SCAC1.CONV
```

Recover converted case to calculate fault current for same t^- condition, different t^+ condition

```
SAMPLE SYSTEM FOR PSS®E MANUAL
765 KV AC CASE

CASE SCAC1.CONV WAS SAVED ON THU, OCT 03 1991  15:02

ACTIVITY? CHNG
```

CHNG to set t^+ condition

```
ENTER CHANGE CODE:
 0 = EXIT ACTIVITY                 1 = BUS DATA
 2 = GENERATOR DATA                3 = BRANCH DATA
 4 = TRANSFORMER DATA              5 = AREA INTERCHANGE DATA
 6 = TWO-TERMINAL DC LINE DATA     7 = SOLUTION PARAMETERS
 8 = CASE HEADING                  9 = SWITCHED SHUNT DATA
10 = IMPEDANCE CORRECTION TABLES  11 = MULTI-TERMINAL DC DATA
12 = ZONE DATA: 3

ENTER FROM BUS, TO BUS, CIRCUIT IDENTIFIER
 (FROM BUS = 0 FOR NEW CHANGE CODE, -1 TO EXIT): 1500 1550 1
```

Open 1 765/345 kV transformer

```
BRANCH DATA FOR CIRCUIT 1  FROM  1500 [MIDPNT   765] TO  1550 [MIDPNTL  345]:
 STATUS     LINE R     LINE X  CHARGING  RATE-A  RATE-B  RATE-C
OLD    1   0.00000    0.01000   0.00000   500.0   550.0   600.0 CHANGE IT? 1
ENTER STATUS, R, X, CHARGING, RATE-A, RATE-B, RATE-C, # OF CIRCUITS
0
NEW    0   0.00000    0.01000   0.00000   500.0   550.0   600.0
LINE SHUNTS: BUS  1500 [MIDPNT   765]  BUS  1550 [MIDPNTL  345]
OLD                   0.00000   0.00000          0.00000   0.00000 CHANGE IT?
METERED END IS BUS  1500 [MIDPNT   765]. ENTER 1 TO REVERSE:
ENTER FROM BUS, TO BUS, CIRCUIT IDENTIFIER
 (FROM BUS = 0 FOR NEW CHANGE CODE, -1 TO EXIT): 0

ENTER CHANGE CODE:
 0 = EXIT ACTIVITY                 1 = BUS DATA
 2 = GENERATOR DATA                3 = BRANCH DATA
 4 = TRANSFORMER DATA              5 = AREA INTERCHANGE DATA
 6 = TWO-TERMINAL DC LINE DATA     7 = SOLUTION PARAMETERS
 8 = CASE HEADING                  9 = SWITCHED SHUNT DATA
10 = IMPEDANCE CORRECTION TABLES  11 = MULTI-TERMINAL DC DATA
12 = ZONE DATA: 1
```

Apply three-phase fault at bus 1550, same as above

```
ENTER BUS NUMBER (0 FOR NEW CHANGE CODE, -1 TO EXIT): 1550
BUS DATA FOR BUS  1550 [MIDPNTL  345] :
  CODE    PLOAD    QLOAD       S H U N T      I L O A D      Y L O A D
OLD  1     0.00     0.00     0.00     0.00     0.0     0.0     0.0     0.0 CHANGE IT? 1
ENTER CODE, PLOAD, QLOAD, G, B, IP, IQ, YP, YQ
,,,,-2E9
NEW  1     0.00     0.00     0.00-0.2E+10     0.0     0.0     0.0     0.0
    AREA     VOLT    ANGLE    NAME    BASVLT LOSZON
OLD     4   1.0342  -15.66 MIDPNTL    345.0      1 CHANGE IT?
ENTER BUS NUMBER (0 FOR NEW CHANGE CODE, -1 TO EXIT): -1
ACTIVITY? ORDR
DIAGONALS =     24  OFF-DIAGONALS =     44  MAX SIZE =     60
ACTIVITY? FACT
   24 DIAGONAL AND    44 OFF-DIAGONAL ELEMENTS
ACTIVITY? TYSL
```

Standard t^+ solution procedure

```
ITER DELTAV/TOL  BUS    REAL(DELTAV)    IMAG(DELTAV)
   1 *********  1550    -0.9958E+00     0.2791E+00
   2  8751.300   500    -0.7177E-02     0.8722E-01
   3  1284.999   500    -0.1793E-03    -0.1285E-01
   8     0.444   500    -0.1341E-06     0.4441E-05

REACHED TOLERANCE IN   8 ITERATIONS
```

Figure 9.3. Switching Study for Balanced Three-Phase Operator (Sheet 3 of 6)

```
ACTIVITY? POUT

ENTER UP TO 20 BUS NUMBERS
1500 1550
     PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS®E      THU, OCT 03 1991  15:02
SAMPLE SYSTEM FOR PSS®E MANUAL                                      RATING
765 KV AC CASE                                                       SET A

BUS  1500 MIDPNT   765 AREA CKT     MW     MVAR     MVA  %I 0.4419PU -16.24 1500
                          1                                  338.09KV
 TO SHUNT                          0.0    351.6   351.6
 TO  1501 WCAP     765    1  1  -665.4  -802.8  1042.7
 TO  1502 ECAP     765    1  1  -665.4  -802.8  1042.7
 TO  1503 WCAPA    765    1  1   665.4  -349.6   751.7
 TO  1504 ECAPA    765    1  1   665.4  -349.6   751.7  76
 TO  1550 MIDPNTL  345    4  2     0.0  1953.1  1953.1
```

Current contribution in remaining transformer is now $\frac{1953.1}{100 \times 0.4419}$ ***= 44.2 per unit***

```
BUS  1550 MIDPNTL  345 AREA CKT     MW     MVAR     MVA  %I 0.0000PU  -8.47 1550
                          4                                   0.002KV
 TO SHUNT                          0.0     0.1      0.1
 TO   100 NUCLEAR  345    1  1     0.0     0.0      0.0 385
 TO   100 NUCLEAR  345    1  2     0.0     0.0      0.0 385
 TO  1500 MIDPNT   765    1  2     0.0     0.0      0.0
 FAULT MVA                     -1604.9 10777.7 10896.5
```

Fault MVA only slightly reduced

```
ENTER UP TO 20 BUS NUMBERS
0
ACTIVITY? CASE SCAC1.BASE
```

Recover unconverted base case to set up different t‾ condition.

```
SAMPLE SYSTEM FOR PSS®E MANUAL
765 KV AC CASE

CASE SCAC1.BASE WAS SAVED ON THU, OCT 03 1991  15:02

ACTIVITY? CHNG
ENTER CHANGE CODE:
 0 = EXIT ACTIVITY                  1 = BUS DATA
 2 = GENERATOR DATA                 3 = BRANCH DATA
 4 = TRANSFORMER DATA               5 = AREA INTERCHANGE DATA
 6 = TWO-TERMINAL DC LINE DATA      7 = SOLUTION PARAMETERS
 8 = CASE HEADING                   9 = SWITCHED SHUNT DATA
10 = IMPEDANCE CORRECTION TABLES   11 = MULTI-TERMINAL DC DATA
12 = ZONE DATA: 2

ENTER BUS NUMBER (0 FOR NEW CHANGE CODE, -1 TO EXIT): 1600
PLANT DATA FOR BUS  1600 [MINE      765] :
     VSCHED        REGULATED BUS   CODE  PERCENT VARS
OLD  1.0400       0 [MINE      765]   3      100.00 CHANGE IT?
ENTER MACHINE ID (CARRIAGE RETURN FOR NEXT MACHINE, -1 FOR NEXT BUS): 3
DATA FOR MACHINE 3 ON BUS  1600 [MINE      765] :
   STATUS    PGEN       QGEN      QMAX      QMIN      PMAX      PMIN
OLD  1    1060.29    -92.18    666.67   -333.33   1610.00    320.00 CHANGE IT? 1
ENTER STATUS, PGEN, QGEN, QMAX, QMIN, PMAX, PMIN: 0
NEW  0    1060.29    -92.18    666.67   -333.33   1610.00    320.00
```

Take 1 of 3 machines out out of service at bus 1600

```
       MBASE      Z S O R C E         X T R A N       GENTAP

OLD  1650.00  0.00000  0.20000  0.00000  0.12000  1.02500 CHANGE IT?

ENTER MACHINE ID (CARRIAGE RETURN FOR NEXT MACHINE, -1 FOR NEXT BUS): 2
DATA FOR MACHINE 2 ON BUS  1600 [MINE      765] :
   STATUS    PGEN       QGEN      QMAX      QMIN      PMAX      PMIN
OLD  1    1060.29    -92.18    666.67   -333.33   1610.00    320.00 CHANGE IT? 1
ENTER STATUS, PGEN, QGEN, QMAX, QMIN, PMAX, PMIN: ,1590
NEW  1    1590.00    -92.18    666.67   -333.33   1610.00    320.00
       MBASE      Z S O R C E         X T R A N       GENTAP
OLD  1650.00  0.00000  0.20000  0.00000  0.12000  1.02500 CHANGE IT?
```

Pick up load on machine 2

Figure 9.4. Switching Study for Balanced Three-Phase Operator (Sheet 4 of 6)

```
ENTER MACHINE ID (CARRIAGE RETURN FOR NEXT MACHINE, -1 FOR NEXT BUS): 1

DATA FOR MACHINE 1 ON BUS  1600 [MINE      765] :
  STATUS     PGEN       QGEN      QMAX      QMIN       PMAX       PMIN
OLD  1   1060.29    -92.18    666.67   -333.33   1610.00    320.00 CHANGE IT? 1
ENTER STATUS, PGEN, QGEN, QMAX, QMIN, PMAX, PMIN: ,1590
NEW  1   1590.00    -92.18    666.67   -333.33   1610.00    320.00

       MBASE      Z S O R C E         X T R A N      GENTAP
OLD  1650.00  0.00000  0.20000  0.00000  0.12000  1.02500 CHANGE IT?

ENTER MACHINE ID (CARRIAGE RETURN FOR NEXT MACHINE, -1 FOR NEXT BUS): -1

ENTER BUS NUMBER (0 FOR NEW CHANGE CODE, -1 TO EXIT): -1

ACTIVITY? FNSL

ENTER ITERATION NUMBER FOR VAR LIMITS
 0 FOR IMMEDIATELY, -1 TO IGNORE COMPLETELY: 0
ITER   DELTAP   BUS     DELTAQ   BUS      DELTA/V/   BUS    DELTAANG   BUS
  0     0.0008(  100)    0.0002( 1200)     0.00001( 1300)    0.00003(  500)
  1     0.0003(  100)    0.0002( 1201)

REACHED TOLERANCE IN    1 ITERATIONS

LARGEST MISMATCH:     0.00 MW   -0.07 MVAR     0.07 MVA-BUS  1201 [SWIGA    230]
SYSTEM TOTAL ABSOLUTE MISMATCH:                0.14 MVA

ACTIVITY? GEOL ALL

ENTER 1 FOR OVERLOADED MACHINES ONLY   2 FOR ALL: 2
     PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS®E      THU, OCT 03 1991   15:02
SAMPLE SYSTEM FOR PSS®E MANUAL
765 KV AC CASE

MACHINE SUMMARY:
  BUS    NAME BSVLT ID     MW     MVAR  ETERM CURRENT    PF   MVABASE   X T R A N   GENTAP
  100 NUCLEAR   345 1  1000.0    335.5 1.0499  1004.7  0.9481  1100.0 0.0000 0.1500 1.0250
  100 NUCLEAR   345 2  1000.0    335.5 1.0499  1004.7  0.9481  1100.0 0.0000 0.1500 1.0250
  200 HYDRO     345 1  1250.0    919.7 1.0619  1461.4  0.8055  1750.0 0.0000 0.1000 1.0250
 1100 CATNIP    230 1   500.0    299.3 1.1193   520.6  0.8580   550.0 0.0000 0.1000 1.0250
 1401 WCOND    18.0 1     0.0    400.0 0.9898   404.1* 0.0000   400.0
 1402 ECOND    18.0 1     0.0    400.0 0.9898   404.1  0.0000   800.0
 1600 MINE      765 1  1272.5      4.6 1.0108  1258.9  1.0000  1650.0 0.0000 0.1200 1.0250
 1600 MINE      765 2  1908.2     93.2 1.0120  1887.8* 0.9988  1650.0 0.0000 0.1200 1.0250
SUBSYSTEM TOTALS       6930.7  2787.8                          9000.0

ACTIVITY? CONG

GENERATORS CONVERTED

ACTIVITY? CONL ALL
ENTER % CONSTANT I, % CONSTANT G FOR REAL POWER: 50 50
ENTER % CONSTANT I, % CONSTANT B FOR REACTIVE POWER: 30 70

LOAD TO BE REPRESENTED AS:
   REAL   REACTIVE
  0.00%      0.00% CONSTANT POWER
 50.00%     30.00% CONSTANT CURRENT
 50.00%     70.00% CONSTANT ADMITTANCE
ENTER 1 IF O.K., 0 OTHERWISE: 1

LOADS CONVERTED AT      6 OF      6 LOAD BUSES
```

Pick up load on machine 1

Resolve to ensure proper t⁻ set-up

Check new loading; GEOL is a convenient way to do this

Prepare converted case as before

Figure 9.5. Switching Study for Balanced Three-Phase Operator (Sheet 5 of 6)

```
ACTIVITY? CHNG

ENTER CHANGE CODE:
 0 = EXIT ACTIVITY                  1 = BUS DATA
 2 = GENERATOR DATA                 3 = BRANCH DATA
 4 = TRANSFORMER DATA               5 = AREA INTERCHANGE DATA
 6 = TWO-TERMINAL DC LINE DATA      7 = SOLUTION PARAMETERS
 8 = CASE HEADING                   9 = SWITCHED SHUNT DATA
10 = IMPEDANCE CORRECTION TABLES   11 = MULTI-TERMINAL DC DATA
12 = ZONE DATA: 1

ENTER BUS NUMBER (0 FOR NEW CHANGE CODE, -1 TO EXIT): 1550

BUS DATA FOR BUS  1550 [MIDPNTL  345] :
  CODE   PLOAD   QLOAD      S H U N T      I L O A D      Y L O A D
OLD  1   0.00    0.00    0.00    0.00    0.0    0.0    0.0    0.0 CHANGE IT? 1
ENTER CODE, PLOAD, QLOAD, G, B, IP, IQ, YP, YQ
,,,,-2E9
NEW  1    0.00    0.00    0.00-0.2E+10    0.0    0.0    0.0    0.0

    AREA    VOLT   ANGLE   NAME   BASVLT LOSZON

OLD    4  1.0342  -15.66 MIDPNTL   345.0     1 CHANGE IT?

ENTER BUS NUMBER (0 FOR NEW CHANGE CODE, -1 TO EXIT): -1
```

Apply three-phase fault at bus 1550 as before

```
ACTIVITY? ORDR
DIAGONALS =    24  OFF-DIAGONALS =    44  MAX SIZE =    60

ACTIVITY? FACT
   24 DIAGONAL AND    44 OFF-DIAGONAL ELEMENTS

ACTIVITY? TYSL
```

Standard t^{+} solution procedure

```
ITER DELTAV/TOL  BUS    REAL(DELTAV)    IMAG(DELTAV)
   1 *********  1550    -0.9958E+00      0.2791E+00
   2 10657.266   500    -0.5872E-02      0.1064E+00
   3  1560.657   500     0.2545E-02     -0.1540E-01
   8     0.268   500     0.2645E-05     -0.4470E-06

REACHED TOLERANCE IN   8 ITERATIONS

ACTIVITY? POUT
ENTER UP TO 20 BUS NUMBERS
1500 1550
     PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS®E      THU, OCT 03 1991  15:02
SAMPLE SYSTEM FOR PSS®E MANUAL                                       RATING
765 KV AC CASE                                                        SET A

BUS  1500 MIDPNT   765 AREA CKT    MW      MVAR     MVA   %I 0.2596PU -14.52 1500
                         1                                   198.62KV
 TO SHUNT                          0.0    121.3    121.3
 TO  1501 WCAP     765    1   1  -374.6  -474.1    604.2
 TO  1502 ECAP     765    1   1  -374.6  -474.1    604.2
 TO  1503 WCAPA    765    1   1   374.6  -260.6    456.3
 TO  1504 ECAPA    765    1   1   374.6  -260.6    456.3  78
 TO  1550 MIDPNTL  345    4   1     0.0   674.1    674.1  519
 TO  1550 MIDPNTL  345    4   2     0.0   674.1   [674.1]

BUS  1550 MIDPNTL  345 AREA CKT    MW      MVAR     MVA   %I 0.0000PU  -7.89 1550
                         4                                    0.002KV
 TO SHUNT                          0.0      0.1      0.1
 TO   100 NUCLEAR  345    1   1     0.0      0.0      0.0 380
 TO   100 NUCLEAR  345    1   2     0.0      0.0      0.0 380
 TO  1500 MIDPNT   765    1   1     0.0      0.0      0.0 519
 TO  1500 MIDPNT   765    1   2     0.0      0.0      0.0
 FAULT MVA                      -1591.5 11479.5 11589.3
ENTER UP TO 20 BUS NUMBERS
0
```

Transformer fault current

$$= \frac{674.1}{100 \times 0.2596} = 25.97 \text{ per unit}$$

Little change in fault MVA

Figure 9.6. Switching Study for Balanced Three-Phase Operator (Sheet 6 of 6)

The fault current on the 345 kV side, at bus 1550 is 28.68 per unit, of course, but is given in amperes by

$$2170 \times \frac{765}{345} = 4811.7\ \text{A}$$

The second case of the example pertains to the same initial condition, but seeks the currents that would exist if the circuit breaker feeding one of the transformers should be the first to open. Because it applies to the same t^- conditions as already established, this calculation is started by recovering the converted saved case, SCAC1.CONV. All that is needed to set up the t^+ solution is to open a transformer and apply the fault with CHNG. The results, on the fourth page of Figure 9.4, “Switching Study for Balanced Three-Phase Operator (Sheet 4 of 6)”, show that the opening of one transformer raises the fault current flowing through the other to

$$\frac{1953.1}{100 \times 0.4419} = 44.2 \text{ per unit}$$

or

$$\frac{1953.1 \times 10^6}{1.732 \times (338.09 \times 10^3)} = 3335\ \text{A}$$

while the total fault MVA is reduced from 12141 to 10897.

The third calculation of the example cannot be started from the converted saved case because it pertains to a different t^- condition and requires a new power flow solution to be made *before* the application of activities CONG and CONL. This calculation is started by recovering the base case, SCAC1.BASE, rearranging plant conditions at bus 1600, and resolving the power flow for the new t^- conditions. The results on the last page of Figure 9.1, “Switching Study for Balanced Three-Phase Operator (Sheet 1 of 6)” show a very much expected reduction of the fault current in the single transformer to somewhat less than 2/3 of its value in the second case. The per-unit value is

$$\frac{674.1}{100 \times 0.2596} = 25.97 \text{ per unit}$$

9.1.2. Voltage Rise on Line Opening

A switching study does not have to consider a short-circuit fault. The example shown in Figure 9.7, “Switching Study to Calculate Voltage Rise on Open End of 765-kV Line” calculates the voltage rise at the end of a long 765-kV transmission line when the circuit breaker is opened at one end. The example applies to the 765-kV AC system shown in Figure 6-48. The required result is the voltage that would occur at bus 1504 and across the circuit breaker, if the circuit breaker at bus 1500 in the capacitor branch 1500-1504 should be opened, with no other event occurring. Because no current will flow in the capacitor after the breaker opens, the voltage across the capacitor will equal the difference between the t^+ voltages at buses 1500 and 1504.

Recover solved case for t^-

```
ACTIVITY? CASE SCAC1.BASE
SAMPLE SYSTEM FOR PSS®E MANUAL
765KV DC CASE

CASE SCAC1.BASE WAS SAVED ON THU, OCT 03 1991   13:25
```

Convert generators to set up t^+ solution

```
ACTIVITY? CONG
GENERATORS CONVERTED
ACTIVITY? CHNG

ENTER CHANGE CODE:
 0 = EXIT ACTIVITY                  1 = BUS DATA
 2 = GENERATOR DATA                 3 = BRANCH DATA
 4 = TRANSFORMER DATA               5 = AREA INTERCHANGE DATA
 6 = TWO-TERMINAL DC LINE DATA      7 = SOLUTION PARAMETERS
 8 = CASE HEADING                   9 = SWITCHED SHUNT DATA
10 = IMPEDANCE CORRECTION TABLES   11 = MULTI-TERMINAL DC DATA
12 = ZONE DATA: 3
```

Open branch 1500-1504 to simulate opening of breaker at bus 1500 end

```
ENTER FROM BUS, TO BUS, CIRCUIT IDENTIFIER
 (FROM BUS = 0 FOR NEW CHANGE CODE, -1 TO EXIT): 1500 1504
BRANCH DATA FOR CIRCUIT 1  FROM  1500 [            ] TO  1504 [ECAPA    765]:
 STATUS    LINE R    LINE X   CHARGING  RATE-A  RATE-B  RATE-C
OLD   1   0.00000  -0.00690   0.00000  2250.0  2250.0  2250.0 CHANGE IT? 1
ENTER STATUS, R, X, CHARGING, RATE-A, RATE-B, RATE-C, # OF CIRCUITS
0
NEW   0   0.00000  -0.00690   0.00000  2250.0  2250.0  2250.0
LINE SHUNTS: BUS  1500 [            ]  BUS  1504 [ECAPA    765]
OLD                0.00000   0.00000           0.00000   0.00000 CHANGE IT?
METERED END IS BUS  1500 [            ]. ENTER 1 TO REVERSE:
ENTER FROM BUS, TO BUS, CIRCUIT IDENTIFIER
 (FROM BUS = 0 FOR NEW CHANGE CODE, -1 TO EXIT): -1
```

Standard t^+ solution procedure

```
ACTIVITY? ORDR
DIAGONALS =    24  OFF-DIAGONALS =    44  MAX SIZE =    60
ACTIVITY? FACT
   24 DIAGONAL AND    43 OFF-DIAGONAL ELEMENTS

ACTIVITY? TYSL
   1 67267.008  1504    -0.1446E+00    -0.6569E+00
   2  8004.175  1300     0.1620E-01     0.7838E-01
  20   220.205   500     0.3960E-03     0.2166E-02
TERMINATED AFTER  20 ITERATIONS
```

Convergence is slow

Keep going

```
ACTIVITY? TYSL
   1   181.736   500    -0.5531E-03    -0.1731E-02
   2   150.050   500     0.2698E-03     0.1476E-02
  20     4.834   500     0.8643E-05     0.4756E-04
TERMINATED AFTER  20 ITERATIONS
```

Not yet converged

Keep going

```
ACTIVITY? TYSL
   1     3.996   500    -0.1228E-04    -0.3803E-04
   2     3.289   500     0.5841E-05     0.3237E-04
   9     0.850   500    -0.2563E-05    -0.8106E-05
REACHED TOLERANCE IN   9 ITERATIONS
```

Converged

```
ACTIVITY? VCHK
ENTER VMAX, VMIN:

     PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS®E      THU, OCT 03 1991   13:32
SAMPLE SYSTEM FOR PSS®E MANUAL
765KV DC CASE

BUSES WITH VOLTAGE GREATER THAN 1.0500:
X------ BUS -----X AREA V(PU)  V(KV)     X------ BUS -----X AREA V(PU)  V(KV)
 1100 CATNIP    230    2 1.1081 254.87     1504 ECAPA     765    1 1.1712 895.93

BUSES WITH VOLTAGE LESS THAN 0.9500:
X------ BUS -----X AREA V(PU)  V(KV)     X------ BUS -----X AREA V(PU)  V(KV)
  300 WEST      345    1 0.8672 299.19      400 EAST      345    1 0.8876 306.22
  500 WESTLV    230    2 0.9444 217.22
```

Fairly serious voltage rise

Figure 9.7. Switching Study to Calculate Voltage Rise on Open End of 765-kV Line

The dialog in Figure 9.7, “Switching Study to Calculate Voltage Rise on Open End of 765-kV Line” shows recovery of the saved case SCAC1.BASE, which contains the t^-solution, followed by use of activity CONG. Activity CONL is not used in this calculation because overvoltages, rather than undervoltages, are expected and the conventional assumption of a constant MVA load characteristic is judged to be reasonable. The solution by TYSL converges slowly, but does reach its tolerance after 31 iterations. The postswitching voltages are displayed by activity VCHK. There is little voltage change at any of the load buses, justifying the retention of the constant MVA load treatment, but a rise to 1.17 per unit at the open line end due to the Ferranti effect.

The voltage difference across the circuit breaker requires the use of activity POUT to show phase angle, as well as amplitude, of the voltages at buses 1500 and 1504. POUT shows that the t^+ voltages are

v_{1500} = 1.023 at –13.69°

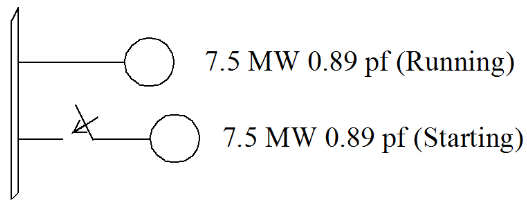
v_{1504} = 1.171 at –43.41°

The difference is 0.148 per unit at 29.7°. It is clear that it is the phase difference created by opening the circuit breaker, rather than the voltage rise on the open line end, that makes the major contribution to the voltage across its contacts.

9.1.3. Motor Starting

A fairly common switching study requirement is illustrated by Figure 9.8, “Calculation of Voltage Dip Produced by Switching Motor Directly onto Bus at Standstill”. One of a pair of large motors is running under load, and the second one is to be started by switching it directly onto the bus. The extent of the voltage dip produced by switching on the second motor is needed for the coordination of overcurrent and undervoltage protection.

Figure 9.9, “Switching Study to Calculate Voltage Dip on Starting of Large Induction Motor (Sheet 1 of 3)” shows an example calculation of such a voltage dip for the small system shown in Figure 13-1. The load at bus 151 is assumed to consist of two large motors that, at full load and unity voltage, draw (7.5 + j3.95) MVA each. The starting current for one motor is given in specification data as 2.72 times rated current at 0.275 power factor. The calculation in Figure 9.8, “Calculation of Voltage Dip Produced by Switching Motor Directly onto Bus at Standstill” shows that this starting duty corresponds to an initial shunt admittance of (0.0625 - j0.218) per unit, relative to a 100-MVA base.



Starting current = 2.72 × rated at 0.275 pf

Starting admittance

$$= 2.72 \times \frac{0.075}{0.89}(\cos\phi_s - j\sin\phi_s)$$

$$= 0.227(0.275 - j0.961)$$

$$= 0.0625 - j0.218$$

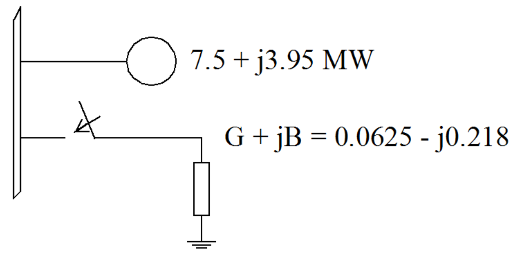


Figure 9.8. Calculation of Voltage Dip Produced by Switching Motor Directly onto Bus at Standstill

```
     PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS®E      FRI, OCT 04 1991  11:01
SMALL EXAMPLE SYSTEM                                                  BUS DATA
BOONDOCKS POWER AND LIGHT
 BUS#    NAME   BSKV CODE    VOLT  ANGLE    PLOAD    QLOAD      S H U N T  AREA ZONE
  100 HYDRO    33.0    3  1.0500    0.0      0.0      0.0     0.0      0.0     1    1
  150 LOAD     33.0    1  1.0000    0.0      5.0      1.6     0.0      0.0     2    1
  151 LOAD     3.30    1  1.0000    0.0     15.0      7.9     0.0      0.0     2    1
  200 STEAM    33.0    1  1.0000    0.0      0.0      0.0     0.0      0.0     1    1
  201 STEAM    3.30    2  1.0000    0.0      0.0      0.0     0.0      0.0     1    1
```

This load represents 2 motors - take 1 off and solve for new initial condition

```
ACTIVITY? CHNG

ENTER CHANGE CODE:
 0 = EXIT ACTIVITY                  1 = BUS DATA
 2 = GENERATOR DATA                 3 = BRANCH DATA
 4 = TRANSFORMER DATA               5 = AREA INTERCHANGE DATA
 6 = TWO-TERMINAL DC LINE DATA      7 = SOLUTION PARAMETERS
 8 = CASE HEADING                   9 = SWITCHED SHUNT DATA
10 = IMPEDANCE CORRECTION TABLES   11 = MULTI-TERMINAL DC DATA
12 = ZONE DATA: 1

ENTER BUS NUMBER (0 FOR NEW CHANGE CODE, -1 TO EXIT): 151

BUS DATA FOR BUS   151 [LOAD    3.30] :
  CODE     PLOAD     QLOAD        S H U N T
OLD  1     15.00      7.90      0.00      0.00 CHANGE IT? 1
ENTER CODE, PLOAD, QLOAD, G, B
,7.5 3.85
NEW  1      7.50      3.85      0.00      0.00
    AREA     VOLT    ANGLE    NAME    BASVLT LOSZON
OLD    2  1.0000     0.00 LOAD         3.3      1 CHANGE IT?
ENTER BUS NUMBER (0 FOR NEW CHANGE CODE, -1 TO EXIT): -1
```

Change bus load to represent 1 of 2 motors

```
ACTIVITY? FNSL
ORDERING NETWORK
DIAGONALS =      4  OFF-DIAGONALS =      3  MAX SIZE =      6

ENTER ITERATION NUMBER FOR VAR LIMITS
 0 FOR IMMEDIATELY, -1 TO IGNORE COMPLETELY:

ITER    DELTAP    BUS      DELTAQ    BUS      DELTA/V/    BUS   DELTAANG    BUS
  0     0.0800(  201)     0.5768(  150)     0.20518(  201)    0.06929(  201)
  1     0.0222(  200)     0.2333(  201)     0.39825(  201)    0.01389(  201)
  2     0.0053(  200)     0.1468(  201)     0.08667(  201)    0.00849(  201)
  3     0.0010(  200)     0.0259(  200)     0.01614(  201)    0.00174(  201)
  4     0.0000(  200)     0.0003(  201)
REACHED TOLERANCE IN   4 ITERATIONS

LARGEST MISMATCH:     0.00 MW     0.03 MVAR     0.03 MVA-BUS    201 [STEAM   3.30]
SYSTEM TOTAL ABSOLUTE MISMATCH:                 0.04 MVA
```

Solve for t^- conditions

```
ACTIVITY? POUT
ENTER UP TO 20 BUS NUMBERS
151
     PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS®E      FRI, OCT 04 1991  11:01
SMALL EXAMPLE SYSTEM                                                    RATING
BOONDOCKS POWER AND LIGHT                                                SET A

BUS    151 LOAD     3.30 AREA CKT     MW      MVAR      MVA   %I 1.0106PU  -1.52   151
                           2                                      3.335KV
 TO LOAD-PQ                          7.5       3.8      8.4
 TO    150 LOAD     33.0    2  1    -7.5      -3.9      8.4   56 1.0250UN
ENTER UP TO 20 BUS NUMBERS
0
```

Print t^- conditions at motor bus

Voltage at t^-, just before motor start

Figure 9.9. Switching Study to Calculate Voltage Dip on Starting of Large Induction Motor (Sheet 1 of 3)

```
ACTIVITY? CONG
```

Convert generators for t^+ modeling

```
GENERATORS CONVERTED

ACTIVITY? CONL ALL

ENTER % CONSTANT I, % CONSTANT G FOR REAL POWER: 50 50

ENTER % CONSTANT I, % CONSTANT B FOR REACTIVE POWER: 30 70
```

Convert loads to a reasonable assumption on voltage characteristics for voltages in 0.7 to 1.0 per-unit range

```
LOAD TO BE REPRESENTED AS:
   REAL   REACTIVE
  0.00%      0.00% CONSTANT POWER
 50.00%     30.00% CONSTANT CURRENT
 50.00%     70.00% CONSTANT ADMITTANCE

ENTER 1 IF O.K., 0 OTHERWISE: 1
```

Believable for now!

```
LOADS CONVERTED AT      2 OF      2 LOAD BUSES

ACTIVITY? ORDR
DIAGONALS =      5  OFF-DIAGONALS =      5  MAX SIZE =     10

ACTIVITY? FACT
    5 DIAGONAL AND      5 OFF-DIAGONAL ELEMENTS

ACTIVITY? TYSL
```

Solve at t^+ with no switching. Should refine solution but make no substantial change

```
ITER DELTAV/TOL  BUS    REAL(DELTAV)  IMAG(DELTAV)
   1     44.108  201     -0.4411E-03     0.2734E-05
   2      0.102  151     -0.9537E-06     0.3502E-06

REACHED TOLERANCE IN   2 ITERATIONS
```

These are very small changes - TYSL uses a very tight convergence tolerance

Figure 9.10. Switching Study to Calculate Voltage Dip on Starting of Large Induction Motor (Sheet 2 of 3)

Apply switching operation, motor switch-on in this case

```
ACTIVITY? CHNG
ENTER CHANGE CODE:
 0 = EXIT ACTIVITY                    1 = BUS DATA
 2 = GENERATOR DATA                   3 = BRANCH DATA
 4 = TRANSFORMER DATA                 5 = AREA INTERCHANGE DATA
 6 = TWO-TERMINAL DC LINE DATA        7 = SOLUTION PARAMETERS
 8 = CASE HEADING                     9 = SWITCHED SHUNT DATA
10 = IMPEDANCE CORRECTION TABLES     11 = MULTI-TERMINAL DC DATA
12 = ZONE DATA: 1

ENTER BUS NUMBER (0 FOR NEW CHANGE CODE, -1 TO EXIT): 151
```

Switch motor on bus 151

```
BUS DATA FOR BUS    151 [LOAD     3.30] :
   CODE    PLOAD    QLOAD       S H U N T      I L O A D     Y L O A D
OLD  1     0.00     0.00     0.00     0.00     3.7      1.1     3.7   -2.6 CHANGE IT? 1
ENTER CODE, PLOAD, QLOAD, G, B, IP, IQ, YP, YQ
,,,6.25 -21.8
NEW  1     0.00     0.00     6.25  -21.80      3.7      1.1     3.7   -2.6
     AREA     VOLT    ANGLE    NAME     BASVLT LOSZON
OLD     2  1.0103    -1.52 LOAD          3.3      1 CHANGE IT?
ENTER BUS NUMBER (0 FOR NEW CHANGE CODE, -1 TO EXIT): -1
```

Represent motor as G + jB = .0625 - j.218

```
ACTIVITY? ORDR
DIAGONALS =      5   OFF-DIAGONALS =       5   MAX SIZE =     10
ACTIVITY? FACT
    5 DIAGONAL AND      5 OFF-DIAGONAL ELEMENTS

ACTIVITY? TYSL
   1 27610.336    151     -0.2744E+00     -0.3058E-01
   2   317.038    151     -0.2843E-02      0.1404E-02
   3    11.002    151      0.9811E-04     -0.4980E-04
   4     0.400    151     -0.3576E-05      0.1796E-05
REACHED TOLERANCE IN   4 ITERATIONS
```

Standard t^+ solution procedure

```
ACTIVITY? VCHK
ENTER VMAX, VMIN:
     PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS®E      FRI, OCT 04 1991   11:01
SMALL EXAMPLE SYSTEM
BOONDOCKS POWER AND LIGHT

BUSES WITH VOLTAGE GREATER THAN 1.0500:

X------ BUS -----X AREA V(PU)  V(KV)    X------ BUS -----X AREA V(PU)  V(KV)

                                  * NONE *

BUSES WITH VOLTAGE LESS THAN 0.9500:

X------ BUS -----X AREA V(PU)  V(KV)    X------ BUS -----X AREA V(PU)  V(KV)
  100 HYDRO    33.0    1 0.8233 27.168    150 LOAD     33.0    2 0.8128 26.821
  151 LOAD     3.30    2 0.7349  2.425    200 STEAM    33.0    1 0.8226 27.145
  201 STEAM    3.30    1 0.8426  2.780
```

Use VCHK to look for voltages below normal

Voltage dips to 73% at motor base.

```
ACTIVITY? POUT
ENTER UP TO 20 BUS NUMBERS
151
     PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS®E      FRI, OCT 04 1991   11:01
SMALL EXAMPLE SYSTEM                                                  RATING
BOONDOCKS POWER AND LIGHT                                              SET A
BUS    151 LOAD     3.30 AREA CKT     MW      MVAR      MVA   %I 0.7349PU  -4.37  151
                           2                                       2.425KV
 TO LOAD-I                           2.7       0.8       2.9
 TO LOAD-Y                           2.0       1.4       2.4
 TO SHUNT                            3.4      11.8      12.2
 TO    150 LOAD     33.0    2   1   -8.1     -14.0      16.2 147 1.0250UN
ENTER UP TO 20 BUS NUMBERS
0
```

Quick check on motor bus.

This is the t^- load, as converted and the reduced voltage

Motor starting inrush is 12.2 MVA at 73% voltage

Figure 9.11. Switching Study to Calculate Voltage Dip on Starting of Large Induction Motor (Sheet 3 of 3)

The dialog shown in Figure 9.9, “Switching Study to Calculate Voltage Dip on Starting of Large Induction Motor (Sheet 1 of 3)” sets up the t^- power flow condition in which one motor is running, converts generators and loads to establish a t^+ model, and solves for t^+ conditions both without and with the motor standstill admittance. The first page of Figure 9.9, "Switching Study to Calculate Voltage Dip on Starting of Large Induction Motor (Sheet 1 of 3)" shows the setup of the t^{-} power flow solution. The second page shows dialog to establish a voltage-dependent load characteristic for the system load other than the incoming motor. CONL is instructed to represent all initial loads by a mixture of components with constant current and constant admittance characteristics. The second page also shows the use of ORDR, FACT, and TYSL to solve the system at time t^{+} with no disturbance switched on. This serves to refine the voltage vector and confirm that the t^{-} solution is held without change at t^{+} if no change is made in the system boundary conditions. Any substantial change in the voltage estimates during such a precautionary execution of TYSL indicates that the working case was not solved to an adequate tolerance prior to the execution of CONG and CONL.

The third page of Figure 9.11, "Switching Study to Calculate Voltage Dip on Starting of Large Induction Motor (Sheet 3 of 3)" shows the use of CHNG to apply the motor standstill admittance to bus 151, the new solution for t^{+} voltages, and output of results with activities VCHK and POUT. The starting of the motor in this case pulls the voltage at its terminals down to 0.73 per unit, and pulls voltages throughout the small system to below 90%.

The current drawn by the motor that was initially online could be estimated (assuming the user accepts the load characteristic set up by CONL as a reasonable representation) as

$$\frac{(0.027 - j0.008)}{0.7349} + \frac{(0.02 - j0.014)}{0.7349^2} = 0.0738 - j0.0368$$

$$= 0.0825 \text{ per unit}$$

which is less than the motor's rated current of (0.075/0.9) = 0.0833 per unit.

9.2. IEC Data File Contents

The impedances and admittances of electrical equipment in the working case are modified according to the correction factors defined in IEC 60909-0, Section 3.

Generators, equivalent generators and asynchronous motors are represented as sources in the working case. To calculate their impedance correction factors additional data is required. This additional data is provided in IEC data file (.iec).

Additional data is needed in the following cases:

- If a generator model includes a GSU transformer. It is recommended to represent the GSU transformer explicitly as a separate power component so as to be able to correctly modify the generator and transformer impedances as per the IEC 60909 standard.
- If a generator in the working case is an equivalent generator representation.
- If a generator is a used in the modeling of a synchronous motor.
- If a generator is set with QMIN=QMAX, then it is treated as an asynchronous motor. If this is the case, then additional data is not necessary.
- If a transformer winding MVA specified in system MVA base and not nameplate winding MVA.

If an induction machine base power (MBASE) is specified as mechanical power output (BCODE=1), then power factor and efficiency are needed to calculate base MVA. If an induction machine scheduled active power (PSET) is set as real electrical power drawn by the machine, efficiency is needed to calculate mechanical power output (MW) of the machine.

There are three groups of records, with each group containing a particular type of data required. Each record is terminated by specifying a bus number of 0.

9.2.1. GSU, Equivalent Generator and Induction Machine Data

Induction Motors are specified as part of Generator data category.

Each data record has the following format:

```
I, ID, MCTYPE, UrG, PG, PFactor, PolePair, GSUType, Ix, Jx, Kx, Ckt, PT
```

where:

I Machine bus number

ID Machine ID

MCTYPE Machine type

MCTYPE =1, for Generator

MCTYPE =2, for Equivalent generator

MCTYPE =3, for Induction machines specified as part of generator data category

UrG Rated terminal voltage, line-to-line in kV r.m.s. (this need not be the rated bus

voltage)

PG Range of generator voltage regulation in %, e.g., if PG is ±5%, enter PG=5.

PG = (UG -UrG)/UrG, where UG is the scheduled generator terminal

voltage = 0 default

PFactor Generator rated power factor (used only if MCTYPE=1).

This is used in impedance correction factor calculations.

= 1.0 default

PolePair Number of pole pairs if machine is induction machine (used only if the

machine is modeled as induction machine)

Example: If the induction machine has a six pole construction then

Polepair=3

GSUType Generator step-up-transformer type

GSUType =0, no GSU, GSU transformer modeled explicitly.

GSUType =1, GSU with OLTC

GSUType =2, GSU without OLTC

Ix GSU transformer I bus number

Jx GSU transformer J bus number

Kx GSU transformer K bus number

Ckt GSU transformer circuit identifier

PT Tap range of GSU off-load tap-changer transformer in % of transformer winding

rated voltage, e.g., if PT is ±5%, enter PT=5

9.3. Induction Machine Data

Induction Motors are specified as part of Induction machine data category

Each data record has the following format:

```
I, ID, PolePair, PFactor, Efficiency
```

where:

I Machine bus number

ID Machine ID

PolePair Number of pole pairs

Example: If the induction machine has a six pole construction then Polepair=3

PFactor Induction Machine rated power factor

= 1.0 default

Efficiency Induction Machine percent efficiency.

=100 by default

Example: Efficiency=96.5 for 96.5% efficiency.

Data records for generating units and motors may be entered in any order and using a free format with blanks or commas separating each data item in each record. These records are terminated with a record specifying machine bus number I value of zero. Following is an example of IEC data for IEC 60909-4, Section 6 network. (Refer to PAG for details.)

```
1 Q1 2

5 Q2 2

6 G3 1 10.5 0.0 0.8

41 G1 1 21.0 0.0 0.85 0 1 4 41 0 T1 12

31 G2 1 10.5 7.5 0.9 0 2 3 31 0 T2

0 / END OF GSU, EQV, GEN, AND INDUCTION MACHINE DATA

0 / END OF TRANSFORMER DATA

7 M1 1 0.88 97.5

7 M2 2 0.89 96.8

7 M3 2 0.89 96.8

0 / END OF INDUCTION MACHINE DATA
```

9.4. Objective

The objective of a switching study is to calculate the conditions that will exist in the power system just after a sudden change such as the opening of a transmission line, switching on of a large load, application of a fault, or tripping of a generator. These calculations are useful, for example:

1. To show the immediate voltage dip caused by switching on of a large motor.
2. To give symmetrical fault duty at a bus.
3. To show the immediate change of flow that will be seen on each tie-line into an area (before the inertial swing of rotor angles) when one such tie or a generator within the area is tripped.

In the terms of Section 5.6, “Dynamic Boundary Conditions” and Figure 5.7, “Time Regimes Considered in Power System Simulations”, a switching study is a calculation of conditions at time, t^+. A switching study is, in effect, the calculation of the transmission system conditions at the first instant, $t = t^+$, of a dynamic simulation, separated from the subsequent calculation of conditions at later instants, $t > t^+$. Switching study results are presented and examined with the same output and limit checking activities as are used in power flow work.

9.5. Setup and Initialization

9.5.1. Base Power Flow

The starting point for a switching study is a conventional solved power flow case giving data and solution corresponding to the pre-switching (t^{-}) condition. Conventional procedures, as covered in Chapter 6, *Basic Power Flow Activity Applications*, are used with the proviso that the dynamic impedance, ZSORCE, must be included in the database for *every* generator, and step-up transformer data, XTRAN and GENTAP, must be present for all generators where the implicit step-up transformer treatment is used.

The generator dynamic impedance and step-up transformer parameters are not needed during power flow solutions; they may be added to the working case with activity MCRE after extensive power flow work has been completed. A solved power flow case need not be resolved after any item of generator dynamic impedance or step-up transformer is added or changed because the dynamic impedance and step-up transformer parameters affect only the Norton equivalent current sources, ISORCE, that will represent the generators in the post-switching calculation.

9.5.2. Boundary Conditions

Generators - Activity CONG

Power flow studies use a generator boundary condition reflecting the normal operating practice of making gentle turbine power and excitation adjustments to produce a desired value of power flow and voltage at the generator bus. Switching studies, in contrast, pertain to conditions immediately after a sudden change of system conditions and must use a generator boundary condition based on the inherent physical characteristics of the generator rather than on routine operating practices.

The behavior of a generator during a sudden change outside its terminals is characterized by a Thevenin equivalent with a voltage source proportional to generator rotor flux linkages and a subtransient impedance of the generator as shown in Figure 5.5, "Standard PSS®E Generator Configuration". Lenz's law states that the rotor flux linkages do not change instantaneously; therefore the Thevenin voltage retains the constant value corresponding to conditions at time, t^{-}, when the network is being solved for conditions at time, t^{+}.

Switching studies do not use a swing bus; the system's voltage level is determined by the Thevenin internal voltages of all generators, rather than by reference to terminal conditions at one.

PSS®E does not use the Thevenin equivalent directly; it uses the exactly corresponding Norton equivalent shown in Figure 5.8, "Generator-Network Coupling Models for Power Flow, Switching, and Dynamic Simulation Calculations". The Norton source current is determined from the results of a power flow (t^{-}) solution. The generator dynamic impedance may be taken to be either the generator power flow attribute, ZSORCE, or the fault analysis generator attribute, ZPOS. Normal practice is to set ZSORCE equal to subtransient impedance and ZPOS equal to either transient or subtransient impedance depending upon the requirements of fault analysis. While those switching studies taking the dynamic impedance to be subtransient reactance, Z'', give an *accurate* calculation of conditions immediately after a switching, those switching studies taking the dynamic impedance to be transient reactance, Z', give an *approximate* calculation of conditions roughly three to five cycles after a switching.

The initialization of the Norton sources and changeover of boundary conditions is illustrated in Figure 9.12, "Change of Generator Boundary Condition for Switching". This function is handled by activity CONG, which initializes all source currents to correspond to the flux linkages behind the dynamic impedance (ZSORCE or

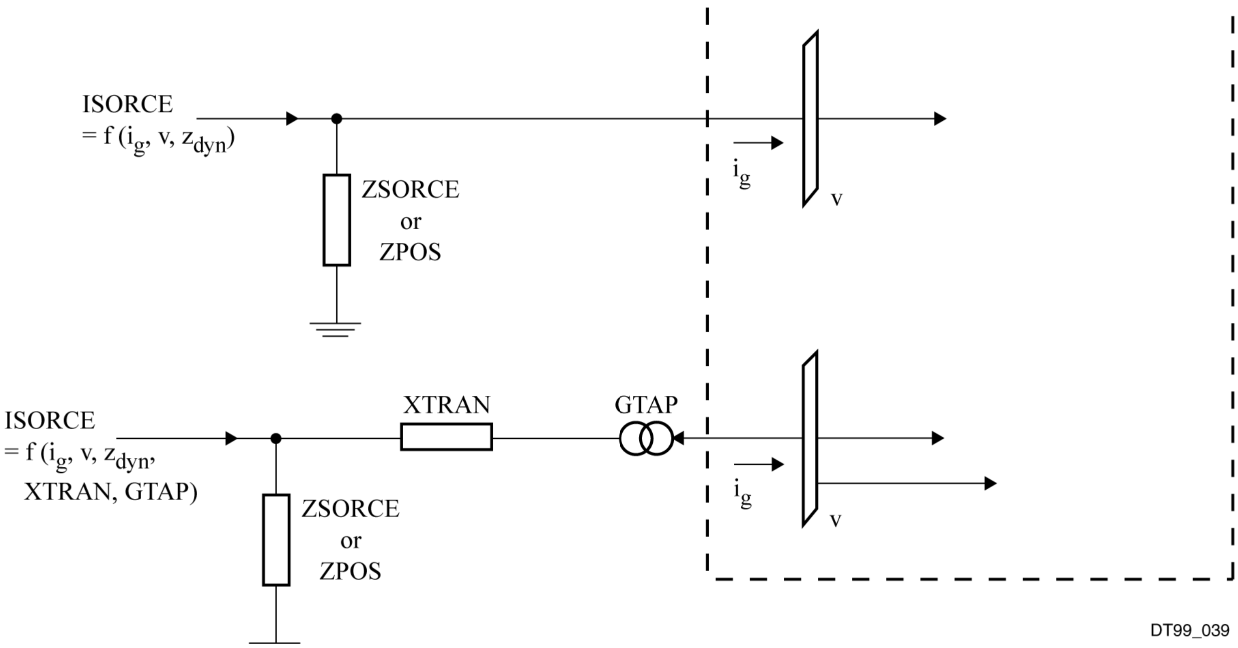
ZPOS), sets flags to cause ISORCE to be held constant in all subsequent solutions, and changes all Type 3 buses to Type 2. The choice of dynamic impedance is controlled by the suffix of the CONG command.

- CONG sets up boundary conditions on the basis of the impedance, ZSORCE.
- CONG,SQ sets up boundary conditions on the basis of the impedance, ZPOS.

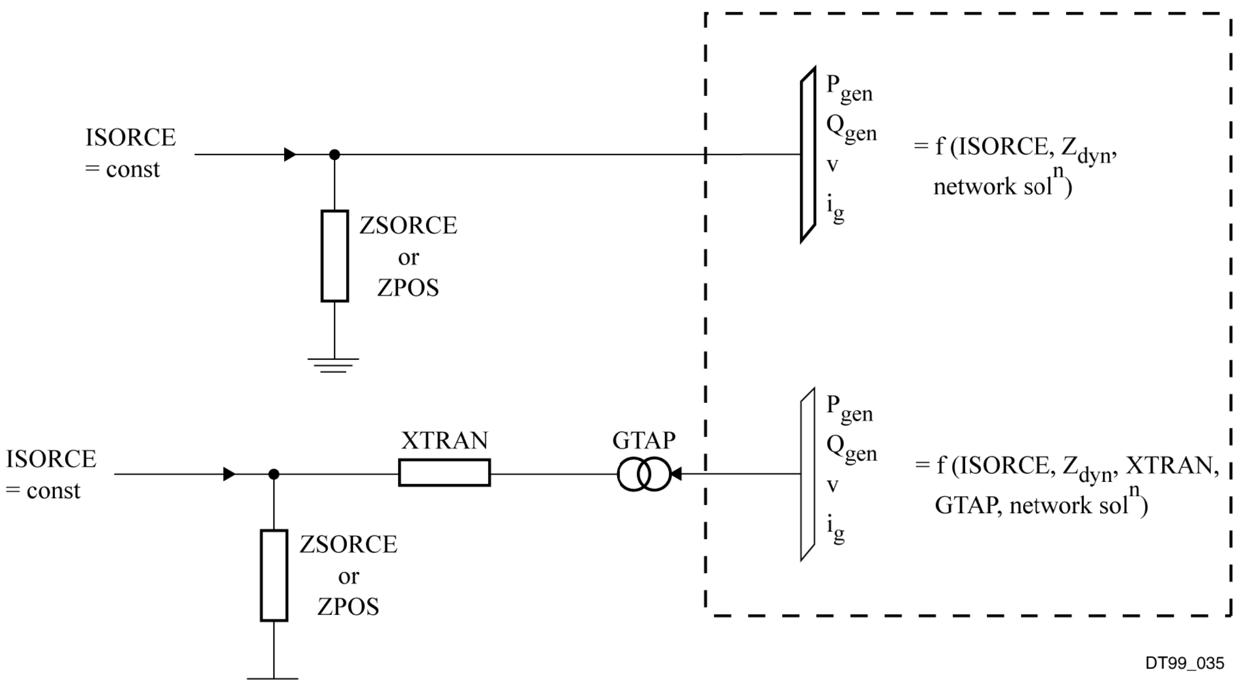
Because it changes at least one bus type code, CONG must be followed by activity ORDR.

Loads - Activity CONL

The load boundary condition for switching studies should reflect the relationship between load voltage and current during sudden changes of voltage. The constant (P,Q) characteristic used in power flow studies is generally regarded as unsuitable for switching studies. A mixture of constant current and constant impedance is usually regarded as a more accurate treatment of loads when the supply voltage is changing rapidly. Load characteristics should be adapted for switching studies by the use of activity CONL (see also Section 7.7, "Load Voltage Characteristics").



a. Power Flow - ISORCE Follows Network Solution



b. Switching - Network Solution Follows ISORCE

Figure 9.12. Change of Generator Boundary Condition for Switching

It must be recognized that all load boundary conditions established by CONL are only rough approximations to true load behavior. The approximation is usually acceptable, or the only practical possibility, for bulk transmission studies where the loads are represented at high-voltage buses and are the summation of load on many individual feeders. It should be used only with the greatest care in more specialized studies, such as industrial systems where each load may represent an individual motor.

9.6. Switching Solutions

9.6.1. Solution Procedure

Switching solutions for time, t^+, are handled by a two-step procedure:

1. Use activity FACT to construct the triangular factors of the network admittance matrix.

2. Use activity TYSL to iterate estimates of bus voltage to bring the network to balance.

This solution procedure is particularly tolerant of the wide ranges of voltages and other abnormal conditions often encountered in switching studies. It is also, incidentally, capable of reaching a bus voltage tolerance as low as 0.00001 per unit, or one-tenth of that usually regarded as normal for the Gauss-Seidel solution activity SOLV.

The sequencing of Activities for switching studies is shown in Figure 9.13, "Sequencing of Activities for Switching Studies". The preparation steps CONG, CONL, and ORDR produce a converted case representing conditions at time, t^-. It is advisable to save this converted case with activity SAVE so that it can be used as the initial condition for a sequence of switching studies. It is also advisable, and usually more important, to save the unconverted case because activity CONG is not reversible and new t^- conditions cannot be established from a case after its use. A new t^- network condition can be constructed only by applying the power flow input, manipulating Activities, and solution Activities to an unconverted case.

Switchings at time, t, may be applied with any power flow manipulating activity CHNG, DSCN, SPLT, or JOIN, for example. The switching modifies the system loading, network configuration, or both, in preparation for the t^+ solution with activities FACT and TYSL. New switchings from the original initial condition may be handled either by undoing the prior switching, applying a new one, and resolving; or by recovering the pre-switching network model as saved previously, applying the new switching, and resolving. The second course is preferable because the voltage vector of the preswitching case is usually a better initial condition estimate for the iterative solution.

Figure 9.14, "Calculation of Branch Currents Flowing into a Bus Faulted through Zero-Impedance" gives an example of the switching studies activities to obtain a pair of three-phase fault case solutions. The example follows the activity sequencing shown in Figure 9.13, "Sequencing of Activities for Switching Studies".

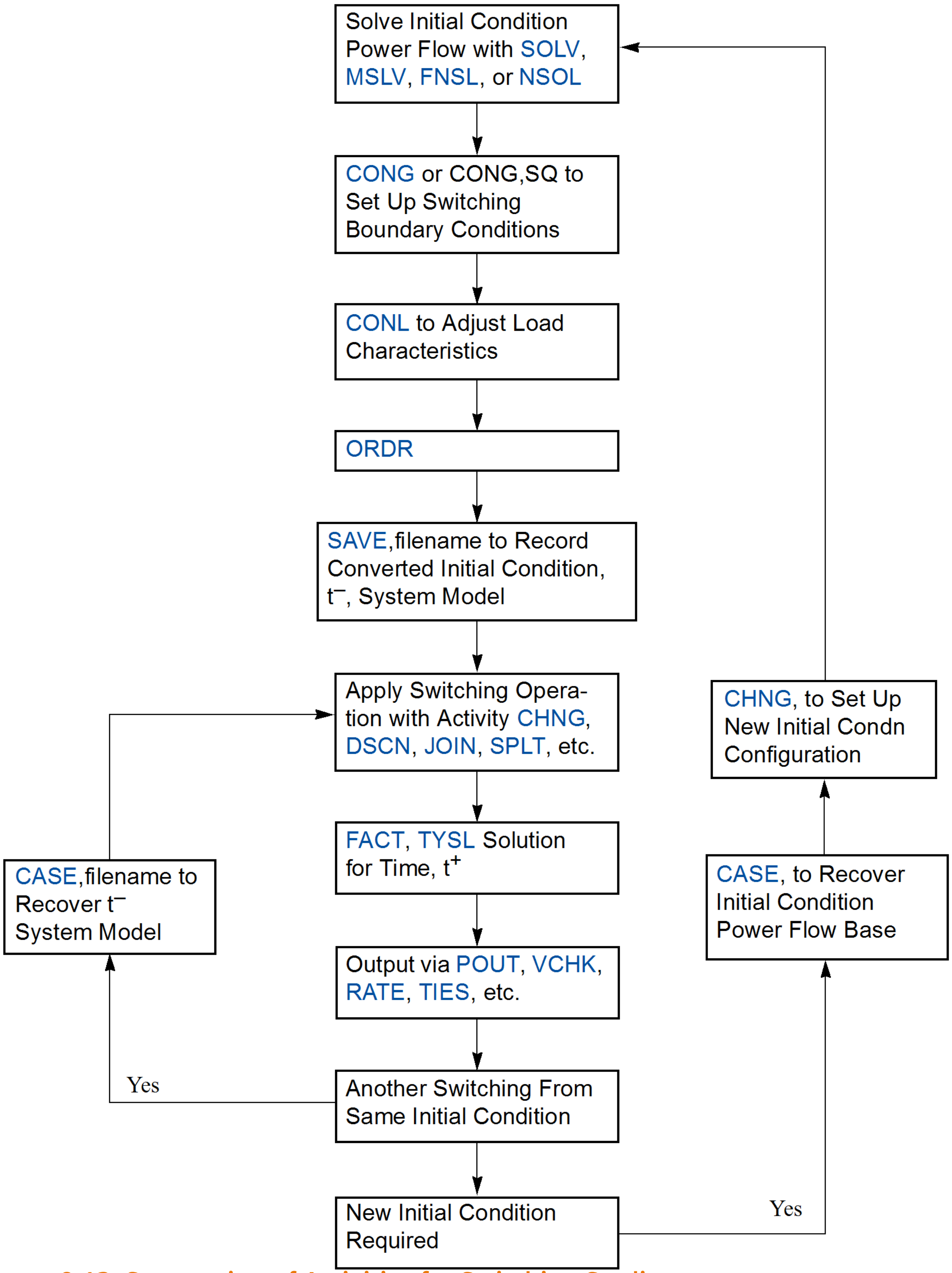


Figure 9.13. Sequencing of Activities for Switching Studies

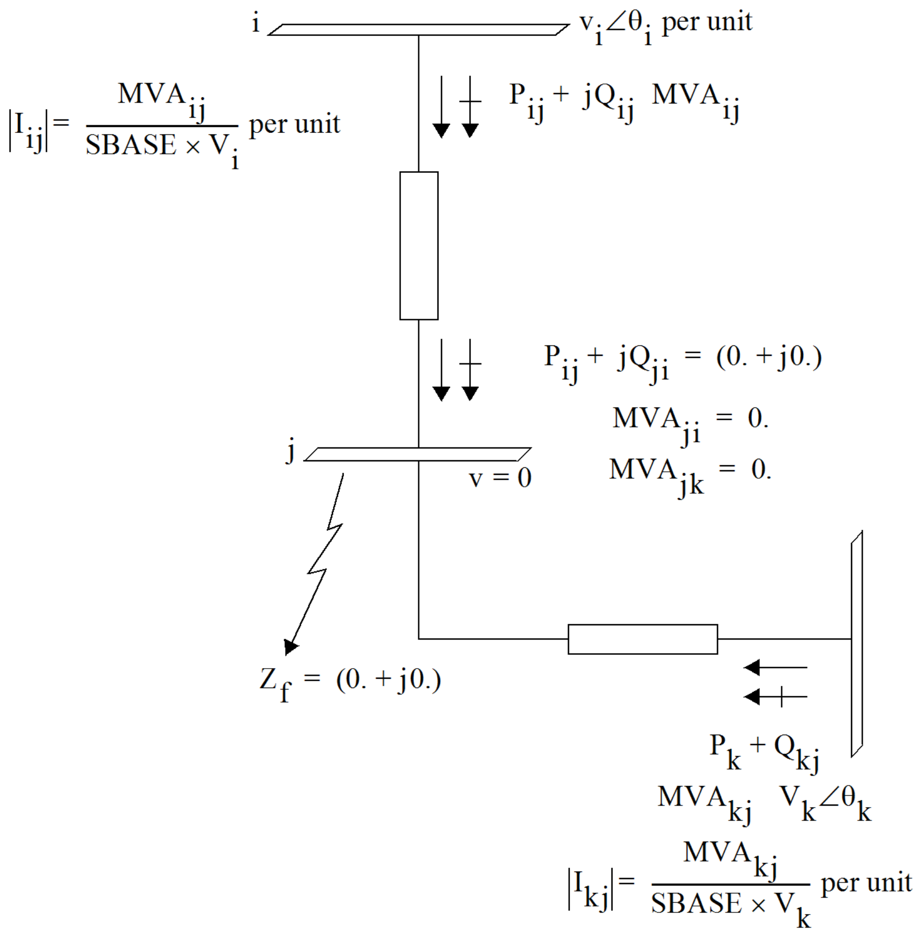


Figure 9.14. Calculation of Branch Currents Flowing into a Bus Faulted through Zero-Impedance

9.6.2. Results

After a solution has been obtained for the instant, t^+, with activities FACT and TYSL, output of results is handled by the standard power flow output Activities such as POUT, VCHK, RATE, and GEOL. The formats and significance of these activities are unchanged except that POUT displays the net current flowing to ground at any bus where voltage is below 0.1 per unit. This current value is expressed in terms of fault MVA where

FAULT MVA = $\sqrt{3}$ × (Base Voltage, kV) × (Current, A) × 10^{-3}

Because the output reports, particularly those of POUT, display power flow results, the current flowing in faults and branches must be calculated from the displays of voltage and complex power or MVA flow. Current in amperes is obtained from

$$\left|\text{Current}\right| = \frac{\text{MVA Flow}}{\sqrt{3} \times (\text{Voltage, kV}) \times (1 \times 10^3)}\ \text{A}$$

Per-unit current is obtained from

$$\left|\text{Current}\right| = \frac{\text{MVA Flow}}{(\text{System Base MVA}) \times (\text{Voltage, per unit})}\ \text{per unit}$$

The calculation of currents flowing into a bus faulted through a zero impedance is illustrated by Figure 9.14, "Calculation of Branch Currents Flowing into a Bus Faulted through Zero-Impedance". Because the voltage at the faulted bus is zero, the MVA flows into it are zero even though the currents are nonzero. The currents in the branches feeding the fault must be determined from the MVA flows and voltages at the ends that are away from the fault.

9.7. Transformer Nameplate Winding MVA Data

Each data record has the following format:

```
I, J, K, Ckt, Sbase 1-2, Sbase 2-3, Sbase 3-1
```

where:

I Winding 1 bus number

J Winding 2 bus number

K Winding 3 bus number (=0 for two-winding transformer)

Ckt Transformer circuit identifier

Sbase 1-2 Winding 1 to winding 2 Nameplate MVA

Sbase 2-3 Winding 2 to winding 3 Nameplate MVA (not required for two-winding transformer)

Sbase 3-1 Winding 3 to winding 1 Nameplate MVA (not required for two-winding transformer)

Chapter 10
Contingency Analysis

PSS®E provides comprehensive tools to perform deterministic and probabilistic reliability assessment. Activities that evaluate reliability in a deterministic manner include ac contingency analysis, multiple-level ac contingency analysis, as well as PV/QV analysis, and so on, which use power flow solutions as basic computation engines. On the other hand, Reliability Assessment and Substation Reliability Assessment (SRA) evaluate reliability of a transmission and distribution network, and a substation configuration in terms of probabilistic indices respectively. The indices are a combination of probability and consequence. In other words, reliability assessment functions must recognize the possibility of failures and severity and degree of their consequence. Both of these two functions adopt contingency enumeration methodology. The basic idea of the enumeration method is to perform reliability assessment using an iterative process including the following steps:

1. Select a system state: a single element or common mode outage.
2. Evaluate the system state to judge if it is a failure state which causes system operation limit violations.
3. Calculate probabilistic indices for the failure state.
4. Calculate cumulative probabilistic indices.

The approaches to system state selection, state evaluation, and calculations of indices are different for Reliability Assessment and Substation Reliability Assessment. These methods are discussed in the section.

From an electricity customer's point of view, how often and for how long load is interrupted due to failure events is of interest. Load curtailments occur not only because of isolated buses created by a contingency, but also because of the fact that a contingency may cause system operation limit violations, such as flow overloading and bus voltage violations, and force load curtailments. In Reliability Assessment analysis, evaluation of a system state must include power flow and corrective actions, such as generation re-dispatch, load shedding. Corrective action analysis applies an optimal power flow (OPF) technique based on Linear Programming (LP) to eliminate violations, with the objective function of minimum load curtailments. Applications of corrective action can be found in Contingency Analysis and dc and ac corrective action analysis. Corrective action analysis differs from PSS®E OPF in that it gets data from the Subsystem Description Data File and Monitored Element Data File and uses a solved power flow solution as the starting point of optimal search.

10.1. Probabilistic Reliability Assessment

The behavior of power systems is probabilistic. Loads are always uncertain. The events that cause the outages my vary, but are always in the form of unplanned events such as lightning strikes, falling tree limbs, human errors, and so on; these events are thus of a random nature. The weakness of deterministic reliability analysis is that it does not reflect the probabilistic nature of power system behavior, but treats every contingency tested equally significant. Probabilistic reliability assessment is provided to calculate probabilistic indices of system problems and load curtailments as follows:

1. Probabilistic indices of flow overloads
2. Probabilistic indices of voltage violations
3. Expected unserved energy
4. Interrupted power

The procedure of probabilistic reliability assessment analysis is shown in Figure 10.1, "Procedure of Probabilistic Reliability Assessment". To run probabilistic reliability assessment analysis, contingency analysis output files (*.acc) must be created with Multiple-level Contingency Analysis function in that the function builds element and event tables during contingency analysis by which the outage statistics are matched with contingencies.

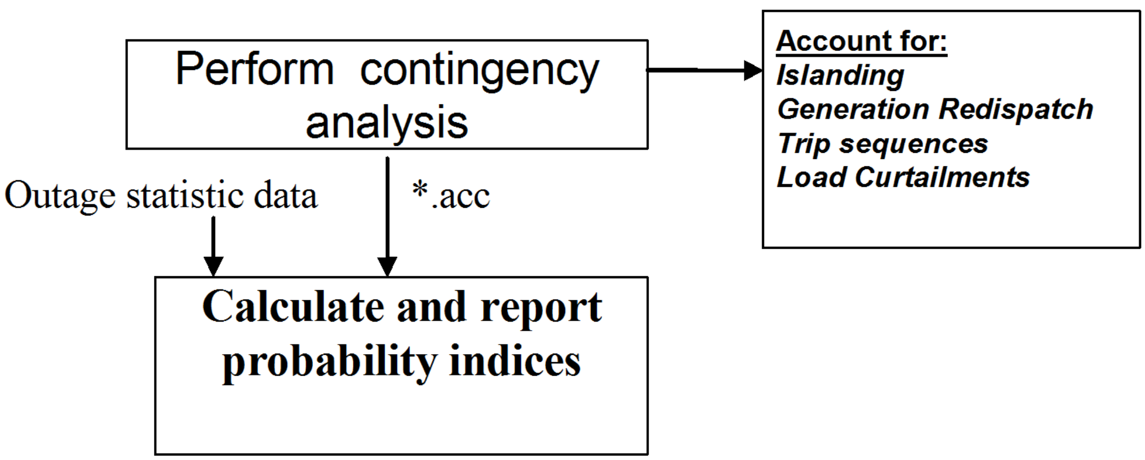


Figure 10.1. Procedure of Probabilistic Reliability Assessment

10.1.1. Introduction of Probabilistic Calculation

Power systems are continuously operating systems. Maintenance is performed to keep components in good condition and repairs are performed promptly in order to restore service. Therefore, each component can be modeled with a two-state model, as illustrated in Figure 10.2, "Two-State Model". At any time, a component can be in one of two states: in-service (available) and out-of-service (unavailable).

Figure 10.2. Two-State Model

The transition from the in-service state to the outage state is called a failure event, and is assumed to occur at a constant rate λ , in failures per year; the transition from the out-of-service state to the in-service state is called a restoration event, and is also assumed to occur at a constant rate μ , in restorations per year. The mean duration that the equipment is in service is m years, while the mean duration that it is out of service is r years.

The probability that the equipment is in-service is:

$$P_{IN} = \frac{m}{m + r}$$

The probability that it is out-of-service is:

$$P_{OUT} = \frac{r}{m + r}$$

Thus, POUT+PIN=1. The unavailability POUT is the index used to assess reliability of the system; typically, its units are hours/year or minutes/year.

The frequency (in occurrences/year) to transition from the in-service to the outage state is equal to the frequency to transition from the outage state to the in-service state, and is given by:

$$F = P_{IN} * \lambda = P_{OUT} * \mu$$

The average duration (in hours or years) that the equipment is in the outage state is:

$$D = \frac{P_{OUT}}{F}$$

Hence, to represent the probability of an outage for this equipment, only two parameters are required: F and D. Other characteristics can be derived from these two parameters:

$$\mu = \frac{1}{D}$$

$$\lambda = \frac{F}{1 - F * D}$$

$$m = \frac{1 - F * D}{F}$$

10.1.2. Outage Model

There are several different methods to classify transmission outages; for example they can be classified in two categories: forced outages and scheduled outages; or they can be classified into: independent and dependent outages. A sample system as shown in Figure 10.3, "Illustration of a Multiple Element Outage" is used to illustrate each type of outage model discussed below. The example is a portion of savnw test system.

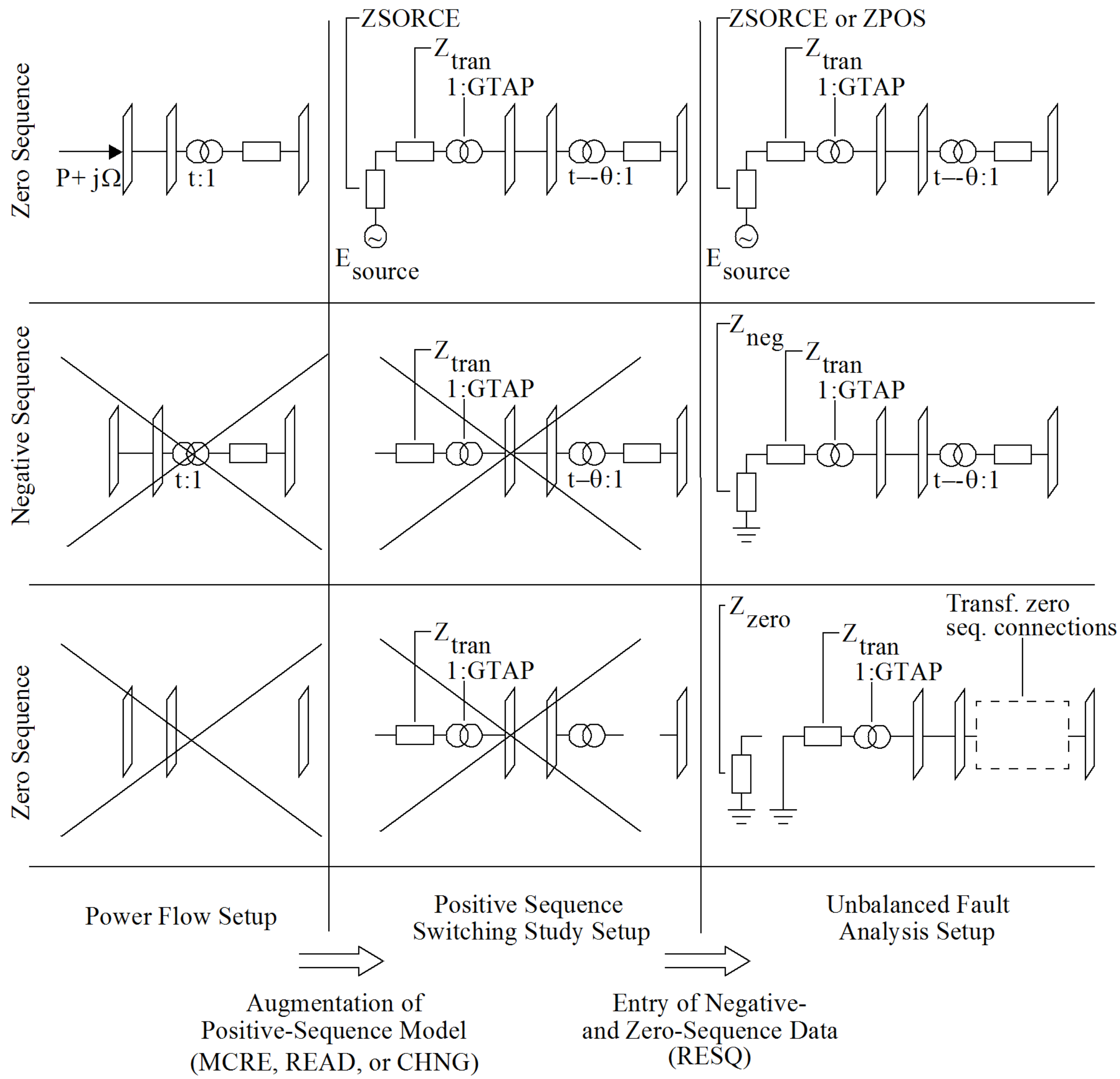


Figure 10.3. Illustration of a Multiple Element Outage

Independent Single Element Outage Model: An independent single outage is the failure of one unique component, and is not related in terms of its cause to any other failures that may occur at the same time. For each component, frequency and duration of the independent outage must be specified. e.g., outage of branch A is an independent single element outage.

Multiple Independent Outage: Each outage is due to an independent cause but occurs with overlapping durations. e.g., in the outage of branches A and B being out-of-service, this may come about from separate lightning strikes on the segments of the branches A and B that are not on a common tower. The lightning strikes do not have to occur simultaneously, but the outage of the second circuit occurs while the first circuit is still out-of-service. Such failure bunching is likely to occur during lightning storms. The model can be expanded to include multiple independent event outage. Each event may consists of more than one outage elements, and is due to an independent cause. e.g, within multiple-level contingency analysis, N-2 and N-3 contingencies are considered as independent multiple element outages. For a N-2 contingency analysis, all outages that are a combination of outage events from the primary event list and a secondary event list are treated as independent multiple element outages of two events.

Common Mode Outage: The outage is due to a single cause resulting in a common mode outage of several elements. In the outage of branches A and B being out-of-service, this may take the form of a lightning strike on the section of the line that has two circuits on the same tower line. Another form of common mode outage occurs when a circuit is tapped with no breaker, forming a three-terminal line. Any faults on such a line result in the simultaneous outage of all three sections.

Substation-related Outage or Dependent Multiple Outage: In this type of outage, there is an initial or primary event due to an independent cause. This is followed by additional or secondary outages due to events that are dependent on the primary event. Frequently, the dependent event occurs from the operations at substations or line terminations, such as: stuck breaker, breaker fault, bus section fault and protection failure. In the outage of branches A and B being out-of-service, consider a lightning strike on branch A. The fault is detected by protection at the substation that it shares with branch B. The protection initiates the opening of a number of circuit breakers, however, a breaker failure such as a stuck breaker occurs. This then requires additional breakers to open on backup. Branch B is thus opened due to the backup operation. Clearly, the configuration of the substations and the design of protection have an impact on the probability of the secondary outages.

Probability of Multiple Independent Outage

The probabilities and frequencies of independent multiple element outages can be computed directly from the frequencies and durations of the individual independent events. For example, the probability of multiple independent outage of branches A and B being out is given by:

$$P_{AB}^{mult,ind} = P_A * P_B = \frac{(F_A * D_A)(F_B * D_B)}{8760}$$

Where PA and PB are the probabilities of individual outage for branches A and B, FA and FB are the frequencies, and DA and DB are the corresponding average durations in hours.

Computation of the frequency of the multiple independent outage is given as follows:

$$F_{AB}^{mult,ind} = F_A P_B + F_B P_A$$

Average duration is then given by:

$$D_{AB}^{mult,ind} = \frac{P_{AB}^{mult,ind}}{F_{AB}^{mult,ind}}$$

The probabilities and frequencies of common mode and substation-related outages cannot be derived directly from the single element outage statistics. These outage events must therefore be explicitly specified with their corresponding frequency of occurrence and outage duration in the multiple element outage data file.

The outage combination of elements A and B may thus cover several outage event types. The total probability for the contingency P_{AB}^{TOTAL} is obtained by adding the probability of the multiple, independent event, the probability of the common mode and station-related events, $P_{AB}^{common+dep}$:

$$P_{AB}^{TOTAL} = P_{AB}^{common+dep} + P_{AB}^{mult,ind}$$

10.1.3. Probabilistic Indices

This section discusses the methodology used within PSS ®E to calculate probabilistic indices. The base case and mutually exclusive contingency cases form a state space of an electricity system as shown in Figure 10.4, "System State Space Diagram". Each node represents an operation state: base case or a contingency case. The sum of probabilities of all states is equal to1. Probabilistic indices of system problems are computed by identifying the set of states that satisfy failure criteria and the transition rates from any state inside the set to a state outside of the set. In Figure 10.4, "System State Space Diagram", a yellow node represents a state that has violations; all yellow nodes form the set of states that satisfy failure criteria, which is referred to as S. Failure criteria include branch overloads, bus voltages outside high or low limits, bus change exceeding deviation criteria and loss of load.

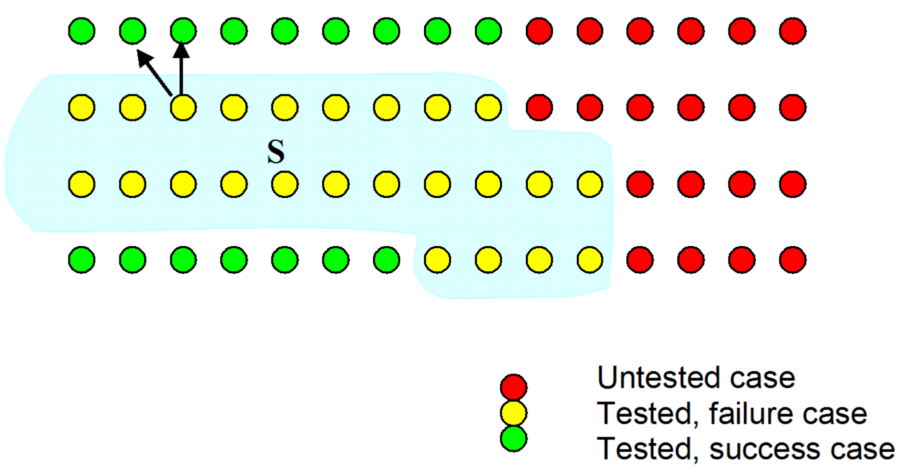


Figure 10.4. System State Space Diagram

The probability of system problems is defined as:

$$P_{FAILURE} = \sum_{i \in S} P_i$$

Where Pi is the probability of state i that satisfies failure criteria.

The frequency of system problem is defined as:

$$F_{FAILURE} = \sum_{i \in S} \sum_{j \notin S} F_{ij}$$

Where Fij is the frequency to transition from state i inside the set to state j outside the set.

The duration D is defined as:

$D = P_{FAILURE} / F_{FAILURE}$

Probability of System Problems

The probabilities of problems of the system or its components are the sum of probabilities of the states that cause these failures, and are given by

$$P_{FAILURE} = \sum_{i \in S} P_i = \sum_{i \in S} \left(\prod_{j=1}^{N} p_j \prod_{k=1}^{M} (1 - p_k) \right)$$

Where Pi is the probability of state i, pj is the probability of element j being out-of-service, N and M are numbers of elements being out-of-service and in-service respectively.

The above methodology is fairly simple when it is run on a two-element system; where there are four states that contribute to the probability of problems. For a three element system, there are eight states, and a n-3 contingency analysis. For the system with 20 elements, we have over a million states, and as deep as a n-20 contingency analysis. Therefore, it is not practical to test all these states to form a completed state space.

Assumption I: All untested contingency cases have no contributions to unreliability of the system. The set S consists of only all tested states with problems.

Secondly, it is difficult to calculate the probability of each operation state of an electric power system. For example, for a system with 20 elements, the probability of any state is the product of 20 element probabilities. Practical power systems involve many more than 20 elements. It becomes computationally burdensome to calculate probabilities of all states. Furthermore, statistics of components outside the study system may not be known.

Assumption II: The loss of elements in addition to those considered in the contingency will not result in a less severe situation. In other words, if a contingency event results in system problems, all multiple-event contingencies that consist of this contingency event will result in the same system problems or more. The contribution to unreliability of a state is equal to the sum of probabilities of all states that consists of elements that are out-of-service in the state. Therefore, an approximation of the probability of problems is:

$$P_{FAILURE} = \sum_{i \in S} P_i \approx \sum_{i \in S} \left(\prod_{j=1}^{N} p_j \right)$$

This procedure may result in a high estimate of frequency of problems for the contingencies tested, because a failure state represents a subset of states that consists of the elements being out-of-service in this failure state and some failure contingencies may be counted several times. The problem is referred to as 'double counting' problem. It is illustrated with the example of a system with two elements A and B. Considering single element events and independent multiple element events only, there are four possible states for the two-element system. Assume that the probability of an element being out-of-service is 0.1 (and the probability of an element being in-service is 0.9). As shown in Table 10.1, “Probability States of a Two-Element System”, the four possible states are mutually exclusive and exhaustive and the probabilities add up to 1.00. Assuming that events 2, 3 and 4 all result in system failure, the probability of failure is 0.09 + 0.09 + 0.01 = 0.19 with exact model.

Table 1: Probability States of a Two-Element System

State Number	Element Status		State Probability	System Problem
	A	B		
1	IN	IN	0.9 x 0.9 = 0.81	no
2	OUT	IN	0.1 x 0.9 = 0.09	yes
3	IN	OUT	0.9 x 0.1 = 0.09	yes
4	OUT	OUT	0.1 x 0.1 = 0.01	yes
	TOTAL		1.00	

Table 10.1. Probability States of a Two-Element System

Note that in the nomenclature used here, state 1 is the base case state, events 2 and 3 are N-1 contingency states, and event 4 is a N-2 contingency state. On the above two assumptions, the probability of system problem is computed as 0.1 + 0.1 + 0.01 = 0.21. This calculation is based only on probabilities of elements being out-of-service, and ignores probabilities of elements being in-service at the time.

As a result, the probabilities corresponding to event 4 have been counted three times. The approximation thus is subject to the phenomenon known as *double-counting*. On the other hand, it does provide one important feature: the calculation requirement is much simpler than the precise formula.

The errors grow smaller as the probabilities of outages are reduced to values that are more representative of transmission element outages. The error between the precise and the approximate formulas become appreciable at outage probabilities of 0.01 or higher.

When a partial state space is considered (that is, only some states are evaluated in contingency analysis), under-estimation is found in the results. e.g., when only N-1 contingency analysis is applied for the above two-element system, the probability of system problems is 0.18 from exact model and 0.2 from approximate model. This under-estimation will worsen with increasing number of elements in the system and increasing component outage frequency.

Frequency of System Problems

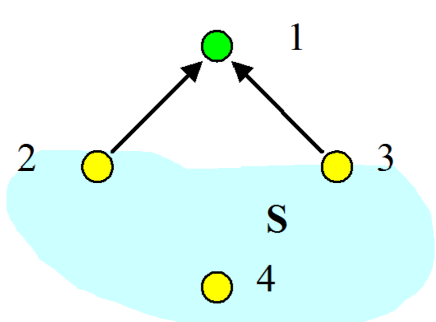


Figure 10.5. State Space Diagram of Two-Element System

The frequency is the sum of frequencies of transition from a state inside the set to a state outside the set. It is given by:

$$F_{FAILURE} = \sum_{i \in S} \sum_{j \notin S} F_{ij}$$

Assume in the above two-element system, the frequencies of A and B out-of-service are 0.1. Therefore, the frequency of system problem is the sum of frequencies to transitions from states 2 and 3 to state 1 respectively as shown in Figure 10.5, "State Space Diagram of Two-Element System":

$F_{FAILURE} = F21 + F31 = 0.18$

The 'dimension disaster' also exists in calculations of frequency of system problems. For 20 elements, we have over a million states, and as deep as a N-20 contingency, it is not possible to figure out all transitions from a state inside the set to a state outside the set.

Similarly the frequency of a system problem is computed by a simple summation of the frequency of each contingency that causes failure. The approximate frequency of the problem, based on the approximate probability of failure is defined as follows:

$$F_{FAILURE} \approx \sum_{i} F_i$$

Where Fi is the frequency of state i.

This procedure may result in a high estimate of frequency of failure for the contingencies tested, due to the reasons discussed above. The frequency of both elements out-of-service is 0.02, by using equations of independent multiple element outage frequency.

$$F_{FAILURE} \approx \sum_{i} F_i = F_2 + F_3 + F_4 = 0.1 + 0.1 + 0.02 = 0.22$$

The frequencies to transition from state 4 to state 2 and from state 4 to state 3 should not be counted because states 2, 3 and 4 all belong the set, while they are double counted in the approximate algorithm.

By the use of exact algorithms, it is possible to compute frequency without double-counting. These algorithms are, however, very time consuming. Experience has indicated that the double-counting effect is normally not severe, as long as the size of the system for which indices are computed is reasonably small. The effect of double-counting may become significant as generator outages with much larger outage frequencies are added to the reliability study.

Similar if not all states are evaluated in contingency analysis, the results are under-estimated. This under-estimation will worsen with an increasing number of elements in the system and an increasing component outage frequency.

Approximate frequency will be a meaningful and consistent measure of reliability for the purpose of comparing system alternatives and for the purpose of establishing the relative reliability of different portions of the system. This measure should also realistically approximate the number of occurrences of specific system problems that can be expected due to the class of contingencies investigated in the contingency analysis. Statistically significant differences between computed and actual (observed) reliability are more likely to be due to limitations in outage models and outage data than to the double-counting problem.

Duration of System Problems

The duration measure in Hours is the average duration of the outage events causing the system problems. It is defined as follows:

DFAILURE= PFAILURE/FFAILURE

The average duration of the system problems themselves is also a function of the corrective actions that can be taken and the duration of the particular system condition in the base case. Therefore, the average duration of a system problem will generally be shorter than the value given in the probabilistic reliability assessment output.

Impact of Problems

The impacts of problems are combinations of probability and violations. The general form of probabilistic impact indices is defined as:

Ip = Pi * Vi

For a monitored branch flow overload, it is in percent loading on a given rating set in the form of:

$I_p = P_i * (L_{ik} / R_k - 1)$

Where Lik and Rk are the loading subject to contingency i and rating on branch k respectively.

For a monitored bus voltage violation, it is in per unit in the form of:

$I_p = P_i * (V_{ik} - V_{limit})$

Where V_{ik} and V_{limit} are the voltage at bus k subject to contingency i and the bus voltage limit respectively.

For a load curtailment, the violation is taken as the loss of load in MW. Normally, the impact of load curtailments is referred to expected unserved energy in MW.hour/year.

Normalized Probability

The probability of a contingency is the product of in-service probabilities of elements being in-service and out-of-service probabilities of elements being out-of-service, and is defined as:

$$P_i = \prod_j^N p_j \prod_k^M (1 - p_k)$$

The common factor is defined as the product of in-service probabilities of all elements:

$$C = \prod_k^{N+M} (1 - p_k)$$

The normalized probability is defined as:

$P_i^* = P_i / C$

The advantage of the use of normalized probability is that probability calculation is not subject to the double counting problem.

10.1.4. Probabilistic Load Curtailment Assessment

Another form of reliability assessment run by PSS®E is based on load curtailments due to stochastic events. This type of assessment focuses on the impact of unreliability on the customers. The basic premise in probabilistic load curtailment assessment is the following: a contingency of a certain probability that causes an overload on a transmission element is not, of itself, of interest to the consumers of electrical power. However, the consumer would be interested in knowing that the same contingency if allowed to proceed unmitigated could result in curtailment of some or all of their electrical demand.

Hence, the objective of probabilistic load curtailment assessment is not one of finding out the number and severity of system problems, but rather, of determining how customers can be affected by the problems. This requires that the assessment proceeds beyond identifying problems by recognizing the actions that might take place to mitigate the problems. PSS®E approaches this as an optimal power flow application (i.e., corrective actions).

Basis for Load Curtailments

Load curtailments can occur in three different ways in contingency analysis:

- A contingency that causes separation (or islanding) of a portion of the network in which the island has insufficient generation to meet the load.
- A contingency that initiates a trip event in which the trip sequence causes load to be shed.
- A contingency that has an overload or voltage violation after redispatch and tripping and for which corrective actions involving load curtailment have been specified.

Each of these three ways represents a stage in the evaluation of a contingency. In the sequence given above, these stages are known as: post contingency, post tripping, and post corrective actions. Post-tripping and post corrective action stages may be skipped by disabling these options prior to multiple level contingency analysis. The solutions at specified stages are saved in the contingency analysis output files. Within probabilistic assessment, you can select the stage at which load curtailments are to be reported via the output option mode. Therefore, flexibility is given to calculate and report reliability indices for different categories of loss of load. Table 10.2, "Load Curtailments at each Stage" lists the load curtailments from each stage. To reflect completed load curtailments within contingency analysis, all options that may result in loss of loads need to be included

Table 10.2. Load Curtailments at each Stage

Mode	Failure Criteria Check Stage	Detailed Load Loss Report		
		From Islanding	From Tripping	From Corrective Action
1	At post contingency stage	YES	N/A	N/A
2	At post-tripping stage	YES	NO	N/A

Mode	Failure Criteria Check Stage	Detailed Load Loss Report		
		From Islanding	From Tripping	From Corrective Action
		NO	YES	N/A
		YES	YES	N/A
3	At post-corrective action stage	YES	NO	NO
		NO	YES	NO
		NO	NO	YES
		YES	YES	NO
		YES	NO	YES
		NO	YES	YES
		YES	YES	YES

Probabilistic Load Curtailment Indices

Note that a number of the indices are 'Energy' indices, in that they depend on an assumed duration to which the base case applies. This duration is 8,760 hours (one year).

The following probabilistic indices are calculated for the system and individual buses. Interrupted power in MW/year is defined as:

$$I.P. = \sum_{i \in S} Plold_i * F_i$$

Where, for system indices, Ploldi is total MW load lost in state i and for an individual bus, it is total MW load lost at the bus, and Fi is frequency of state i.

Average interrupted power in MW/occurrence is defined as:

$$A.I.P. = \frac{\sum_{i \in S} Plold_i * F_i}{\sum_{i \in S} F_i}$$

Expected unserved energy in MW.h/year is defined as:

$$E.U.E. = \sum_{i \in S} Plold_i * Fi * D_i$$

Two other indices may be of interest: the bulk power interruption index and the bulk energy curtailment index. The bulk power interruption index is defined as:

$$B.I.P. = \frac{\sum Plold_i * F_i}{Pload}$$

Where Pload is the sum of load in the study area. Similarly bulk energy not supplied is defined as:

$$\text{B.E.U.E.} = \frac{\sum \text{Plold}_i * F_i * D_i}{\text{Pload}}$$

All indices are based on an assumption of one full year (8760 hours) of operation using the present base case.

10.1.5. Examples

The savnw system is used in probabilistic reliability assessment examples. The outage statistic data is summarized in Figure 10.6, "Outage Statistic Data". The frequencies and durations are 0.01 (Occurrences) and 10 (Hours) for non-transformer branches, and 0.01 (Occurrences) and 100 (Hours) for transformers. A N-1 contingency analysis is run with single branch outages only.

```
LINE FROM BUS      151 TO BUS      201 CKT 1  0.01000  10.000
LINE FROM BUS      152 TO BUS      202 CKT 1  0.01000  10.000
LINE FROM BUS      152 TO BUS     3004 CKT 1  0.01000  10.000
LINE FROM BUS      153 TO BUS      154 CKT 1  0.01000  10.000
LINE FROM BUS      153 TO BUS      154 CKT 2  0.01000  10.000
LINE FROM BUS      153 TO BUS     3006 CKT 1  0.01000  10.000
LINE FROM BUS      154 TO BUS      203 CKT 1  0.01000  10.000
LINE FROM BUS      154 TO BUS      205 CKT 1  0.01000  10.000
LINE FROM BUS      154 TO BUS     3008 CKT 1  0.01000  10.000
LINE FROM BUS      201 TO BUS      202 CKT 1  0.01000  10.000
LINE FROM BUS      201 TO BUS      204 CKT 1  0.01000  10.000
LINE FROM BUS      203 TO BUS      205 CKT 1  0.01000  10.000
LINE FROM BUS      203 TO BUS      205 CKT 2  0.01000  10.000
LINE FROM BUS     3001 TO BUS     3003 CKT 1  0.01000  10.000
LINE FROM BUS     3002 TO BUS     3004 CKT 1  0.01000  10.000
LINE FROM BUS     3003 TO BUS     3005 CKT 1  0.01000  10.000
LINE FROM BUS     3003 TO BUS     3005 CKT 2  0.01000  10.000
LINE FROM BUS     3005 TO BUS     3006 CKT 1  0.01000  10.000
LINE FROM BUS     3005 TO BUS     3007 CKT 1  0.01000  10.000
LINE FROM BUS     3005 TO BUS     3008 CKT 1  0.01000  10.000
/END OF NON-TRANSFORMER BRANCH STATISTIC DATA
LINE FROM BUS      101 TO BUS      151 CKT 1   0.01000   100.00
LINE FROM BUS      102 TO BUS      151 CKT 1   0.01000   100.00
LINE FROM BUS      152 TO BUS      153 CKT 1   0.01000   100.00
LINE FROM BUS      201 TO BUS      211 CKT 1   0.01000   100.00
LINE FROM BUS      202 TO BUS      203 CKT 1   0.01000   100.00
LINE FROM BUS      205 TO BUS      206 CKT 1   0.01000   100.00
LINE FROM BUS     3001 TO BUS     3002 CKT 1   0.01000   100.00
LINE FROM BUS     3001 TO BUS     3011 CKT 1   0.01000   100.00
LINE FROM BUS     3004 TO BUS     3005 CKT 1   0.01000   100.00
LINE FROM BUS     3008 TO BUS     3018 CKT 1   0.01000   100.00
/END OF TRANSFORMER STATISTIC DATA
/END OF THREE WINDING TRANSFORMER STATISTIC DATA
/END OF UNIT STATISTIC DATA
END
```

Figure 10.6. Outage Statistic Data

Figure 10.7, "System Problem Probabilistic Indices" shows probabilistic indices for system problems. The frequency and probability of overload problem are 0.04 and 3.1 respectively. Four contingency cases cause flow overloads, the maximum loading is 261 percent of the given rating set based on contingency ISLAND 3. The details on overload violations are presented in overload violation report as shown in Figure 10.8, "Overload Violation Report" created by Single Run Report Function. Because the frequency of each single element contingency is 0.01, the sum of frequencies of these contingency cases is then 0.04. Three of them are single transformer outages (ISLAND 1, ISLAND 2 AND ISLAND 3) with probability of 1.0, and one non-transformer branch outage (OVRLOD 8) with probability of 0.1, therefore, the probability of overload violation is 3.1.

Frequency, duration, probability and impact are presented for each voltage monitor record. e.g., the frequency and probability of voltage violation problem for the voltage monitor recorder 'AREA 2 BUSES WITH VOLTAGE LESS THAN 0.940 (pu)' are 0.1 and 1.9; there are ten contingency cases in which voltages break the limit. The details on voltage violations are presented in voltage violation report created by Single Run Report Function as shown in Figure 10.9, "Voltage Violation Report", one of them is transformer outage (ISLAND 6) with the probability of 1, others are non-transformer branch outages with the probabilities of 0.1, therefore, the probability of the voltage violation is 1.9.

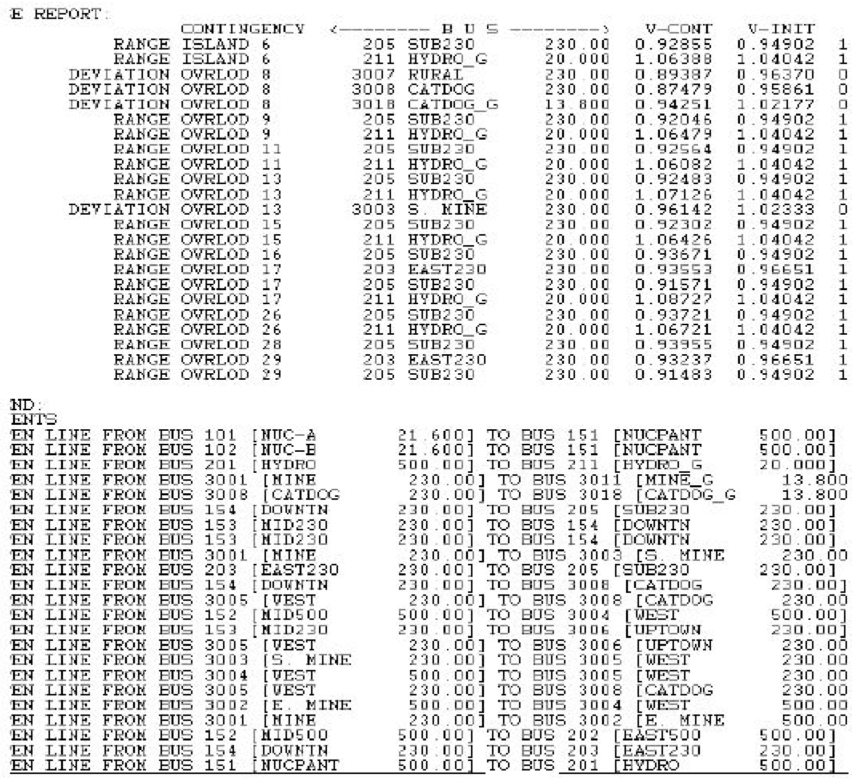
```
                                                           FREQ. DURATION   PROB.   IMPACT NO. OF   WORST. WORST CONT.
<--           F A I L U R E   C R I T E R I A         --> (OC/Y)  (HOURS)   (H/Y)          CONT.   VIOL.
AREA 2 BUSES WITH VOLTAGE LESS THAN 0.940 (PU)            0.1000     19.0     1.9     0.02     10    0.915 OVRLOD 29
ZONE 5 BUSES WITH VOLTAGE DROP BEYOND 0.060 (PU)          0.0200     10.0     0.2     0.01      2    0.084 OVRLOD 8
AREA 2 BUSES WITH VOLTAGE GREATER THAN 1.060 (PU)         0.0700     22.9     1.6     0.01      7    1.087 OVRLOD 17
OVERLOAD (%)                                              0.0400     77.5     3.1     5.87      4  261.250 ISLAND 3
LOSS OF LOAD (MW)                                         0.0200     55.0     1.1  3220.00      2 3200.000 ISLAND 5
NOT CONVERGE                                              0.0600     55.0     3.3               6
SUBSYSTEM 'ALL' TOTAL                                     0.2200     42.7     9.4              22
```

Figure 10-7. System Problem Probabilistic Indices

Figure 10.7. System Problem Probabilistic Indices

```
<---------------- MULTI-SECTION LINE ----------------> <----------------- MONITORED BRANCH -----------------> CONTINGENCY   RATING    FLOW      %
                                                         INTERFACE WEST                                      ISLAND 1      200.0    518.6   259.3
                                                         INTERFACE WEST                                      ISLAND 2      200.0    518.6   259.3
                                                         INTERFACE WEST                                      ISLAND 3      200.0    405.3   202.6
                                                         INTERFACE EAST                                      ISLAND 3      350.0   -914.4   261.2
                                                     203*EAST230      230.00    154 DOWNTN        230.00 1   OVRLOD 8      200.0    278.8   148.2

MONITORED VOLTAGE REPORT:
SYSTEM                           CONTINGENCY  <-------- B U S -------->  V-CONT   V-INIT   V-MAX    V-MIN      Four contingency cases
                                                                                                              result in overload violations
CONTINGENCY LEGEND:
LABEL          EVENTS
ISLAND 1     : OPEN LINE FROM BUS 101 [NUC-A       21.600] TO BUS 151 [NUCPANT      500.00] CKT 1
ISLAND 2     : OPEN LINE FROM BUS 102 [NUC-B       21.600] TO BUS 151 [NUCPANT      500.00] CKT 1
ISLAND 3     : OPEN LINE FROM BUS 201 [HYDRO       500.00] TO BUS 211 [HYDRO_G      20.000] CKT 1
OVRLOD 8     : OPEN LINE FROM BUS 154 [DOWNTN      230.00] TO BUS 205 [SUB230       230.00] CKT 1
```

Figure 10.8. Overload Violation Report



```
E REPORT:
             CONTINGENCY   <-------- B U S --------->   V-CONT    V-INIT
       RANGE ISLAND 6         205 SUB230      230.00   0.92855   0.94902  1
       RANGE ISLAND 6         211 HYDRO_G     20.000   1.06388   1.04042  1
   DEVIATION OVRLOD 8        3007 RURAL       230.00   0.89387   0.96370  0
   DEVIATION OVRLOD 8        3008 CATDOG      230.00   0.87479   0.95861  0
   DEVIATION OVRLOD 8        3018 CATDOG_G    13.800   0.94251   1.02177  0
       RANGE OVRLOD 9         205 SUB230      230.00   0.92046   0.94902  1
       RANGE OVRLOD 9         211 HYDRO_G     20.000   1.06479   1.04042  1
       RANGE OVRLOD 11        205 SUB230      230.00   0.92564   0.94902  1
       RANGE OVRLOD 11        211 HYDRO_G     20.000   1.06082   1.04042  1
       RANGE OVRLOD 13        205 SUB230      230.00   0.92483   0.94902  1
       RANGE OVRLOD 13        211 HYDRO_G     20.000   1.07126   1.04042  1
   DEVIATION OVRLOD 13       3003 S. MINE     230.00   0.96142   1.02333  0
       RANGE OVRLOD 15        205 SUB230      230.00   0.92302   0.94902  1
       RANGE OVRLOD 15        211 HYDRO_G     20.000   1.06426   1.04042  1
       RANGE OVRLOD 16        205 SUB230      230.00   0.93671   0.94902  1
       RANGE OVRLOD 17        203 EAST230     230.00   0.93553   0.96651  1
       RANGE OVRLOD 17        205 SUB230      230.00   0.91571   0.94902  1
       RANGE OVRLOD 17        211 HYDRO_G     20.000   1.08727   1.04042  1
       RANGE OVRLOD 26        205 SUB230      230.00   0.93721   0.94902  1
       RANGE OVRLOD 26        211 HYDRO_G     20.000   1.06721   1.04042  1
       RANGE OVRLOD 28        205 SUB230      230.00   0.93955   0.94902  1
       RANGE OVRLOD 29        203 EAST230     230.00   0.93237   0.96651  1
       RANGE OVRLOD 29        205 SUB230      230.00   0.91483   0.94902  1

ND:
ENTS
EN LINE FROM BUS 101 [NUC-A        21.600] TO BUS 151 [NUCPANT      500.00]
EN LINE FROM BUS 102 [NUC-B        21.600] TO BUS 151 [NUCPANT      500.00]
EN LINE FROM BUS 201 [HYDRO        500.00] TO BUS 211 [HYDRO_G      20.000]
EN LINE FROM BUS 3001 [MINE        230.00] TO BUS 3011 [MINE_G       13.800
EN LINE FROM BUS 3008 [CATDOG      230.00] TO BUS 3018 [CATDOG_G     13.800
EN LINE FROM BUS 154 [DOWNTN       230.00] TO BUS 205 [SUB230       230.00]
EN LINE FROM BUS 153 [MID230       230.00] TO BUS 154 [DOWNTN       230.00]
EN LINE FROM BUS 153 [MID230       230.00] TO BUS 154 [DOWNTN       230.00]
EN LINE FROM BUS 3001 [MINE        230.00] TO BUS 3003 [S. MINE      230.00
EN LINE FROM BUS 203 [EAST230      230.00] TO BUS 205 [SUB230       230.00]
EN LINE FROM BUS 154 [DOWNTN       230.00] TO BUS 3008 [CATDOG      230.00]
EN LINE FROM BUS 3005 [WEST        230.00] TO BUS 3008 [CATDOG       230.00
EN LINE FROM BUS 152 [MID500       500.00] TO BUS 3004 [WEST        500.00]
EN LINE FROM BUS 153 [MID230       230.00] TO BUS 3006 [UPTOWN      230.00]
EN LINE FROM BUS 3005 [WEST        230.00] TO BUS 3006 [UPTOWN       230.00
EN LINE FROM BUS 3003 [S. MINE     230.00] TO BUS 3005 [WEST         230.00
EN LINE FROM BUS 3004 [WEST        500.00] TO BUS 3005 [WEST         230.00
EN LINE FROM BUS 3005 [WEST        230.00] TO BUS 3008 [CATDOG       230.00
EN LINE FROM BUS 3002 [E. MINE     500.00] TO BUS 3004 [WEST         500.00
EN LINE FROM BUS 3001 [MINE        230.00] TO BUS 3002 [E. MINE      500.00
EN LINE FROM BUS 152 [MID500       500.00] TO BUS 202 [EAST500      500.00]
EN LINE FROM BUS 154 [DOWNTN       230.00] TO BUS 203 [EAST230      230.00]
EN LINE FROM BUS 151 [NUCPANT      500.00] TO BUS 201 [HYDRO        500.00]
```

Figure 10.9. Voltage Violation Report

10.2. Substation Reliability Assessment

10.2.1. Overview

Substations are junctions of power exchanges between the generation and transmission systems or between the transmission and distribution systems. Substations are a critical part of a power system and play an important role in its reliability performance. The contribution of a substation to power system reliability can be measured in terms of the frequency and duration of substation related outage events that lead to violation of the power system performance criteria.

The substation reliability measures can be used for:

- comparing alternative substation/network configurations
- evaluating the sensitivity of the system performance to changes in equipment outage data
- evaluating the sensitivity of the system performance to equipment rating changes
- evaluating the sensitivity of the system performance to variations in load levels
- determining the impact of equipment maintenance on the system performance.

For substations that have been built using good design practices and quality equipment, the difference in reliability is primarily a function of the bus-breaker configuration. The selected substation bus-breaker scheme determines the electrical and physical arrangement of the equipment. Bus-breaker scheme selection must consider such factors as reliability, economy, safety, and simplicity, as warranted by the specific function and the relative importance of the substation in the overall power system. In general, designs for higher reliability tend to require more circuit breakers and hence lead to higher equipment costs. A few typical bus-breaker schemes are:

- Single bus
- Main and transfer bus
- Double bus, single breaker
- Ring bus
- Breaker and a half
- Double bus, double breaker .

10.2.2. Substation Reliability Assessment in PSS®E

The Substation Reliability Assessment (SRA) module in PSS®E can be used to assess the reliability of a given substation by calculating its power transfer capability under equipment fault or maintenance outage conditions. SRA can simulate single component and common mode faults or failures. A single component in the substation model can either be a bus section, a transformer, a line, a feeder, a circuit breaker, or a switch. Common mode refers to multiple components that fail simultaneously due to a common cause.

For each single component, three failure modes can be considered by SRA: fault, scheduled maintenance outage, and unscheduled maintenance outage. Scheduled maintenance means the planned or controlled removal of a component for inspection, overhaul, test, etc. The time of removal is controllable. Unscheduled maintenance means the unplanned removal of a component and the timing can be delayed for a few hours. For common mode, only faults are considered.

The state enumeration method discussed in Section 10.1, "Probabilistic Reliability Assessment" of this document is used in SRA. Each mode represents a state in the system state space. Furthermore, for each single component fault or common mode fault, SRA simulates the event in two states: post-fault and post-switching. Therefore, the number of system states increases rapidly with the number of components. Some measures are applied in SRA to limit the number of states included in the calculations:

1. Overlapping failure events are considered only up to the second order. In other words, combinations of up to only 2 events are considered.

2. Scheduled maintenance is not allowed as a secondary contingency. In other words, a scheduled maintenance will not be performed if another component within the substation has already been outaged due to a fault or another maintenance event.

3. Unscheduled maintenance is not allowed during the post-fault state of another component fault, but may be performed during the post-switching state.

4. Stuck breaker conditions (that is, failures of circuit breakers to operate to clear a fault when they are supposed to do so) are considered as sub-states (to be explained later in this section).

The reliability indices computed by SRA are the frequency and probability of the substation not meeting its load demand, the average interrupted power in MW/year and the expected energy not supplied in MWH/year. Definitions of these indices can be found in Section 10.1, "Probabilistic Reliability Assessment" of this document. These indices are computed for the substation as a whole as well as for each load point within the substation.

10.2.3. Substation Reliability Evaluation Procedures

The probability of a substation not meeting its load demand is the sum of the probabilities of all states that lead to loss of load. The assessment of the effect of a component failure state upon the maximum transfer capability of the substation is discussed below and the probability calculations are discussed later in this section.

For a component in the fault mode, the sequence of switching and assessment is modeled in SRA as follows:

1. Identify the location of the fault.

2. Operate breaker(s) to clear the fault.

3. Assess the effect on the substation. This is the Post-fault state.

4. Operate switch(es) to isolate the faulted component and, if appropriate, re-close breakers to minimize the extent of the effect on the substation. The Post-fault state in Step 3 persists until switching is completed in Step 4; the time to switching completion is S.

5. Assess the effect on the substation. This is the Post-switching state, which persists until component repair or replacement is completed in Step 6; the time to repair completion is R.

6. Reconfigure the system with the restored component.

Assessment of the effects on the substation includes a connectivity check and a calculation of the power transfer capability. SRA does not perform conventional power flow calculations, but uses a transportation network model (please refer to Ford-Fulkerson algorithm) to calculate the real power transfer capability.

10.2.4. Example of a Substation Reliability Assessment

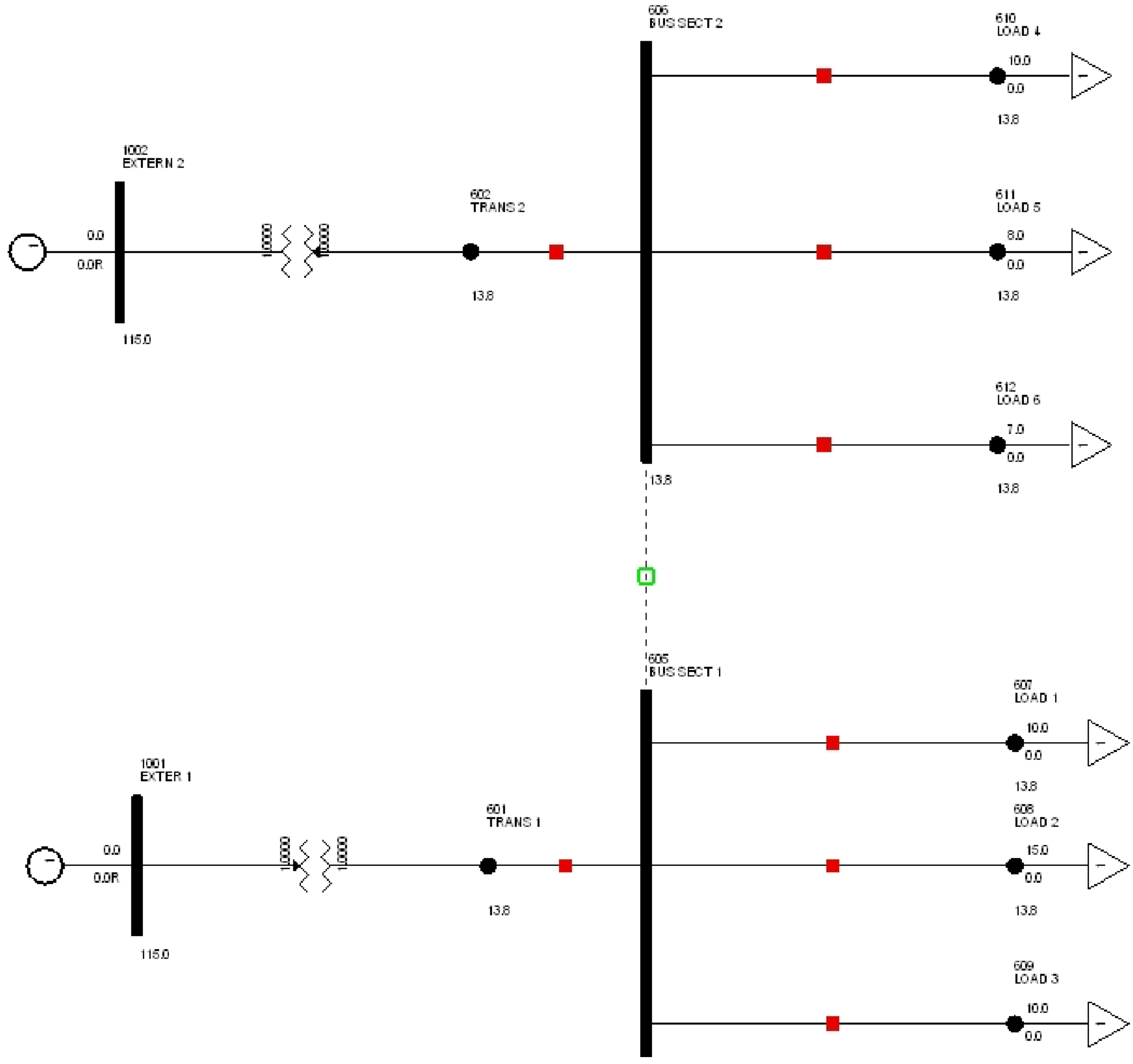


Figure 10.10. Example of a Simple Substation Configuration

An example of a substation, providing supply to six loads, is shown in Figure 10.10, “Example of a Simple Substation Configuration”. This substation has a normally open tie breaker between buses 605 and 606. Two source buses, 1001 and 1002, which are modeled as Type 3 system swing buses, represent the external power system with infinite sources. Sink buses 607 to 612 supply the substation loads.

One of the possible component failures considered in the analysis is a fault on the two-winding transformer between bus 601 and bus 1001. According to the procedures described above, the sequence of switching simulation and effect assessment for this fault is as follows:

1. The fault is located at the two-winding transformer between bus 601 and bus 1001
2. The fault is isolated by opening the breaker between bus 601 and bus 606. Any breaker connected to the external system is assumed to be automatically opened also. A connectivity check is performed, which shows that buses 601 and 1001 are isolated from the rest of the substation. Also, because the tie breaker between buses 605 and 606 is normally open, buses 605, 607, 608 and 609 are separated from the source and all their loads are interrupted. This represents the post-fault state which persists until all switching operations described in the next step are completed.
3. The switches or disconnects at the breaker between 601 and 605 are then opened, which does not change the status of buses 601 and 1001. At the same time, the tie breaker between buses 605 and 606 is closed. This condition is the post-switching state that persists until repair of the faulted transformer is complete.
4. A connectivity check at the post-switching state is performed, which finds that all loads are now connected to the source at bus 1002. The active power transfer through the substation is calculated using a transportation network algorithm, which finds that the limiting element is the two-winding transformer between bus 602 and bus 1002. The difference between the specified rating of the transformer and the total desired load at buses 607 to 612 is the amount of load interrupted in the post-switching state.

In the power transfer capability assessment, the MW values of the loads and the MVA ratings of the branches (adjusted by a user-defined multiplier) are used in the branch flow and load curtailment calculations. Branch impedances, reactive power flows, voltage magnitudes and angles are ignored.

For each component fault simulated, the reliability analysis is repeated by assuming that one of the breakers that are supposed to isolate the fault fails to operate. In this example, the breaker between bus 601 and bus 605 is assumed to be stuck. The sequence of simulated events is as follows:

1. The fault is located at the two-winding transformer between bus 601 and bus 1001.
2. Since the breaker between bus 601 and bus 605 fails to operate, the breakers between buses 605 and 607, between buses 605 and 608 and between buses 605 and 609 will have to be opened to isolate the faulted transformer. As before, the loads at buses 607, 608 and 609 are interrupted in the post-fault state.
3. The faulted transformer is isolated by opening the switches at the breaker between buses 601 and 605. Since bus 605 is now separated from the faulted transformer, the breakers between buses 605 and 607, between buses 605 and 608 and between buses 605 and 609 can be closed. Also, the normally open tie breaker between buses 605 and 606 is closed to connect bus 605 with the rest of the substation. The post-switching state persists until component repair is completed;
4. All loads are now connected to the source bus at 1002, but the substation's power transfer capability is again limited by the transformer between buses 1002 and 602. The amount of load interrupted is identical to that computed during the post-switching state of the transformer fault without the stuck breaker condition.

10.2.5. Frequency and Probability Calculations

A failure event considered in SRA can either be a single contingency or a combination of a primary and a secondary contingency. Each contingency can consists of one or more outaged components. Section 11 of this document discusses the calculation of the frequency and probability of a single component outage represented by a two-state model: in service and out of service. In SRA, a component fault is represented by a three-state model, as described below.

Single Contingency

The outage statistics of the components to be considered in the study are defined in the Outage Statistics Data File. For example, the component fault data are given by:

Component fault frequency	= F, in occurrences per year
Component repair time	= Dr, in hours

For a single component fault:

Post-fault frequency	= F
Post-fault duration	= Ds
Post-fault probability, Ps	= F x D_s
Post-switching frequency	= F
Post-switching duration	= D_r
Post-switching probability, Pr	= F x D_r

where Ds is the switching time, in hours, required to perform the appropriate switching actions in order to reduce the impact of the fault upon the substation. The switching time is an input value which is assumed to be identical for all faults considered in a study.

Stuck Breaker Event

For a component fault accompanied by a stuck breaker condition:

Post-fault frequency	= F * Pstuck
Post-fault probability	= Ps * Pstuck
Post-fault duration	= probability / frequency = Ps / F = Ds
Post-switching frequency	= F * P_{stuck}
Post-switching probability	= P_r * P_{stuck}
Post-switching duration	= probability / frequency = P_r / F = D_r

where P_{stuck} is the probability of a stuck breaker.

Overlapping Contingency

The repair and failure rates of the components are assumed to be constant, and the initiations of the primary and secondary contingencies are assumed to be statistically independent. With these assumptions, Markov equations can be used to compute the state probabilities. The Markov method is sometimes called the state space method, since it is based on the state space diagram.

Figure 10.11, “State Transition Diagram for First Contingency Fault, Second Contingency Fault” is an example of a state space diagram for an independent overlapping contingency with fault A occurring as a primary contingency and fault B as a secondary contingency. All states and the transitions among them are shown in the diagram. Since each fault is represented by a three-state model, consideration is given to the switching status of the primary contingency at the time of the secondary contingency. Given a primary contingency fault, a secondary contingency fault may occur either during the post-fault or the post-switching state of the primary fault, the risk of each event being proportional to its exposure.

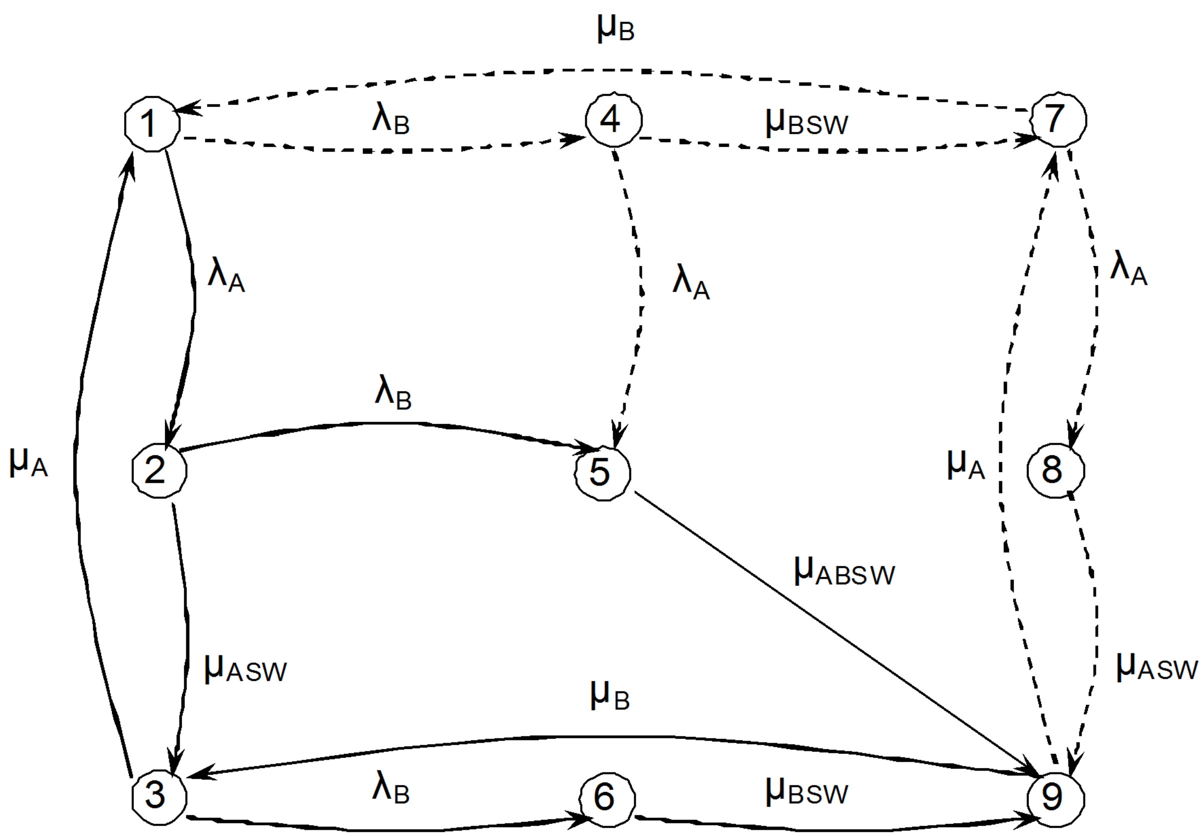


Figure 10.11. State Transition Diagram for First Contingency Fault, Second Contingency Fault

The states in Figure 10.11, “State Transition Diagram for First Contingency Fault, Second Contingency Fault” are enumerated as follows:

- State 1 represents the normal state when both A and B are in service.
- State 2 is the post-fault state of fault A.
- State 3 is the post switching state of fault A.
- State 4 is the post-fault state of fault B.
- State 5 is the post-fault state of fault A and the post-fault state of fault B
- State 6 is the post-fault state of fault B during the post-switching state of fault A

- State 7 is the post-switching state of fault B.
- State 8 is the post-fault state of fault A during the post-switching state of fault B.
- State 9 is the post-switching stage of fault A and the post-switching state of fault B.

The following symbols are used in the diagram:

λ_A, λ_B are the failure rates of A and B, respectively.

μ_A and μ_B are the repair rates of A and B, respectively.

D_A and D_B are the durations of A and B, respectively, from the time of fault initiation to repair completion.

μ_{ASW} and μ_{BSW} are the switching rates of primary and secondary faults A and B, respectively.

μ_{ABSW} is the switching rate of the combined contingency.

Since all switching times are assumed to be identical in the study,

$1 / \mu_A + 1 / \mu_{ASW} = D_A$

$1 / \mu_B + 1 / \mu_{BSW} = D_B$

Other basic assumptions are:

$\lambda_A << \mu_A << \mu_{ASW}$

$\lambda_B << \mu_B << \mu_{BSW}$

For example, in State 5, the secondary fault (either B or A) occurs before switching is completed for the primary fault (either A or B). Hence, the appropriate circuit breakers for clearing both faults are assumed to have opened. The equations for this state are:

Duration	= DS
Frequency	$= F_B * P_A * D_S / D_A$
Probability	$= (F_B * P_A * D_S / D_A)*D_S$

Where

DS is switching time,

FA and FB are the frequencies of fault A and B, respectively

PA and PB are the probabilities of fault A and B, respectively.

State 6 represents the secondary fault B occurring after switching operations have been completed for primary fault A. The equations for this state are:

Duration	= DS
Frequency	$= F_B * P_A * [D_A - D_S] / D_A$

Probability	$= (F_B * P_A * [D_A - D_S] / D_A) * D_S$

State 9 represents the condition when the switching operations for both primary and secondary faults have been completed. The equations for this state are:

Duration	$= (D_A - D_S) * (D_B - D_S) / ([D_A - D_S] + [D_B - D_S])$
Frequency	$= F_B * P_A$
Probability	$= F_B * P_A * (D_A - D_S) * (D_B - D_S) / ([D_A - D_S] + [D_B - D_S])$

10.2.6. Maintenance Outages

There are two types of maintenance outages modeled in SRA: scheduled and unscheduled maintenance, which are represented as a two-state model in SRA. Both of them can be a primary contingency, but only an unscheduled maintenance outage can be a secondary contingency in an overlapping contingency.

The outage statistics of maintenance outages of the components are defined in the Outage Statistics Data File in the form of:

Maintenance outage frequency	= F, in occurrences per year
Maintenance outage duration	= D, in hours
Maintenance outage probability	= F * D

Similarly frequency and probability of an overlapping contingency that consists of one maintenance outage could be derived with Markov equations. Figure 10.12, "State Transition Diagram for First Contingency Unscheduled Maintenance Outage, Second Contingency Fault" shows the state space diagram of an overlapping contingency with an unscheduled maintenance outage as the primary contingency and a fault as the secondary contingency. Note that for State 6 in Figure 10.11, "State Transition Diagram for First Contingency Fault, Second Contingency Fault", the breaker operations to clear the secondary fault B and the switching operations after primary fault A result in a network topology that is equivalent to the one produced by the secondary fault B occurring during unscheduled maintenance of component A. Therefore, the sate space diagram of the overlapping contingency with an unscheduled maintenance outage as the primary contingency and a fault as the secondary contingency can be obtained by removing all post-fault states of the fault A in the Figure 10.11, "State Transition Diagram for First Contingency Fault, Second Contingency Fault".

The states in Figure 10.12, "State Transition Diagram for First Contingency Unscheduled Maintenance Outage, Second Contingency Fault" are enumerated as follows:

- State 1 represents the normal state when both A and B are in service.
- State 2 is the down state of component A.
- State 3 is the post-fault state of fault B during the down state of component A.
- State 4 is the down state of component A and the post-switching state of fault B.
- State 5 is the post-fault state of fault B.
- State 6 is the post-switching state of fault B.

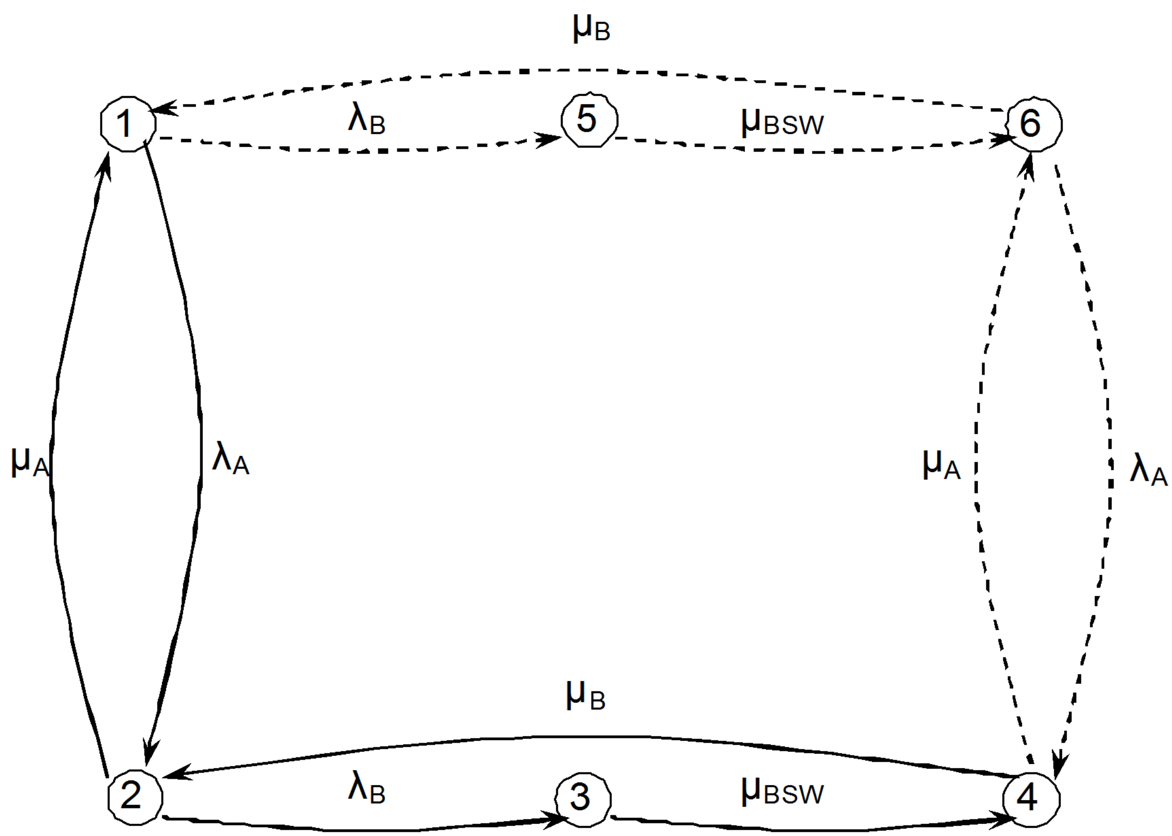


Figure 10.12. State Transition Diagram for First Contingency Unscheduled Maintenance Outage, Second Contingency Fault

In State 3, the secondary fault B occurs during the unscheduled maintenance outage of component A and circuit breakers for clearing fault B are assumed to have opened. The equations for this state are:

Duration	= DS
Frequency	= F_B * P_A
Probability	= (F_B * P_A) * D_S

Where

DS is switching time,

FA and FB are the frequencies of unscheduled maintenance outage of component A and secondary fault B, respectively

PA and PB are the probabilities of unscheduled maintenance outage of component A and secondary fault B, respectively.

State 4 represents the condition when component A is out-of-service and switching operations have been completed for fault B. The equations for this state are:

Duration	$= (D_B - D_S) * D_A / ([D_B - D_S] + D_A)$
Frequency	$= F_B * P_A$
Probability	$= (F_B * P_A) * (D_B - D_S) * DA / ([D_B - D_S] + D_A)$

10.3. Corrective Action Analysis

There may be operation limit violations such as flow overloading, bus voltage outside an acceptable range when subject to a contingency case. The objective of corrective action analysis is to find a set of corrective actions by which the system condition is restored to comply with operation limits. Corrective action analysis is required in reliability assessment where probabilistic indices are calculated, such as duration of loss of load, to model a complete sequence from the outage to the complete restoration to a security condition. Corrective action analysis is modeled as an optimal power flow with the objective of minimizing control adjustments subject to operation limits. The Optimization technique is discussed in Chapter 14 of the *PSS®E Program Operation Manual*. Compared to PSS®E OPF, it does not need to set up complete OPF data sheets, but gets data from two files, Subsystem Description Data File and Monitored Element Data File, which are used in contingency analysis, and uses linear programming technique instead of non-linear programming.

10.3.1. Successive Linear Programming Method

The optimal power flow problem for corrective action analysis comprises non-linear power flow equations as equality constraints, therefore the problem is a non-linear problem. The system must be linearized under current operation condition to set up a Linear Programming model. To handle the errors introduced by linearization, a successive solution technique is applied to AC corrective action analysis. The Successive Linear Programming (SLP) based corrective actions consist of five steps:

1. Determine voltage limit violations and overloads for a power flow case; and linearize power system network and set up a Linear Programming problem
2. Compute sensitivities for the worst overload and voltage violations
3. Choose the worst violation as one constraint added to a Linear Programming formulation and solve the new optimization problem
4. Inner loop - update power flow solution linearly and check for possibly more violations, go back to step 2
5. Major loop - back to step 1 to update nonlinear AC power flow solution after corrective actions, and verify if violations are resolved.

The successive linear programming has been chosen because of its speed and computational reliability. The LP computational burden of the optimization part is significantly reduced in that the nonlinear power system network equations are not dealt with explicitly in the Linear Programming, but handled by the AC power flow solution. In addition, the Linear Programming has the ability to quickly identify infeasibility conditions during its solution process. Therefore, infeasibility relaxation schemes can be implemented efficiently.

The Successive Linear Programming handles the local control adjustments such as tap and shunt adjustments and generation voltage controls in the AC power flow. This implementation uses the AC power flow part to address local objectives as specified in a power flow case, relax limits on local controls such as the generator voltage controls, bus type changes due to Var limit, etc. Thus, the algorithm deals with power flow adjustments during optimization in a way that is consistent with adjustment models used in standard AC power flow solutions. All local control adjustments made by the SLP will, therefore, be consistent with the results of a manual process whereby you implement corrective actions and then run AC power flows with local control adjustments enabled.

10.3.2. Modeling Corrective Actions

The objective function of corrective action analysis is to minimize the control adjustments subject to equality constraints, namely power flow equations, and inequality constraints such as limits of controls and operation condition limits on branch flows and bus voltages. The form of objective function is fixed, while weighted costs of control adjustments in the objective function are given by their cost functions specified by users. The optimal power flow problem for corrective action analysis is modeled in the following form:

$$\min F = \sum_{i=1}^{N} (C_i \Delta U_i)$$

where: C_i is the cost factor of the i^{th} control; ΔU_i is the control adjustment and N is the number of controls.

Subject to:

Power flow equations: G(U,V)=0

Vmax ≥ V ≥ Vmin

Umax ≥ U ≥ Umin

Where: Vmax and Vmin are upper and lower limits of operation conditions; Umax and Umin are upper and lower limits of controls

The non-linear model is converted to a standard form of Linear Programming method as following:

minF = cx

Subject to:

Ax = b

x ≥ 0

where A is referred to coefficient matrix. The corrective action analysis starts with a converged power flow case relative to which the power system model is linearized to calculate the coefficient matrix to build the Linear Programming problem. The c is the factor vector and x is the vector that contains independent variable or control variables and dependent variables such as voltages and flows.

10.3.3. Constraints and Controls

The corrective action algorithm recognizes several types of constraints and controls. Power flow equations are always included as equality constraints. Inequality constraints define lower and upper limits on a variable. including operation limits imposed on bus voltages, branch flows, or power transfers over interfaces, and limits of controls such as active power generation limits. The system problems identified in a contingency analysis are the violations of such constraints. Monitored buses and their limits are specified in Contingency Description Data File; voltage range limits are taken into account in corrective actions while voltage deviation limits are ignored. Monitored branches are specified in Contingency Description Data File too; the rating set and percent of rating set will be specified prior to running corrective action analysis. Only monitored elements and their limits are considered as constraints in corrective action analysis. Operation limits such as bus voltage constraints are introduced as soft limits in the form of multi-segment linear functions.

Controls, such as generator active powers, phase shifter angles, and bus load curtailments, are independent variables that can be adjusted to arrive at a best solution with respect to the given objective. Constraints of controls are always treated as hard limits. This priority order is maintained by assigning a higher cost to the lower priority controls; the lower priority controls are discouraged from being adjusted due to high costs introduced into the objective for the same amount of adjustments. Internally, the priorities of control actions are: phase shifter angle adjustment, generator active power shift, and load curtailment. The cost functions are V curves for generation dispatch and phase shifter angle adjustment, and linear functions for load curtailment. Especially when generator active power adjustments are available in corrective actions, a balance constraint is automatically introduced into the LP problem, so the unbalance between generation resource and demand caused by corrective actions is allocated on controlled generators, but not totally observed by the swing bus.

10.3.4. Examples

```
MONITOR BRANCHES
3004 152
3006 153
3008 154
 201 151
 202 152
 203 154
 205 154
3001 3002
3004 3005
3005 3008
3008 3018
END
MONITOR INTERFACE WEST RATING 200 MW
3004 152
3006 153
3008 154
END
MONITOR INTERFACE EAST RATING 350 MW
201 151
202 152
203 154
205 154
END
MONITOR VOLTAGE RANGE BUS 3001 0.95 1.05
MONITOR VOLTAGE RANGE AREA 2    0.94 1.06
MONITOR VOLTAGE DEVIATION ZONE 5 0.06 0.055
END
```

Figure 10.13. Monitored Element Data File for savnw

Corrective action analysis is carried out on the savnw.sav case. The system diagram and data are shown in Figure 19-3 in the *PSS ® E* Program Operation Manual. In the system, there are six generators and one phase shifter from bus 202 to bus 203 included in the control list; the load curtailment control is disabled. The constraints are defined in the Monitored Element Data File savnw.mon as presented in Figure 10.13, "Monitored Element Data File for savnw". The voltage deviation limit in the file is ignored from corrective action analysis. The rating set and percent of rating set are Rating A and 70 percent of Rating A specified prior to running corrective action analysis.

The examples in Figure 10.14, "Corrective Action Solution with 0.1 and 1.0 for Generation Shift and Phase Shifter Angle Adjustment, Respectively" and Figure 10.15, "Corrective Action Solution with 1.0 and 0.1 for Generation Shift and Phase Shifter Angle Adjustment, Respectively" show impacts of weighting factors on corrective action solutions. The solution in Figure 10.14, "Corrective Action Solution with 0.1 and 1.0 for Generation Shift and Phase Shifter Angle Adjustment, Respectively" is obtained by setting 0.1 for weight of generation dispatch and 1.0 for weight of phase shifter angle adjustment. In this case huge amount of generation is shifted from generator buses 206 to 3011 to relieve the overloads on line 154 to 203 and 154 to 205; while the phase shifter adjustment associated with a high cost is relatively small.

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  BASE CASE OVERLOAD REPORT: MONITORED BRANCHES LOADED ABOVE  70.0 % OF RATING SET A
  INCLUDES BUS VOLTAGE VIOLATION REPORT

  <---------- O V E R L O A D E D   L I N E S ---------->     FLOW    RATING        %
  <------ F R O M --------> <-------- T O ----------> CKT   MVA/MW     MVA
     154*DOWNTN       230.00    203 EAST230      230.00  1     133.7     200.0    71.22
     154*DOWNTN       230.00    205 SUB230       230.00  1     434.4     600.0    77.11
    3008 CATDOG       230.00   3018*CATDOG_G     13.800  1     128.1     150.0    85.38
  WEST                                                        147.0     200.0    73.48

 ---------------------------------------------------------------------------------

  POST-CORRECTIVE ACTIONS OVERLOAD REPORT/ INCLUDES BUS VOLTAGE VIOLATION REPORT

  <---------- O V E R L O A D E D   L I N E S ---------->     FLOW    RATING        %
  <------ F R O M --------> <-------- T O ----------> CKT   MVA/MW     MVA
     154*DOWNTN       230.00    203 EAST230      230.00  1     131.6     200.0    70.27
     154*DOWNTN       230.00    205 SUB230       230.00  1     396.8     600.0    70.64
    3008 CATDOG       230.00   3018*CATDOG_G     13.800  1     106.7     150.0    71.13

 ---------------------------------------------------------------------------------

  BUSES WITH REAL POWER GENERATION ADJUSTMENTS (MW)
  <-------- B U S --------->    GEN-INI    GEN-NEW    GEN-ADJ
     206 URBGEN       18.000      800.0      717.7      -82.3         Control adjustments
    3011 MINE_G       13.800      258.7      371.3      112.6
    3018 CATDOG_G     13.800      100.0       70.6      -29.4

  PHASE SHIFTER ADJUSTMENTS (DEGREE)
  <----------- P H A S E   S H I F T E R -----------> CKT   PHASE-INI PHASE-NEW PHASE-ADJ
     203 EAST230      230.00    202 EAST500      500.00  1       0.00      0.66      0.66

  ===== END OF REPORT ====================================================================
```

Figure 10.14. Corrective Action Solution with 0.1 and 1.0 for Generation Shift and Phase Shifter Angle Adjustment, Respectively

The results in Figure 10.15, "Corrective Action Solution with 1.0 and 0.1 for Generation Shift and Phase Shifter Angle Adjustment, Respectively" are obtained by setting 1.0 for weight of generation dispatch and 0.1 for weight of phase shift angle adjustment contrary to the above example. The phase shifter angle is increased to 8.89 as a main adjustment strategy to relieve overloads on two transmission lines from 154 to 203 and from 154 to 205. Overload on 3008 to 3018 can be relieved only by generation reduction of the generator at bus 3008, and generation should be dispatched up at bus 3011 to balance generation resource and demand. The optimal solutions in this case will be involved generation dispatch and phase shifter adjustments.

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  BASE CASE OVERLOAD REPORT: MONITORED BRANCHES LOADED ABOVE  70.0 % OF RATING SET A
  INCLUDES BUS VOLTAGE VIOLATION REPORT

  <---------- O V E R L O A D E D   L I N E S ---------->    FLOW   RATING        %
  <------ F R O M --------> <-------- T O ----------> CKT   MVA/MW    MVA
     154*DOWNTN      230.00    203 EAST230      230.00  1     133.7   200.0    71.22
     154*DOWNTN      230.00    205 SUB230       230.00  1     434.4   600.0    77.11
    3008 CATDOG      230.00   3018*CATDOG_G     13.800  1     128.1   150.0    85.38
  WEST                                                        147.0   200.0    73.48

 --------------------------------------------------------------------------------

  POST-CORRECTIVE ACTIONS OVERLOAD REPORT/ INCLUDES BUS VOLTAGE VIOLATION REPORT

  BUSES WITH LOW/HIGH VOLTAGE VIOLATIONS:
  <-------- B U S --------> V-CORR  V-MAX  V-MIN
     205 SUB230      230.00 0.9389 1.0600 0.9400

  <---------- O V E R L O A D E D   L I N E S ---------->    FLOW   RATING        %
  <------ F R O M --------> <-------- T O ----------> CKT   MVA/MW    MVA
    3008 CATDOG      230.00   3018*CATDOG_G     13.800  1     105.1   150.0    70.07
  WEST                                                        140.1   200.0    70.07

 --------------------------------------------------------------------------------

  BUSES WITH REAL POWER GENERATION ADJUSTMENTS (MW)                 Control adjustments
  <-------- B U S -------->    GEN-INI   GEN-NEW   GEN-ADJ
     206 URBGEN      18.000     800.0     798.8     -1.2
    3011 MINE_G      13.800     258.7     283.2     24.5
    3018 CATDOG_G    13.800     100.0      68.2    -31.8

  PHASE SHIFTER ADJUSTMENTS (DEGREE)
  <----------- P H A S E   S H I F T E R -----------> CKT  PHASE-INI PHASE-NEW PHASE-ADJ
     203 EAST230     230.00    202 EAST500      500.00  1       0.00      8.89      8.89

  ===== END OF REPORT ===================================================================
```

Figure 10.15. Corrective Action Solution with 1.0 and 0.1 for Generation Shift and Phase Shifter Angle Adjustment, Respectively

The Linear programming problem is set up with respect to current system operation condition. The errors introduced by linearization of the system models are removed by the SLP method. The optimal set of corrective actions of the LP problem is applied to adjust the working case and a full AC power flow solution on the modified case is done to verify whether all violations are resolved. The process continues until an optimal solution is reached or the number of iterations reaches its limit. The examples as presented in Figure 10.16, "Corrective Action Solution after 1 Power Flow", Figure 10.17, "Corrective Action Solution after 2 Power Flows" and Figure 10.18, "Corrective Action Solution after 3 Power Flows" show results with different numbers of iterations for main loop in SLP method. The numbers of AC power flows are 1, 2 and 3 respectively. The external weighting factors use default values of 1.0. The cost factors used in the objective functions are then 0.02 per degree for phase shifter angle adjustment and 0.01 per MW for generation dispatch. Violations are not resolved after the first iteration as shown in Figure 10.16, "Corrective Action Solution after 1 Power Flow"; an optimal solution has not been arrived after two iterations. The final optimal solution is shown in Figure 10.18, "Corrective Action Solution after 3 Power Flows". The values of objective functions at each step are 1.4943, 1.38825 and 0.94 respectively.

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--------------------------------------------------------------------------------

 BASE CASE OVERLOAD REPORT: MONITORED BRANCHES LOADED ABOVE  70.0 % OF RATING SET A
 INCLUDES BUS VOLTAGE VIOLATION REPORT

 <---------- O V E R L O A D E D   L I N E S ---------->     FLOW   RATING       %
 <------ F R O M --------> <-------- T O ----------> CKT   MVA/MW     MVA
    154*DOWNTN      230.00     203 EAST230      230.00  1    133.7    200.0    71.22
    154*DOWNTN      230.00     205 SUB230       230.00  1    434.4    600.0    77.11
   3008 CATDOG      230.00    3018*CATDOG_G     13.800  1    128.1    150.0    85.38
 WEST                                                        147.0    200.0    73.48

--------------------------------------------------------------------------------

 POST-CORRECTIVE ACTIONS OVERLOAD REPORT/ INCLUDES BUS VOLTAGE VIOLATION REPORT

 <---------- O V E R L O A D E D   L I N E S ---------->     FLOW   RATING       %
 <------ F R O M --------> <-------- T O ----------> CKT   MVA/MW     MVA
    154*DOWNTN      230.00     205 SUB230       230.00  1    396.7    600.0    70.64
   3008 CATDOG      230.00    3018*CATDOG_G     13.800  1    106.5    150.0    71.02

--------------------------------------------------------------------------------

 BUSES WITH REAL POWER GENERATION ADJUSTMENTS (MW)
 <-------- B U S -------->    GEN-INI    GEN-NEW    GEN-ADJ
    206 URBGEN      18.000      800.0      744.8      -55.2
   3011 MINE_G      13.800      258.7      344.4       85.8
   3018 CATDOG_G    13.800      100.0       70.3      -29.7

 PHASE SHIFTER ADJUSTMENTS (DEGREE)
 <----------- P H A S E   S H I F T E R -----------> CKT  PHASE-INI PHASE-NEW PHASE-ADJ
    203 EAST230     230.00     202 EAST500      500.00  1       0.00      2.58      2.58

 ===== END OF REPORT ===================================================================
```

Violations are not removed.

Figure 10.16. Corrective Action Solution after 1 Power Flow

```
---------------------------------------------------------------------------------

 BASE CASE OVERLOAD REPORT: MONITORED BRANCHES LOADED ABOVE  70.0 % OF RATING SET A
 INCLUDES BUS VOLTAGE VIOLATION REPORT

 <---------- O V E R L O A D E D   L I N E S ----------->    FLOW    RATING        %
 <------ F R O M --------> <-------- T O ----------> CKT   MVA/MW      MVA
    154*DOWNTN      230.00    203 EAST230     230.00  1     133.7    200.0    71.22
    154*DOWNTN      230.00    205 SUB230      230.00  1     434.4    600.0    77.11
   3008 CATDOG      230.00   3018*CATDOG_G    13.800  1     128.1    150.0    85.38
 WEST                                                       147.0    200.0    73.48

---------------------------------------------------------------------------------

 POST-CORRECTIVE ACTIONS OVERLOAD REPORT/ INCLUDES BUS VOLTAGE VIOLATION REPORT

 <---------- O V E R L O A D E D   L I N E S ----------->    FLOW    RATING        %
 <------ F R O M --------> <-------- T O ----------> CKT   MVA/MW      MVA
    154*DOWNTN      230.00    205 SUB230      230.00  1     392.9    600.0    70.11
   3008 CATDOG      230.00   3018*CATDOG_G    13.800  1     105.1    150.0    70.08

---------------------------------------------------------------------------------

 BUSES WITH REAL POWER GENERATION ADJUSTMENTS (MW)
 <-------- B U S --------->    GEN-INI    GEN-NEW    GEN-ADJ
    206 URBGEN      18.000      800.0      772.1      -27.9
   3011 MINE_G      13.800      258.7      319.9       61.3
   3018 CATDOG_G    13.800      100.0       68.2      -31.8

 PHASE SHIFTER ADJUSTMENTS (DEGREE)
 <----------- P H A S E   S H I F T E R -----------> CKT  PHASE-INI PHASE-NEW PHASE-ADJ
    203 EAST230     230.00    202 EAST500     500.00  1        0.00      5.15      5.15

 ===== END OF REPORT ==================================================================
```

The corrective action solution is not optimal

Figure 10.17. Corrective Action Solution after 2 Power Flows

```
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 BASE CASE OVERLOAD REPORT: MONITORED BRANCHES LOADED ABOVE  70.0 % OF RATING SET A
 INCLUDES BUS VOLTAGE VIOLATION REPORT

 <---------- O V E R L O A D E D   L I N E S ---------->     FLOW   RATING       %
 <------ F R O M --------> <-------- T O ----------> CKT   MVA/MW    MVA
    154*DOWNTN      230.00     203 EAST230     230.00   1     133.7   200.0    71.22
    154*DOWNTN      230.00     205 SUB230      230.00   1     434.4   600.0    77.11
   3008 CATDOG      230.00    3018*CATDOG_G    13.800   1     128.1   150.0    85.38
 WEST                                                         147.0   200.0    73.48

 ---------------------------------------------------------------------------------

 POST-CORRECTIVE ACTIONS OVERLOAD REPORT/ INCLUDES BUS VOLTAGE VIOLATION REPORT

 <---------- O V E R L O A D E D   L I N E S ---------->     FLOW   RATING       %
 <------ F R O M --------> <-------- T O ----------> CKT   MVA/MW    MVA
    154*DOWNTN      230.00     205 SUB230      230.00   1     391.9   600.0    70.09
   3008 CATDOG      230.00    3018*CATDOG_G    13.800   1     105.1   150.0    70.08
 WEST                                                         140.1   200.0    70.03

 ---------------------------------------------------------------------------------

 BUSES WITH REAL POWER GENERATION ADJUSTMENTS (MW)
 <--------- B U S --------->    GEN-INI    GEN-NEW    GEN-ADJ
    206 URBGEN      18.000       800.0      796.9       -3.1
   3011 MINE_G      13.800       258.7      294.0       35.3
   3018 CATDOG_G    13.800       100.0       68.2      -31.8

 PHASE SHIFTER ADJUSTMENTS (DEGREE)
 <----------- P H A S E   S H I F T E R -----------> CKT  PHASE-INI PHASE-NEW PHASE-ADJ
    203 EAST230     230.00     202 EAST500     500.00   1       0.00      7.03      7.03

 ===== END OF REPORT ==================================================================
```

The optimal solution is found

Figure 10.18. Corrective Action Solution after 3 Power Flows

Chapter 11
Fault Analysis

11.1. Fault Analysis Overview

Fault analysis in PSS®E is based on a symmetrical component system representation and treated as a direct extension of the power flow activity group. The positive-sequence system model as established in power flow work is used directly in fault analysis. The negative- and zero-sequence system representations for fault analysis work are established simply by appending negative- and zero-sequence parameter values to the parameter lists describing the system for power flow purposes. The working file always includes provision for negative- and zero-sequence parameters of *every* system component. This data may be introduced at any time, and when introduced, data is saved and retrieved by activities SAVE and CASE as an integral part of a saved case.

PSS®E includes two separate and complementary fault analysis subsystems. The first, using the activities listed in Table 11.1, "Activities for Detailed Fault Analysis", is intended for detailed analysis of complicated unbalanced situations; it presents a complete system solution and overall system-oriented output comparable to that of a power flow. The second subsystem uses the activities listed in Table 11.2, "Activities for Single Fault Analysis at a Sequence of Buses" and is intended for the more routine work of examining simple ground faults at a large number of system locations.

Table 11.1. Activities for Detailed Fault Analysis

RESQ	Reads fault analysis data into working case.
SQLI	Lists fault analysis data from working case.
SQEX	List fault analysis data at a bus.
SQCH	Changes fault analysis data in working case.
SEQD	Prepares detailed positive-, negative-, and zero-sequence network models for interconnection and solution.
SCMU	Interconnects and solves three sequence networks under unbalanced conditions.
SCOP	Detailed output of unbalanced system conditions.

Table 11.2. Activities for Single Fault Analysis at a Sequence of Buses

RESQ	Reads fault analysis data into working case.
SQLI	Lists fault analysis data from working case.
SQEX	List fault analysis data at a bus.
SQCH	Changes fault analysis data in working case.
CONG	Converts generators to t^+ sources using impedance, ZSORCE, to characterize generators.
CONG,SQ	Converts generators to t^+ sources using impedance, ZPOS, to characterize generators.
ASCC	Automatically sequences fault analyses over all buses in a specified subsystem, for L-G and three-phase faults only.

Both fault analysis subsystems use the same system model setup procedures. These are described in Section 11.2, "System Modeling for Fault Analysis". Section 11.3, "Detailed Fault Analysis Calculations" covers the application of the detailed fault analysis activities to the three-sequence system model in the working file, and Section 11.4, "Scanning Short Circuit Analysis" covers the application of the simplified analysis activity ASCC, to the same model.

11.2. System Modeling for Fault Analysis

11.2.1. Philosophy

The system being studied is modeled by three symmetrical component sequence networks based on the positive-, negative-, and zero-sequence parameters of the three-phase power system elements. The s of the system, the positive-sequence parameters of all components (except generators in some cases), and the pre disturbance system conditions, are all taken from the power flow saved case. Fault analyses may be made with the same level of system modeling as used in a power flow study. Specifically, fault analyses may do the following:

- Recognize both reactance and resistance and include all actual shunt branches and line charging in the three sequence networks.
- Recognize both the magnitude ratio and phase shift of all transformers, including the inherent shift of delta-wye transformers if it is entered in the power flow data.
- Recognize the actual spread of internal voltage magnitude and phase angle of generators as initialized from a solved power flow case.
- Recognize loads by converting them to equivalent constant shunt admittance.

The level of system modeling detail used in a fault analysis calculation is controlled by manipulating the positive-sequence (or power flow) data in the working file into the required form before commencing fault analysis work. The detailed fault analyses activities described in Section 11.3, "Detailed Fault Analysis Calculations" always operate on the assumption that the system is modeled in the highest level of detail. In these activities, results corresponding to a simplified modeling basis are obtained if appropriate elements of data have null values, simplified calculating algorithms are not used, and, correspondingly, no computing time advantage is gained by simplifying the system model. The scanning short circuit analysis activities described in Section 11.4, "Scanning Short Circuit Analysis" operate on the assumption that system modeling will most often be at a low level of detail. These activities can calculate either on the basis of full detail or a faster algorithm that recognizes only a minimum level of detail.

11.2.2. Fault Analysis Data

The overriding principle of fault analysis data management in PSS®E is that the modeling detail and component status information is dictated by the positive-sequence model. Negative- and zero-sequence data values are held in the working case only where their values are different from the corresponding positive-sequence values. In setting up the negative and zero-sequence networks, PSS®E assumes the following:

1. All transmission branches (lines and transformers) have the same impedance, charging, and line-connected shunt characteristics in the negative-sequence as in the positive-sequence.
2. All transformers have phase shift in the negative-sequence equal and opposite to that in the positive-sequence.
3. All zero-sequence branches, both transmission branches, line-connected shunts, and bus connected shunts are assumed to have infinite zero-sequence impedance unless a different value is entered specifically via activities RESQ or SQCH.
4. All constant MVA and constant current load specified in the positive-sequence data are converted automatically to constant shunt admittance in the positive-sequence network.

5. All loads are automatically represented by the same shunt admittance in the negative-sequence as in the positive-sequence unless a different negative-sequence shunt admittance is entered specifically via activities RESQ or SQCH.

6. Loads are open circuits in the zero-sequence unless represented specifically by entry of a value of shunt admittance via activities RESQ or SQCH.

7. Lines considered zero-impedance branches in the positive-sequence are considered as zero impedance in the negative- and zero-sequence.

11.2.3. Fault Analysis Model Setup

The system model for fault analysis is set up in two main steps:

1. The power flow model is augmented with generator impedance and transformer phase-shift data as needed in fault analysis. This data is entered via activities READ or CHNG. The power flow case is resolved to adjust bus phase angles in accordance with the transformer phase shifts just entered.

2. The negative- and zero-sequence component parameters needed to establish the negative- and zero-sequence networks are entered via activities RESQ or SQCH.

The data entered in these two steps are appended to the basic power flow working case and become a part of it. After being entered, these data are saved and retrieved as a part of the power flow case by activities SAVE and CASE. The steps in augmenting the working file are summarized in Figure 11.1, “Steps in Setup of Model for Unbalanced Fault Analysis”. The equipment modeling considerations pertaining to the entry of data in these two steps are discussed in the next section.

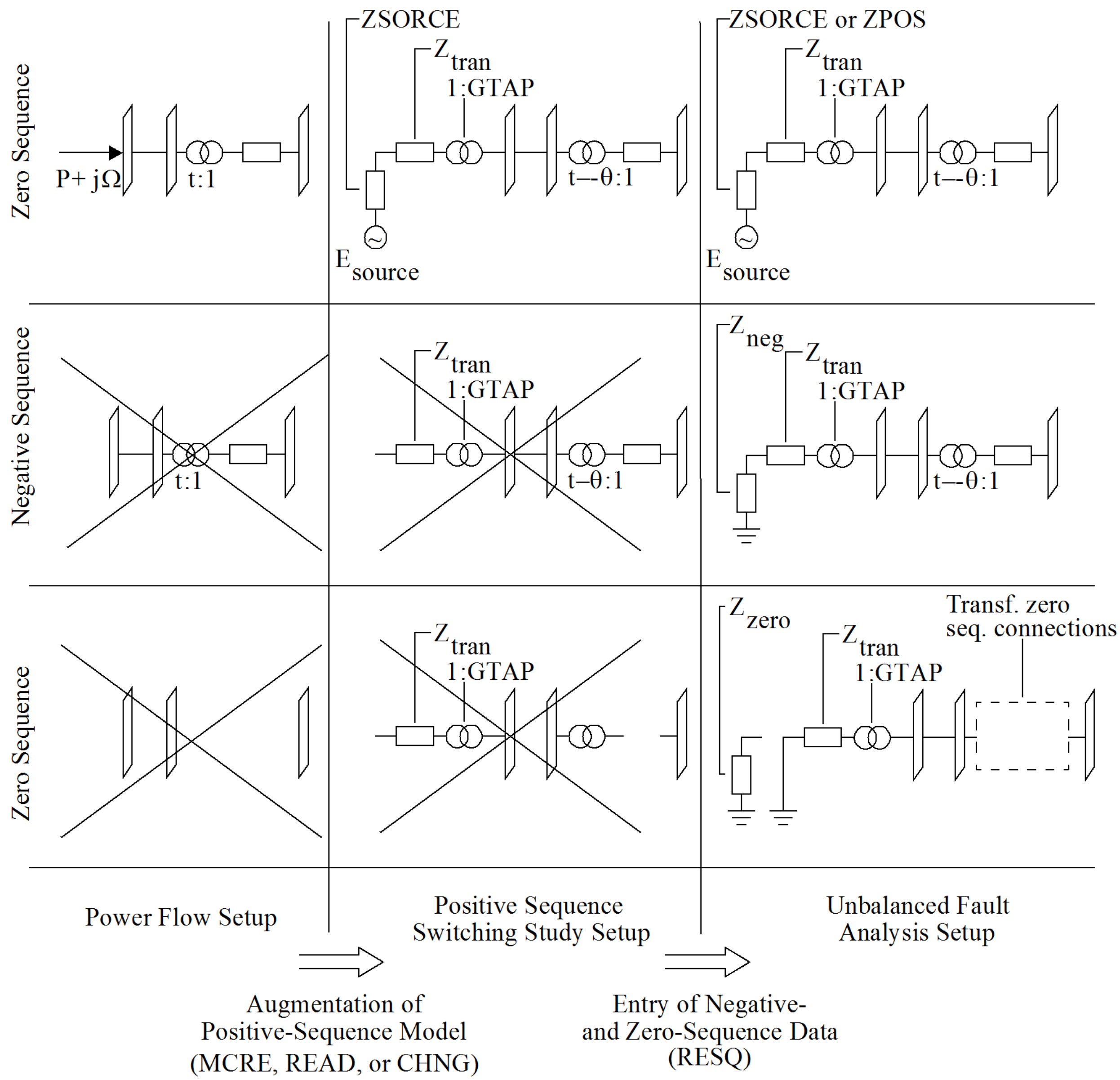


Figure 11.1. Steps in Setup of Model for Unbalanced Fault Analysis

11.2.4. Generators and Step-up Transformers

The unbalanced fault analysis is a switching study in the sense outlined in Section 5.6.2, "Positive-Sequence Representation of Generators" and Chapter 9, *Switching Studies*. It is a calculation of system conditions at the instant, t^+, given that the generator internal Norton source currents (or Thevenin source voltages) are unchanged from their condition at instant t^-, just prior to the event that perturbs the system.

Generators are modeled in conjunction with their step-up transformers as covered in Section 5.5, "Steady-State Boundary Conditions" and Section 5.6, "Dynamic Boundary Conditions". The generator positive-sequence internal conditions are determined from the working case conditions at instant, t^-, and frozen for solutions for conditions at instant, t^+, as outlined in Chapter 9, *Switching Studies*. This freezing of sources is handled by activity SEQD, not by CONG as in the case of balanced switching studies.

Each generator is modeled in the negative and zero-sequences as a simple impedance connected to ground at the generator neutral as shown in Figure 11.2, "Generator Modeling in Fault Analysis Database". The negative- and zero-sequence impedances of the generator are specified as the parameters ZNEG and ZZERO. The step-up transformer, if represented as a part of the generator, is assigned the same impedance, ZTRAN, in all three sequences. Figure 11.2, "Generator Modeling in Fault Analysis Database"a represents the generator model when the transformer is included with the generator, and Figure 11.2, "Generator Modeling in Fault Analysis Database"b represents it when the transformer is treated as a part of the transmission network. The generators may be characterized in the positive-sequence by either their dynamic impedances, ZSORCE, or a different positive-sequence impedance, ZPOS.

ZSORCE should always be set to the value, normally the subtransient impedance, Z'', required for representation of the generator in dynamic simulations. ZPOS may be set equal to ZSORCE or any other value, such as the transient impedance, Z', that may represent the generator in fault analysis studies. While the ZSORCE values assigned to the generators may be a mixture of subtransient and transient values, depending upon the modeling levels chosen for the individual generators, the ZPOS values should be consistently transient or subtransient values for all generators. The use of subtransient impedances as the values of ZPOS for all generators leads to fault calculations giving the conditions at an instant immediately after the unbalancing event. The use of transient values results in fault calculations giving conditions a short time, say 0.1 seconds, after the event when the subtransient components of the generator flux transients have died out and the generator can be regarded as a voltage source behind transient impedance.

Generators are modeled in the negative-sequence by the impedance, ZNEG, connected in series with the generator transformer reactance, ZTRAN, and thence to ground. The normal value for ZNEG is the *subtransient* impedance of the generator, regardless of the choice of values for ZSORCE and ZPOS. The generator zero-sequence model is the impedance, ZZERO, connected to ground. ZZERO should be assigned the value $(3R_g + jX_o)$, where

- R_g is the generator grounding resistance in per unit with respect to generator base voltage and generator base, MVA.
- X_o is the generator zero-sequence impedance, per unit, with respect to generator base, MVA.

When the generator step-up transformer is modeled as a part of the generator it is *always* treated as a two-winding unit:

- Delta-connected on the generator side.
- Wye-connected and solidly grounded on the transmission system side.
- Radial to the generator.

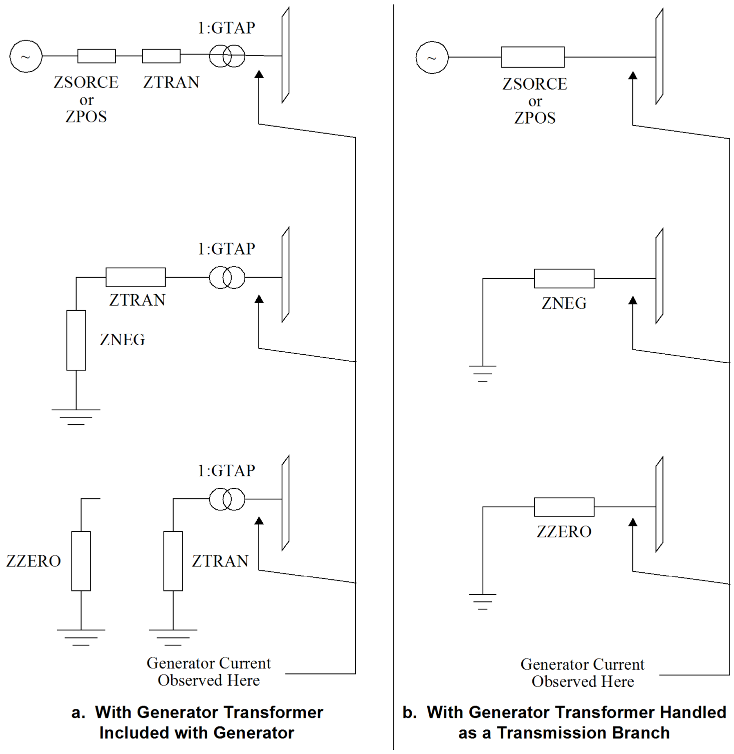


Figure 11.2. Generator Modeling in Fault Analysis Database

Plant arrangements where the step-up transformers cannot be modeled in this manner must have the transformers represented as a part of the transmission system. The plant connections produced in the three sequences by PSS®E are shown in Figure 11.2, "Generator Modeling in Fault Analysis Database". The generator zero-sequence impedance need not be specified when the step-up transformer is represented as part of the generator.

The unbalanced solutions of PSS®E calculate and display generator conditions only at the bus to which the generator is connected. Hence, inclusion of the step-up transformer precludes display of generator terminal conditions in the fault analysis results; all generator currents shown in fault analysis reports are as observed at the bus-side of the step-up transformer. Generator unbalanced *terminal* conditions can be observed only when the step-up transformer is represented as a transmission system branch, the generator zero-sequence impedance is specified, and the generator terminals are a bus in the system model.

11.2.5. Two-Winding Transformers

Equivalent Circuit

In most cases, the PSS®E user is responsible for devising a set of sequence equivalent circuits to represent each transformer, and building these up in the system model by establishing buses, branches, and shunt admittances as needed. The range of transformer connections in industrial use is huge and the proper modeling of some requires considerable ingenuity on the part of the analyst. The great majority of two-winding transformers, however, can be represented with acceptable accuracy by the positive-sequence equivalent circuit developed in Chapter 4, *Transformers in the Positive-Sequence*, used in conjunction with negative- and zero-sequence equivalent circuits of a closely related form, as shown in Figure 11.4, "Transformer Sequence Network Equivalents Produced Automatically by PSS®E".

The transformer equivalent circuits shown in Figure 11.4, "Transformer Sequence Network Equivalents Produced Automatically by PSS®E" are handled automatically in PSS®E. The positive-sequence network is constructed on the basis of the equivalent circuit shown in Figure 4.3, "Standard Per-Unit Form Transformer Equivalent Circuit". The negative-sequence equivalent circuit is taken to be identical to Figure 4-6 except for reversal of the phase-shift angle, θ .

The equivalent circuit used in constructing the zero-sequence network is one of the eight shown in Figure 11.4, "Transformer Sequence Network Equivalents Produced Automatically by PSS®E". The selection of the zero-sequence equivalent circuit is based on the transformer connection codes as shown in Figure 11.4, "Transformer Sequence Network Equivalents Produced Automatically by PSS®E".

In several parts of the world, the standard practice is to use wye-delta transformers from subtransmission voltages with the higher voltages being wye connected. Grounding on the lower voltage side is typically affected by means of a Z or zig-zag winding transformer with an earthing resistor. Typically, each grounding transformer is fitted such that when the wye-delta transformer is switched in or out connection codes 6 and 7 were added to provide this modeling. Figure 11.3, "Examples"shows two examples.

Connection code 5 was added for use in three-winding transformers. It was not added for any specific two-winding configurations.

The use of connection codes establishes only the form of the equivalent circuit to be used; it does not complete the representation of the transformer. The details of the transformer must be conveyed to PSS®E by the specification of proper zero-sequence impedance and positive-sequence phase-shift values. The zero-sequence impedance if they are different from the positive-sequence impedance needed to represent the transformer *must* be specified by entering a branch impedance value via activities RESQ or SQCH. The impedance used in the two-winding transformer zero-sequence circuits of Figure 11.4, "Transformer Sequence Network Equivalents Produced Automatically by PSS®E" is *always* entered as the through impedance (i.e., the impedance of a branch running from one bus to another), even though it may be routed from a bus to ground in the equivalent circuit. The user *does not* enter shunt branch data for the transformer ground paths when using the connection codes to establish the zero-sequence equivalent circuit.

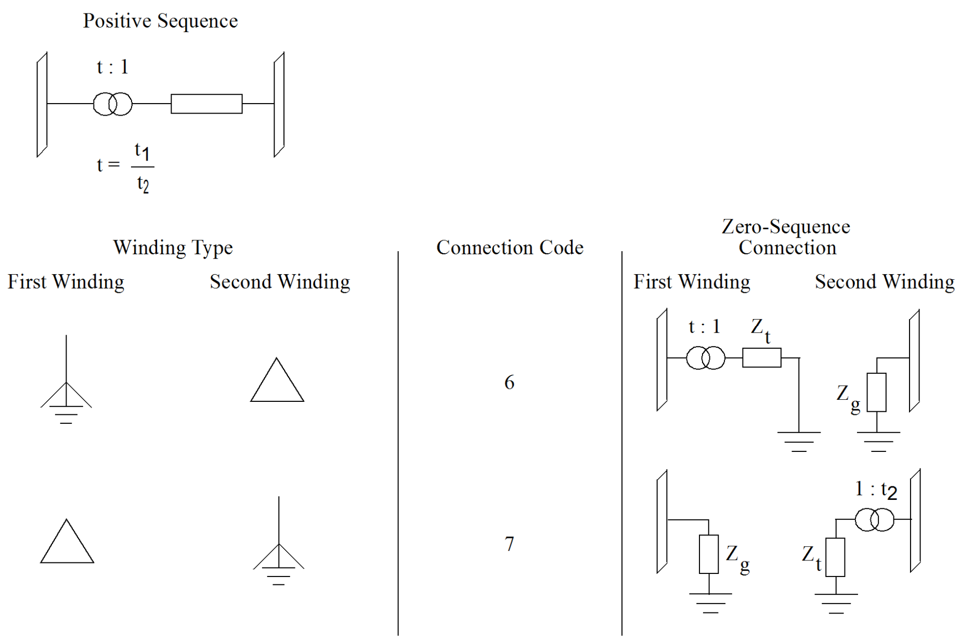


Figure 11.3. Examples

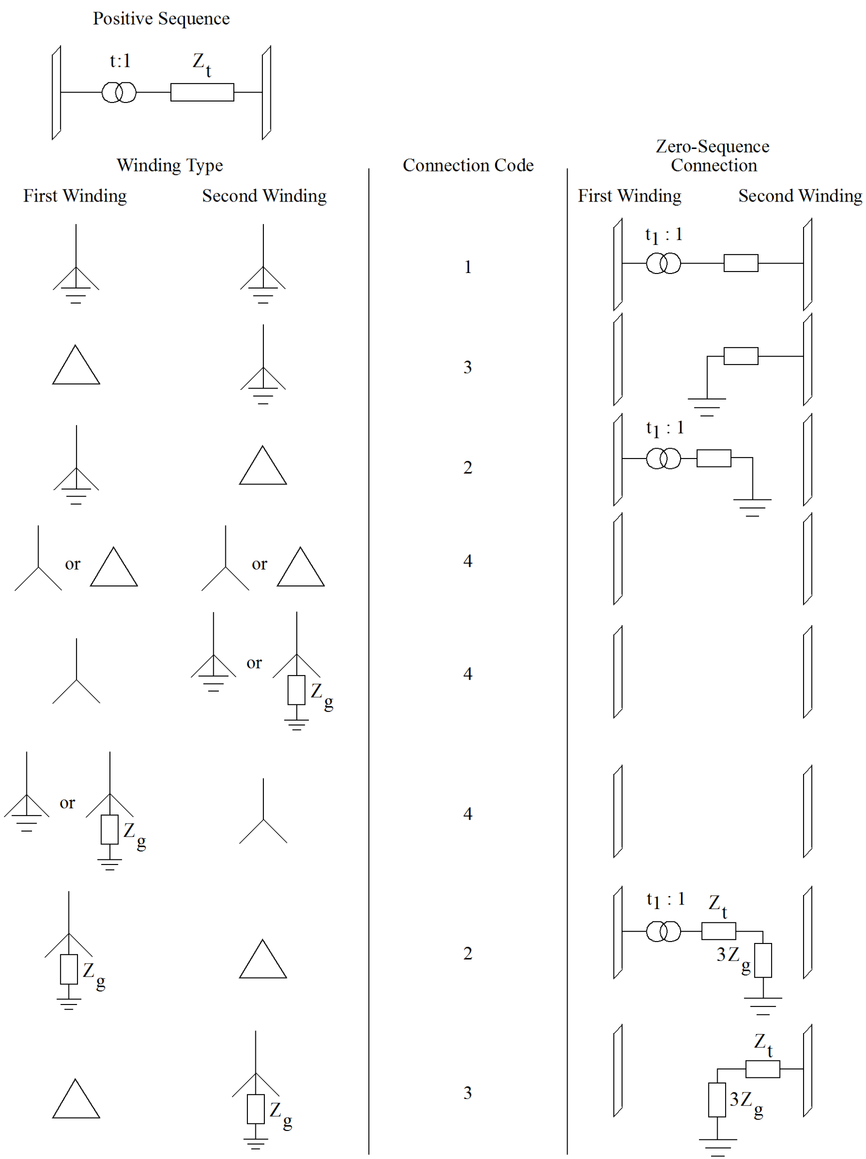


Figure 11.4. Transformer Sequence Network Equivalents Produced Automatically by PSS®E

The transformer impedance, Z_t, is not required to be equal to the transformer's positive-sequence impedance. Its value depends on the construction of the transformer tank and core, on the winding arrangements, and on the grounding of the two windings. The transformer grounding impedance should be entered. For winding connection codes 2, 3, and 5, the program will automatically multiply this value by 3.

The winding type codes *do not* distinguish between an ungrounded wye-winding and a delta-winding. This distinction is conveyed by the specification of transformer phase shift in the positive-sequence data. A delta-wye transformer, as shown in Figure 4-15, has an inherent 30° phase shift, which must be specified as a positive-sequence phase shift of either +30° or –30° in the power flow data if the behavior of the delta-wye transformer is to be represented completely.

If the 30° phase shift is not specified, it is implied that the transformer is either wye-wye or delta-delta connected.

When the transformer's positive-sequence leakage impedance is adjusted as a function of tap position in the positive-sequence (see the section called "Transformer Impedance Variation"), a dialog question in activity SEQD gives the user two options:

- Apply the impedance adjustment factor to the zero-sequence leakage impedance as well as to the positive-sequence impedance.
- Apply the impedance adjustment factor to the positive-sequence leakage impedance alone, and use the zero-sequence impedance value as entered via activity SEQD.
- In both cases the negative-sequence leakage impedance is adjusted by the impedance correction factor in the same way as the positive-sequence impedance. The single option selection applies to all transformers for which impedance adjustment is specified in the power flow data.

Effect of Neglecting Transformer Phase Shift

The significance of transformer phase shift, and the effect of ignoring it, is illustrated by Figure 11.5, "Representation of a Wye-Delta Transformer with and Without Its 30° Phase Shift" and Figure 11.6, "Effect of Including and Neglecting 30° Phase Shift in Transformer with One Grounded and One Ungrounded Winding". Consider the radially connected wye-delta transformer as shown in Figure 11.5, "Representation of a Wye-Delta Transformer with and Without Its 30° Phase Shift". It is represented as a two-winding transformer with a connection code of 2. The remaining details are specified via the phase-shift and impedance values. The correct representation is as shown in Figure 11.5, "Representation of a Wye-Delta Transformer with and Without Its 30° Phase Shift", with a 30° phase shift in the turns-ratio of the positive-sequence model. An incorrect, but often used representation, would be to ignore the phase shift, also shown in Figure 11.5, "Representation of a Wye-Delta Transformer with and Without Its 30° Phase Shift".

The fault analysis results, for a single phase-to-ground fault on the wye-connected winding, are shown in Figure 11.6, "Effect of Including and Neglecting 30° Phase Shift in Transformer with One Grounded and One Ungrounded Winding". Figure 11.6, "Effect of Including and Neglecting 30° Phase Shift in Transformer with One Grounded and One Ungrounded Winding"a shows the correct result obtained when transformer phase shift is represented properly. The sequence currents in the wye winding are given by

$I_0 = I_1 = I_2 = I_f / 3$

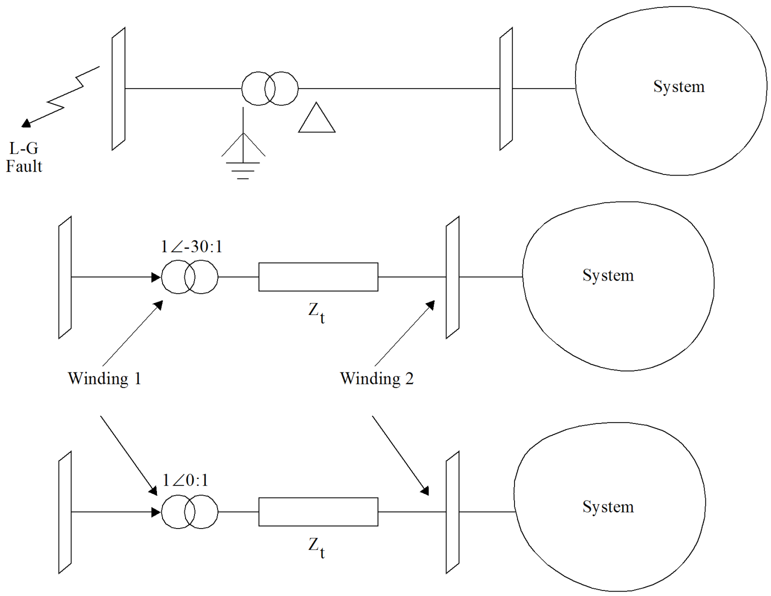


Figure 11.5. Representation of a Wye-Delta Transformer with and Without Its 30° Phase Shift

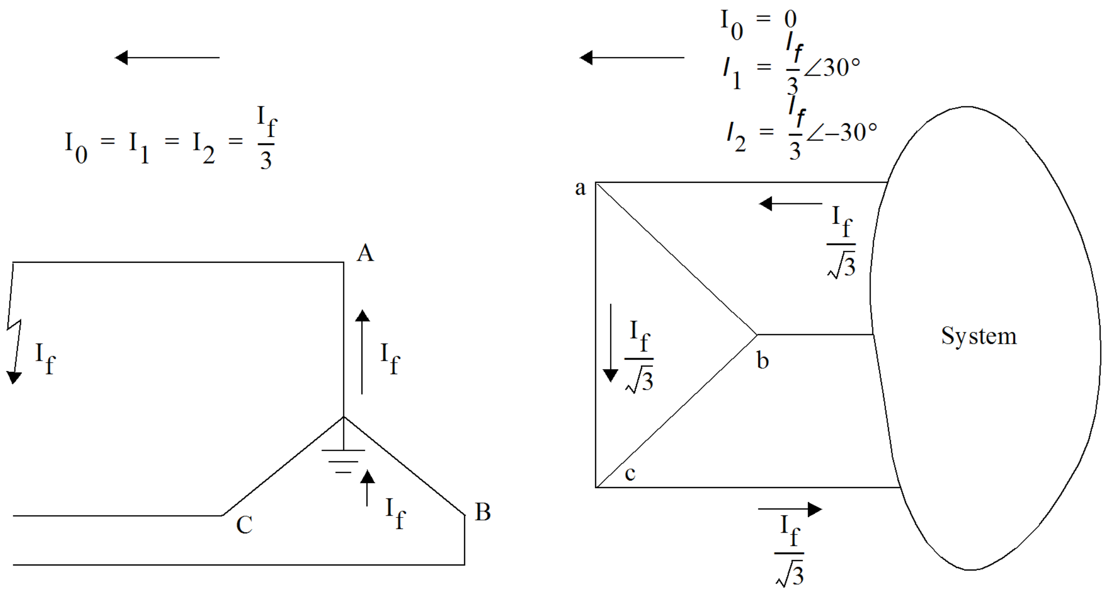
The sequence currents flowing in the leads to the delta-winding are given by

$I_0 = 0$

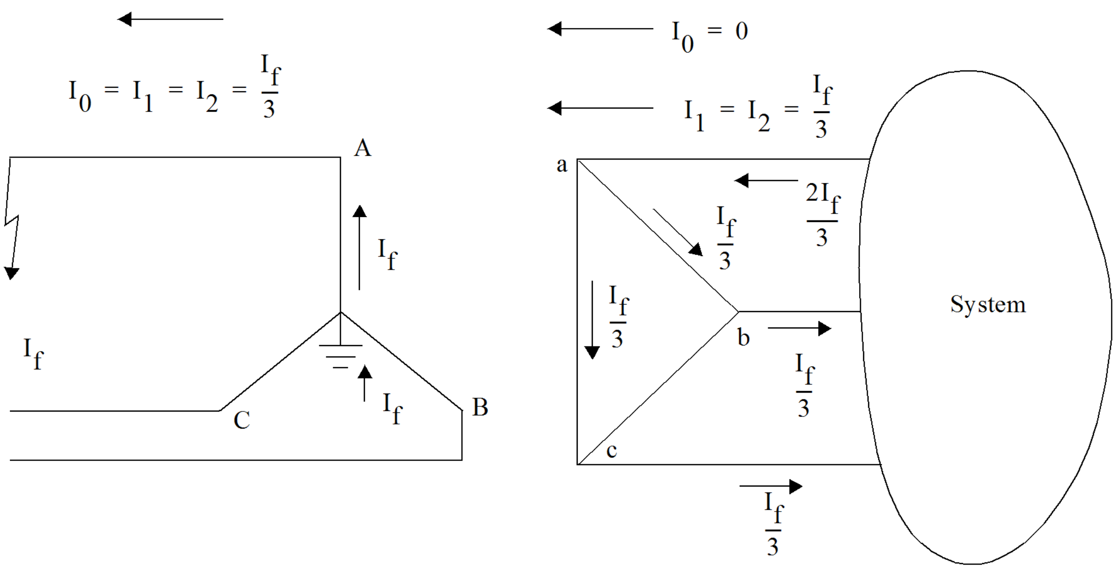
$I_1 = I_f \div 3$ at 30°

$I_2 = I_f \div 3$ at -30°

The phase currents corresponding to these delta-winding sequence currents are shown in Figure 11.6, "Effect of Including and Neglecting 30° Phase Shift in Transformer with One Grounded and One Ungrounded Winding"a. One leg of the delta connection carries a current of $I_f \div \sqrt{3}$, which flows in two of the leads on this side of the transformer. This data is correct with respect to magnitude and phase of the sequence currents, and to magnitude and phase of the transformer phase currents.



a. 30° Phase Shift Wye-Delta



b. No Phase Shift as if a Wye-Wye

Figure 11.6. Effect of Including and Neglecting 30° Phase Shift in Transformer with One Grounded and One Ungrounded Winding

Figure 11.6, “Effect of Including and Neglecting 30° Phase Shift in Transformer with One Grounded and One Ungrounded Winding”b shows the results obtained when the phase shift of the transformer is ignored. The sequence and phase currents on the fault side of the transformer are identical in amplitude to those calculated with phase shift present. (They are all shifted in phase by 30°, however.) The sequence and phase currents calculated for the delta-connected winding in the absence of transformer phase shift are significantly different from those shown in Figure 11.6, "Effect of Including and Neglecting 30° Phase Shift in Transformer with One Grounded and One Ungrounded Winding"a. While Figure 11.6, "Effect of Including and Neglecting 30° Phase Shift in Transformer with One Grounded and One Ungrounded Winding"a shows correct results with the positive- and negative-sequence leading and lagging the fault current by 30°, respectively, the results shown in Figure 11.6, "Effect of Including and Neglecting 30° Phase Shift in Transformer with One Grounded and One Ungrounded Winding"b have positive- and negative-sequence current in phase with the fault current. The lead currents corresponding to these sequence currents are as shown, with a current $2I_f \div 3$ in one phase and currents of $I_f \div 3$ in the other two. The corresponding currents in the delta-connected transformer windings are inconsistent with the currents in the wye-connected winding.

It is evident, then, that neglect of the inherent 30° phase shift of wye-delta transformers results in the following:

- Calculated sequence and phase currents that are correct in all branches on the fault side of the transformer.
- Calculated sequence currents that are correct in amplitude but erroneous in phase in all branches that are removed from the fault by a transformer.
- Erroneous values of phase current in all branches separated from the fault by a wye-delta transformer.

Representation of Transformer Phase Shift in Part of the System

Transformer phase-shift information may be specified in a subset of the complete network for which the net phase shift can be coordinated with the phase shift through the remainder of the network. It may, for example, be desired to specify phase shifts precisely for the transmission system of one company, but to ignore phase shifts in transformers in external systems. Figure 11.7, "Use of Detailed Transformer Phase-Shift Data to Allow Detailed Fault Analysis within a Subsystem of a Large Scale Power System Model" shows an example of this practice. Phase shift is specified exactly for all transformers within subsystem E, hence allowing the most detailed level of fault analysis for buses within its boundary, but phase shift at transformers outside the boundary is neglected. It is essential that the net phase shift between all boundary buses of subsystem E match the phase shift (usually zero) between the corresponding points in the external system where phase shifts are neglected. It would be incorrect, for example, to add a branch between buses 178 and 559. Correct 30° phase shifts would have to be added to *both* of transformers 558-559 and 563-564 to allow such an addition.

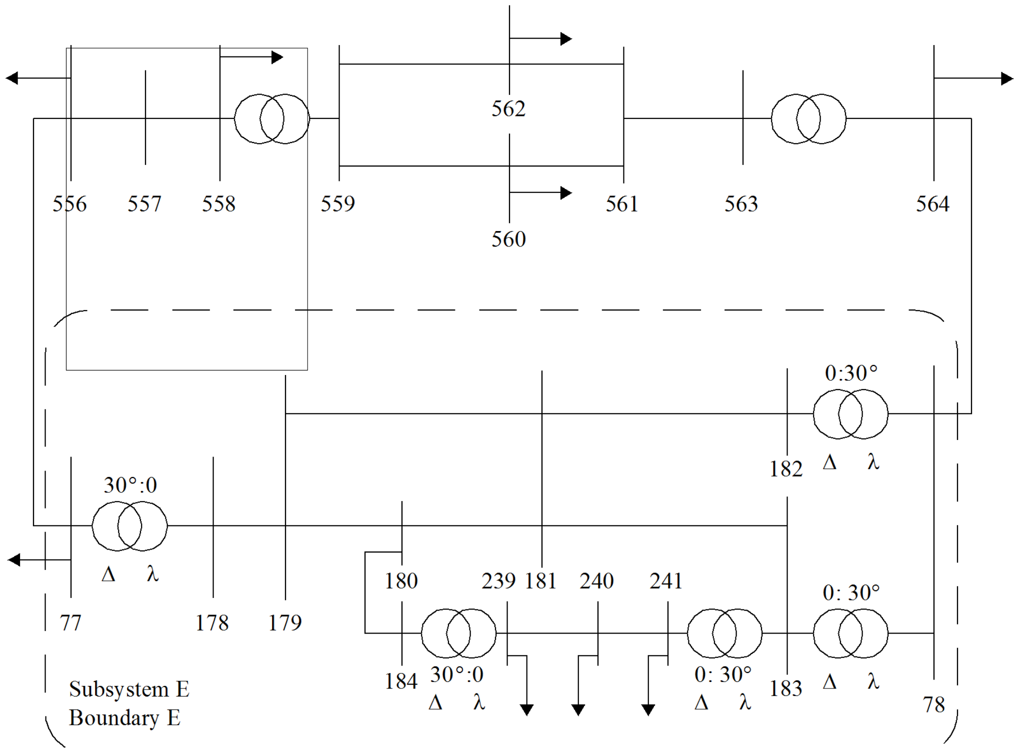
Neglect of transformer phase shifts places restrictions on both the application of simultaneous unbalances and the validity of the output of phase quantities.

Simultaneous Unbalances

Where the locations of simultaneous unbalances are separated by a transformer, the inherent phase shift of the transformer *must* be represented. In the system shown in Figure 11.7, "Use of Detailed Transformer Phase-Shift Data to Allow Detailed Fault Analysis within a Subsystem of a Large Scale Power System Model", it would be permissible to place simultaneous unbalances at buses 184 and 240, or 77 and 178, or 77 and 239, but not at buses 558 and 559, or 179 and 559.

Output of Phase Quantities

Phase quantities, as listed by activity SCMU and SCOP, are invalid at any point that can be reached from the fault point only by traversing a transformer where phase shift is neglected. In the situation shown in Figure 11.7, "Use of Detailed Transformer Phase-Shift Data to Allow Detailed Fault Analysis within a Subsystem of a Large Scale Power System Model", phase voltages and currents are printed correctly for all buses within boundary E, but the phase quantities printed for points outside this boundary are invalid.



Note 1:	SCMU and SCOP print phase quantities for all system locations regardless of their validity. The user must be aware of transformer phase-shift representations in order to determine the validity of outputs of phase quantities. WHEN IN DOUBT, REGARD PHASE OUTPUTS AS INVALID AND DO NOT USE THEM.
Note 2:	The phase shift of variable phase-shifting transformers should always be specified, regardless of the treatment of basic 30° transformer phase shifts.

For example, the phase shift of a delta-wye-connected phase-shifter device, used to regulate power flow within a cable network, as in the case where the advance of the tapped winding is 7°, should be entered in the power flow as:

37°	If the tapped side leads and nominal phase shifts of delta-wye transformers are represented.
7°	If the nominal phase shifts of delta-wye transformers are neglected.
–23°	If the tapped side lags and nominal phase shifts of delta-wye units are represented.

Figure 11.7. Use of Detailed Transformer Phase-Shift Data to Allow Detailed Fault Analysis within a Subsystem of a Large Scale Power System Model

Observation of Transformer Currents

Grounded wye-delta transformers pose a difficulty in unbalanced fault analysis because they behave as a shunt path to ground in the zero-sequence, while being series paths in the positive and negative sequences.

The distinction is between the transformer's symmetrical component equivalent circuits and the actual arrangements of its primary, secondary, and neutral leads.

Consider the currents flowing in the leads of a wye-delta transformer as shown in Figure 11.8, "Lead Current Flowing Into and Out of a Wye-Delta Transformer". The wye-connected winding allows zero-sequence current to flow into the transformer leads and thence to ground via the neutral grounding strap. While the wye-connected winding is certainly a path to ground, observations at the leads that feed this winding see the zero-sequence current just as if it were a series current flowing to the bus at the other side. This zero-sequence current in the transformer leads must be recognized in calculations of the phase values of the lead currents.

Consider the calculation of conditions at a bus where the following are connected:

- Transmission lines.
- A grounded wye-winding of a wye-delta transformer.
- A grounded wye-connected shunt reactor.
- A phase-to-ground fault somewhere on the bus side of all circuit breakers.

The bus arrangement is shown in Figure 11.9, "Transformer Zero-Sequence Currents Appearing in Alternative Network Representations of the Transformer"a. There are three components of zero-sequence current flowing from the bus to ground: fault current, reactor zero-sequence current, and transformer zero-sequence current. A conventional way of representing the bus is shown in Figure 11.9, "Transformer Zero-Sequence Currents Appearing in Alternative Network Representations of the Transformer"b. Here, the transformer is represented as a ground tie at the bus in the zero-sequence. The bus is assigned a shunt admittance equal to the sum of the reactor and transformer admittances. Use of this representation in system network solutions leads to correct results for bus positive-, negative-, and zero-sequence voltages. The subsequent calculation of transformer lead currents is erroneous, though, because the zero-sequence lead current appears to be zero when it should not be.

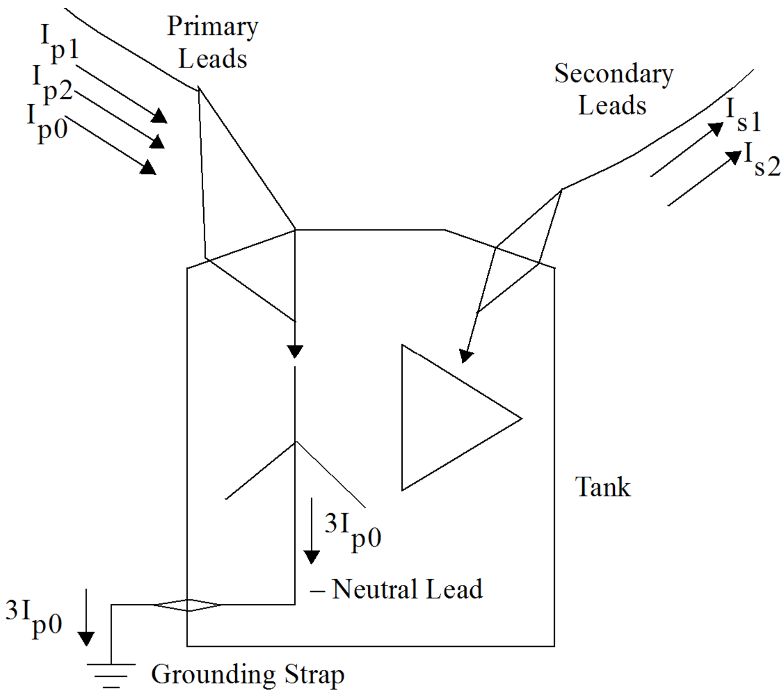
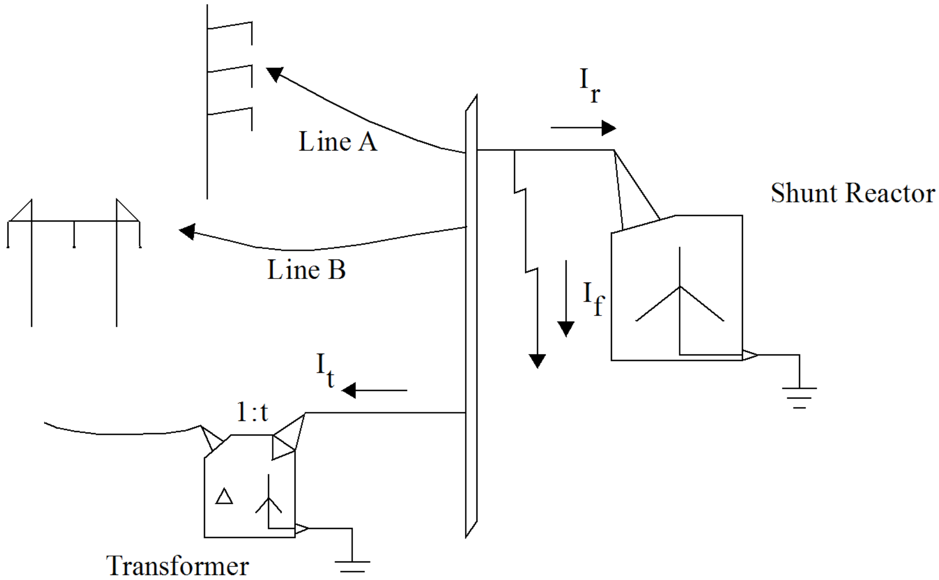
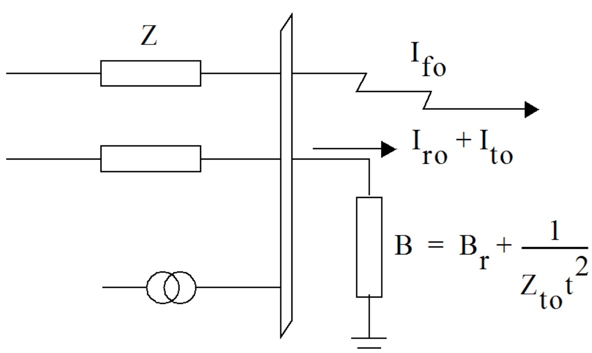


Figure 11.8. Lead Current Flowing Into and Out of a Wye-Delta Transformer

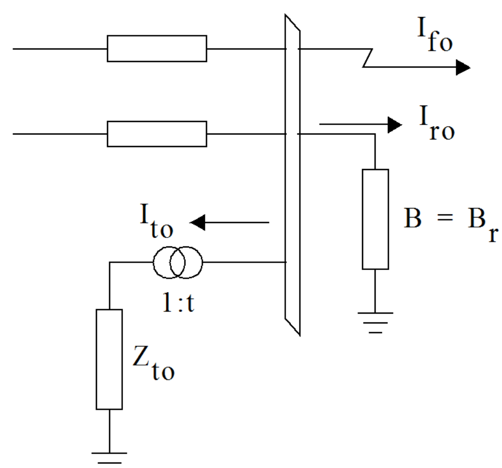
The alternative and recommended approach is to represent the transformer via the winding type code option of PSS®E. When the winding type code approach is used, the implied bus representation is as shown in Figure 11.9, “Transformer Zero-Sequence Currents Appearing in Alternative Network Representations of the Transformer”c. This results in the same system solution as obtained with the prior approach, but recognizes the zero-sequence current in the transformer leads. Calculations of transformer lead phase currents are correct, provided that the 30° phase shift of the transformer is handled properly as outlined in the section called “Effect of Neglecting Transformer Phase Shift”.



a. Bus with Grounding via Transformer, Shunt Reactor, and Fault



b. Bus Setup with Transformer Treated as Bus Ground Path



c. Bus Setup with Transformer Modeled via Winding Type Codes

Figure 11.9. Transformer Zero-Sequence Currents Appearing in Alternative Network Representations of the Transformer

While the winding type codes are normally used in the handling of the majority of transformers, use of manually determined shunt paths at buses may still be needed in special situations. When the winding type codes are not used, the following points must be noted:

- If wye windings of wye-delta transformers are to be represented as bus-connected shunt admittances to ground, the shunt admittance should be corrected for off-nominal turns ratio as shown by Figure 11.10, “Assignment of Zero-Sequence Shunt Branch for Typical Tapped Delta-Wye Transformers, Solidly Grounded”.

- When wye-delta transformers are represented by bus-connected shunt admittances, the phase currents calculated by PSS®E for the leads to the delta-connected winding are correct, but the phase currents displayed for the wye winding leads are erroneous.

- Because the bus modeling topology shown in Figure 11.9, “Transformer Zero-Sequence Currents Appearing in Alternative Network Representations of the Transformer”b is correct for bus arrangements other than that shown in Figure 11.9, “Transformer Zero-Sequence Currents Appearing in Alternative Network Representations of the Transformer”a, PSS®E must assume that all calculated branch phase currents are valid and leave it for the user to accept or reject the output values.

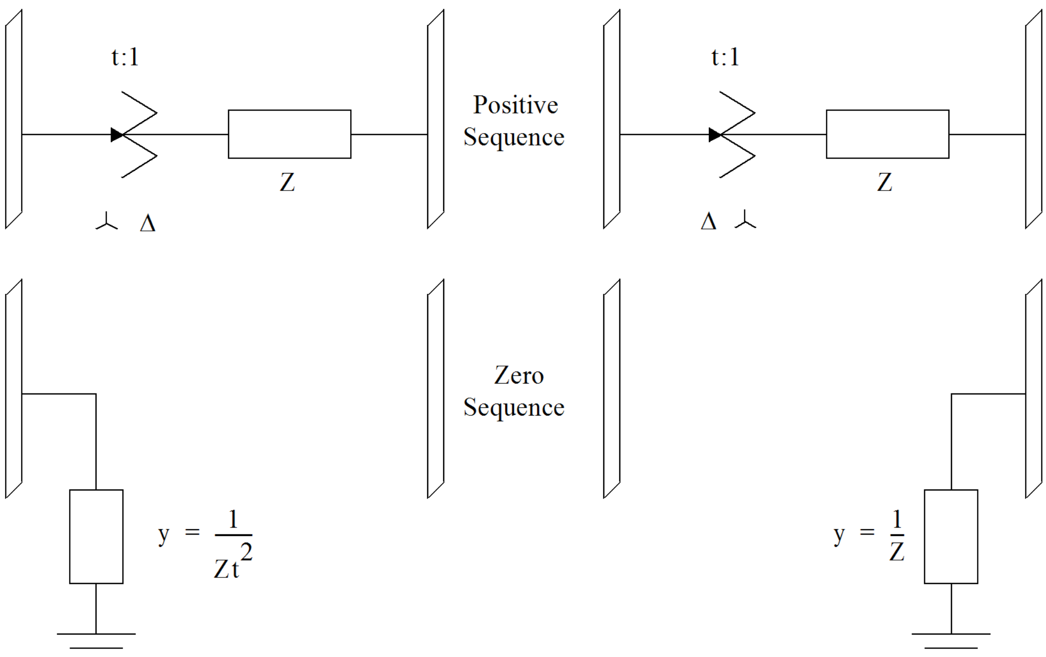


Figure 11.10. Assignment of Zero-Sequence Shunt Branch for Typical Tapped Delta-Wye Transformers, Solidly Grounded

11.2.6. Three-Winding Transformers

The variety of transformer connections for three-winding transformers far exceeds those for two-winding transformers. PSS®E currently models the few shown in Figure 11.11, “ PSS®E Three-Winding Connections”. The PSS®E user will have to provide the following information for each of these transformers:

- Proper connection code; default is 4, transformer open.

- Grounding impedance.
- Winding impedances, if different from the positive sequence.
- Positive-sequence phase angle.

For other three-winding conditions, it is the responsibility of the PSS®E user to construct the correct transformer equivalent circuit by the following entries:

- The correct form of the equivalent circuit for all three sequences, and the correct positive-sequence data, via activities READ and CHNG.
- The correct zero-sequence impedance and connection code data via activities RESQ and SQCH.

For those connections not modeled, three-winding transformer equivalent circuits will usually require a dummy bus between the primary and secondary buses. This bus must be included in the power flow (positive-sequence) case if it is to be used in the zero-sequence. The three-winding transformer model will have to be made up of three two-winding models with appropriate connections.

It is impractical to provide details of all of the huge variety of available transformer connections. Figure 11.11, " PSS®E Three-Winding Connections" shows the circuits needed in setting up power flow and fault analysis data for some common transformer arrangements. It is the responsibility of the user to ensure that each transformer is modeled by properly coordinated power flow and fault analysis data representing circuits of the type shown in Figure 11.11, " PSS®E Three-Winding Connections". A ground path is shown for connection code 1 at the center. This is used so that the user obtains the zero sequence exciting current contribution. Often this is neglected. Any or all of the branches used to represent a transformer may be set up as a two-winding transformer model. The use of a two-winding transformer may be desirable either because an off-nominal tap is needed, or because winding type codes will be needed to establish the proper modeling in the zero-sequence.

Figure 11.12, "Use of Transformer Branches with Fixed 1:1 Ratio to Allow Use of Winding Connection Codes in Modeling Three-Winding Transformers" shows alternatives to the three-winding equivalent circuits shown in Figure 11.11, " PSS®E Three-Winding Connections". These alternatives demonstrate how the use of two-winding models and branches can be used to correctly model a three-winding transformer.

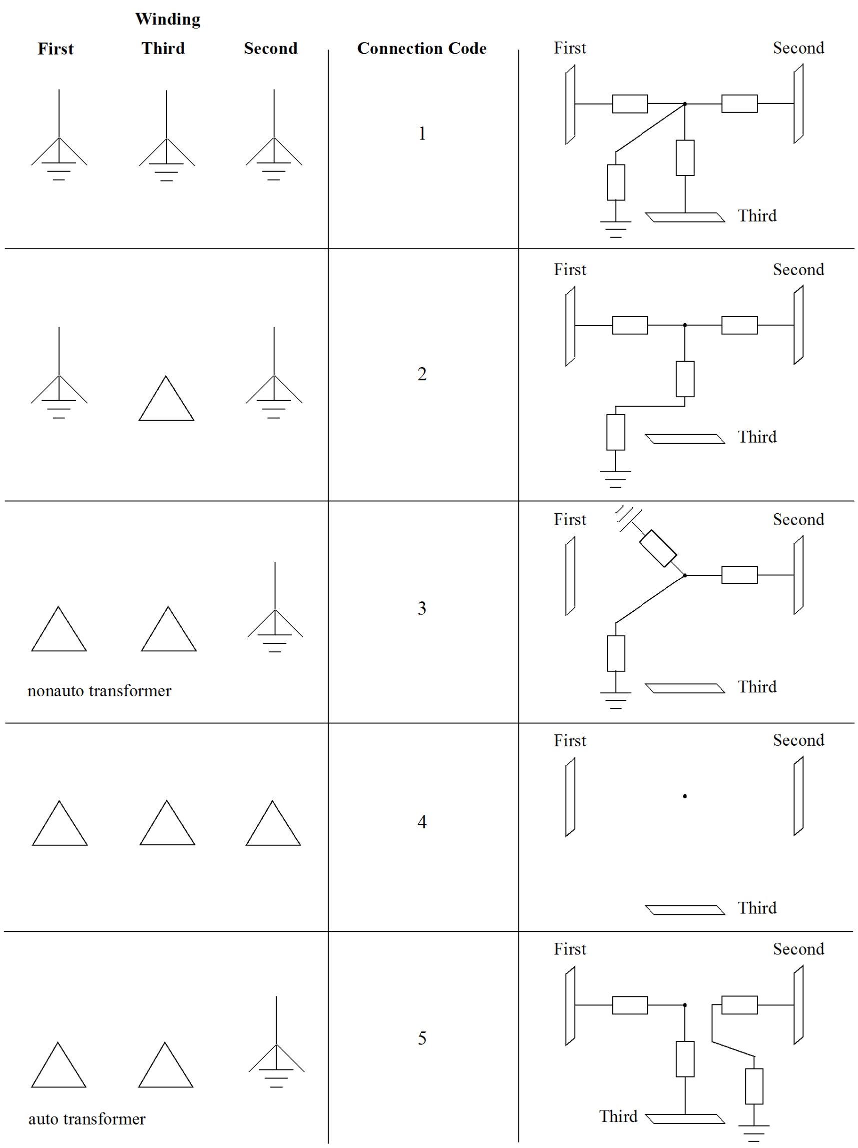


Figure 11.11. PSS®E Three-Winding Connections

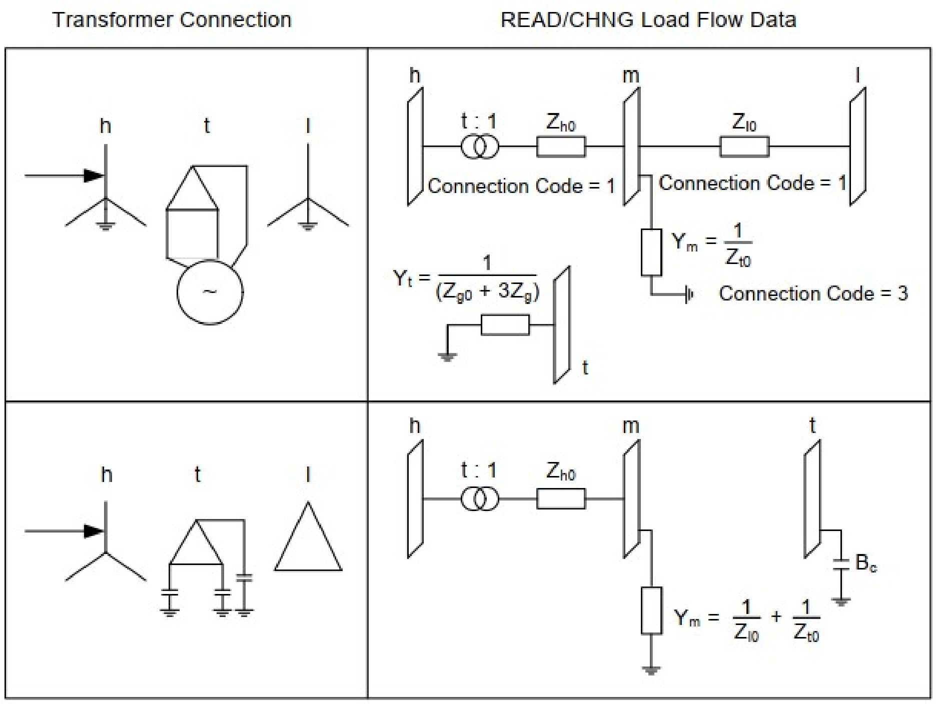


Figure 11.12. Use of Transformer Branches with Fixed 1:1 Ratio to Allow Use of Winding Connection Codes in Modeling Three-Winding Transformers

11.2.7. Transmission Line Mutual Impedance

Transmission lines sharing a right-of-way are usually coupled by a mutual impedance in the zero-sequence. Figure 11.13, "Section of Bulk Transmission Showing Geographic Distribution of Multiple Zero-Sequence Mutual Coupling Reactances" shows a situation in which a 400-kV line, a 230-kV line, and two 230-kV spurs all share a common right-of-way over parts of its length. Application of the transmission line constants program to the five line-segments in this subsystem produced values for all the elements of a zero-sequence coupling matrix as follows:

$$\begin{bmatrix} v_{3-4} \\ v_{2-7} \\ v_{8-5} \\ v_{2-10} \\ v_{11-5} \end{bmatrix} = j \begin{bmatrix} 0 & 0.035 & 0.054 & 0.008 & 0.01 \\ 0.035 & 0 & 0 & 0.028 & 0 \\ 0.054 & 0 & 0 & 0 & 0.035 \\ 0.008 & 0.028 & 0 & 0 & 0 \\ 0.01 & 0 & 0.035 & 0 & 0 \end{bmatrix} \begin{bmatrix} i_{3-4} \\ i_{2-7} \\ i_{8-5} \\ i_{2-10} \\ i_{11-5} \end{bmatrix}$$

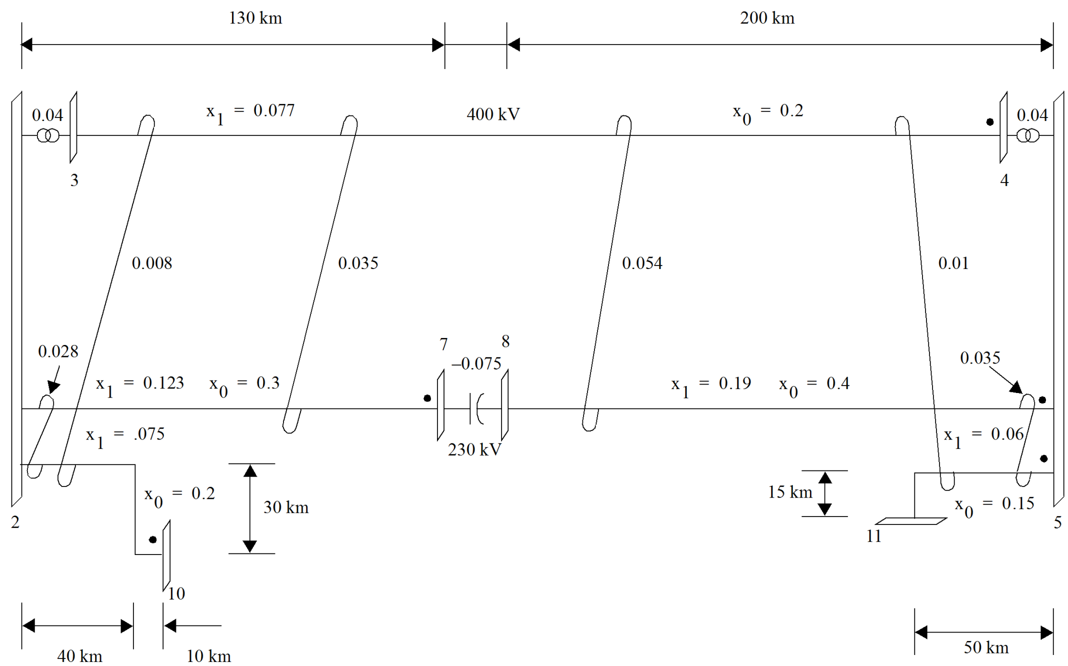


Figure 11.13. Section of Bulk Transmission Showing Geographic Distribution of Multiple Zero-Sequence Mutual Coupling Reactances

PSS®E can accommodate a number of zero-sequence mutual couplings as specified in the capacity table. The number of branches allowed in a mutually coupled group, as shown in Figure 11.13, "Section of Bulk Transmission Showing Geographic Distribution of Multiple Zero-Sequence Mutual Coupling Reactances" for example, is given in the capacity tables.

The PSS®E zero-sequence data specifications:

- The per-unit value of each zero-sequence mutual impedance between a pair of circuits.
- Geographic position of the mutually coupled parts of each transmission line.

Each mutual coupling is specified by a mutual coupling impedance, Z_m, and four line-distance factors, b_{ij1}, b_{ij2}, b_{kl1}, and b_{kl2}. The significance of these factors is as follows:

Zm

Total mutual impedance (a complex number) coupling circuit 1 to circuit 2.

bij1

Starting location of the mutual coupling along the first circuit from bus i to bus j relative to the bus i end of the branch.

bij2

Ending location of the mutual coupling along the first circuit from bus i to bus j relative to the bus i end of the branch.

bkl1

Starting location of the mutual coupling along the second circuit from bus k to bus l relative to the bus k end of the branch.

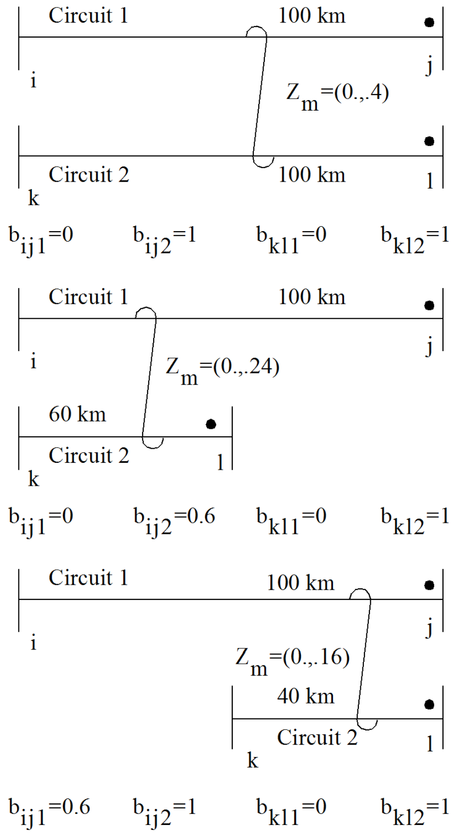
bkl2

Ending location of the mutual coupling along the second circuit from bus k to bus l relative to the bus k end of the branch.

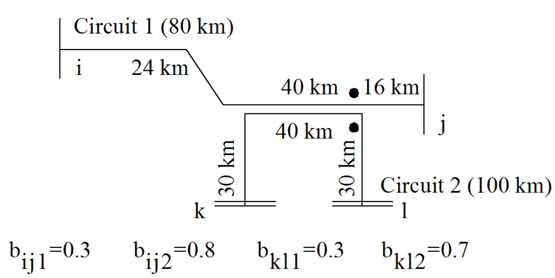
The specification of mutual coupling data is illustrated by Figure 11.14, "Mutual Couplings"a. The example considers coupling between a 100 km circuit, i-j, and other circuits that could share its right-of-way and be coupled to it. Inverse polarity is indicated by entering negative values for the mutual impedance between buses i,j and k,l. Geographic distribution of the mutual coupled lines must be specified if the full length of any line in a group is not involved in the coupling. Figure 11.14, "Mutual Couplings"b illustrates the specification of mutual coupling data for two lines sharing a right-of-way away from the substations.

- The branch directions used in specifying the *b* factors should be the same as used to specify Z_m (see description of activity RESQ for details on the entry of Z_m, b_{ij1}, b_{ij2}, b_{kl1}, b_{kl2} via activity RESQ and/or SQCH).

- The branch geographic, b, factors are used only in calculating in-line unbalances. They may be allowed to take on their default values (unity) when preparing data for activity RESQ, but the user must then remember to assign correct values via SQCH before applying unbalanced in-line faults on any such line.



a. Specification of Zero-Sequence Mutual Coupling Impedances



b. Mutual Coupling Specification for Lines Coupled Away From Substation

Figure 11.14. Mutual Couplings

11.2.8. Direct Current (dc) Transmission

The exact representation of dc transmission links under balanced and faulted conditions is beyond the scope of the symmetrical component method used throughout PSS®E. In view of this, activity SEQD allows dc links to be handled in one of two ways in unbalanced analysis:

1. All dc converters are treated as open circuits (i.e., fully blocked bridges) in all three sequences, regardless of their actual prefault loadings as given by the initial condition power flow.

2. Each dc converter is represented by an equivalent constant admittance load in the positive-sequence and by an open circuit in the negative- and zero-sequences. The equivalent positive-sequence shunt admittance is derived from the values of PAC and QAC given by the initial condition power flow at each converter ac bus.

Neither of these two representations should be regarded as exact. The first may be regarded as reasonable for the calculation of fault-current duty on circuit breakers because the controls of dc converters are usually designed to limit their fault currents to values equal to or less than normal load current.

The second of these two treatments is intended principally to allow the solution produced by SEQD, SCMU, and SCOP to match the initial condition power flow solution when no unbalance is applied. This treatment is useful for determining the apparent impedances seen along transmission lines under a balanced steady-state condition for which the working power flow case has been solved.

In addition to the above two standard treatments, the user may represent dc links by any combination of sequence shunt admittances that can be devised based on knowledge of a specific situation. To use this approach, the user should accept option (a) (all bridges blocked) in SEQD, having entered the appropriate shunt admittances at the converter ac buses via READ/RESQ and/or CHNG/SQCH.

11.2.9. System Model Setup Example

Figure 11.15, "Sample System for Fault Analysis" shows a sample system incorporating four transformers and two mutual couplings between three transmission lines. Figure 11.16, "Raw Data Files for Fault Analysis" through Figure 11.25, "Augmentation of Established Power Flow Case to Include Negative- and Zero-Sequence Networks (Sheet 1 of 2)" illustrate the setup of the working case for analysis of this system.

The generator step-up transformer at bus 100 is represented in the standard manner as a part of the generator. The two 138/33-kV transformers and the step-up transformer of the generator at bus 600 are represented as transmission network branches; all three of these are grounded wye-delta transformers. In addition, the load at bus 500 is fed through a transformer with an impedance of 0.1 per unit, grounded on the side connected to bus 500. This transformer does not appear in Figure 11.15, "Sample System for Fault Analysis", but its leakage impedance must be recognized as a zero-sequence path to ground at bus 500.

Substation 500 is geographically at the mid-point of the 33-kV line from bus 200 to bus 300 but, because the two 138-kV lines have different construction, the two mutual impedances are different. The circuit from 100 to 500 has a 5 Mvar shunt reactor connected on the line side of the circuit breaker at bus 500.

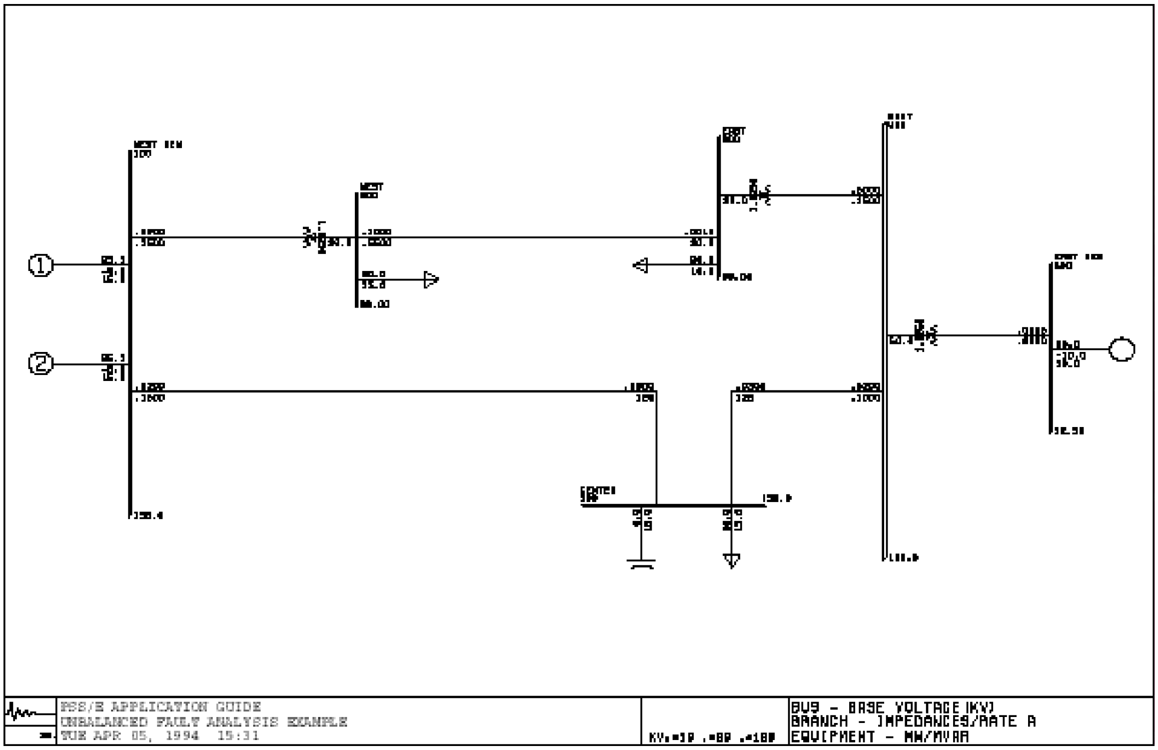


Figure 11.15. Sample System for Fault Analysis

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PSS®E APPLICATION GUIDE
UNBALANCED FAULT ANALYSIS EXAMPLE
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  200,'WEST    ',  33.0000,1,     0.000,     0.000,   1,   1,1.00120, -32.4195,   1
  300,'EAST    ',  33.0000,1,     0.000,     0.000,   1,   1,1.00607, -31.6659,   1
  400,'EAST    ', 138.0000,1,     0.000,     0.000,   1,   1,0.99805,   0.3077,   1
  500,'CENTER  ', 138.0000,1,     0.000,    15.000,   1,   1,0.99254,  -1.2778,   1
  600,'EAST GEN',  12.5000,2,     0.000,     0.000,   1,   1,1.00003,  36.2028,   1
0  / END OF BUS DATA, BEGIN LOAD DATA
  200,'1 ',1,   1,   1,    30.000,    15.000,     0.000,     0.000,     0.000,     0.000,   1
  300,'1 ',1,   1,   1,    20.000,    10.000,     0.000,     0.000,     0.000,     0.000,   1
  500,'1 ',1,   1,   1,    50.000,    15.000,     0.000,     0.000,     0.000,     0.000,   1
0 / END OF LOAD DATA, BEGIN GENERATOR DATA
  100,'1 ',    25.127,     8.854,    15.000,    -5.000,1.00000,    0,    30.000,   0.00000,   0.22000,   0.00000,   0.12000,1.02500,1,  100.0,    27.000,     9.000,   1,1.0000
  100,'2 ',    25.127,     8.854,    15.000,    -5.000,1.00000,    0,    30.000,   0.00000,   0.22000,   0.00000,   0.12000,1.02500,1,  100.0,    27.000,     9.000,   1,1.0000
  600,'1 ',    50.000,    15.718,    30.000,   -10.000,1.00000,    0,    60.000,   0.00000,   0.22000,   0.00000,   0.00000,0.00000,1,  100.0,    54.000,    18.000,   1,1.0000
0 / END OF GENERATOR DATA, BEGIN BRANCH DATA
  100,   500,'1 ',   0.02000,   0.10000,   0.03000,  125.00,  130.00,  135.00,  0.00000,  0.00000,  0.00000, -0.05000,1,   0.00,   1,1.0000
  200,   300,'1 ',   0.10000,   0.55000,   0.00100,   30.00,   35.00,   40.00,  0.00000,  0.00000,  0.00000,  0.00000,1,   0.00,   1,1.0000
  400,   500,'1 ',   0.02000,   0.10000,   0.03000,  125.00,  130.00,  135.00,  0.00000,  0.00000,  0.00000,  0.00000,1,   0.00,   1,1.0000
0 / END OF BRANCH DATA, BEGIN TRANSFORMER DATA
  200,  100,    0,'1 ',1,1,1,   0.00000,   0.00000,2,'        ',1,   1,1.0000
   0.00000,   0.15000,  100.00
1.02500,   0.000, -30.000,   30.00,   45.00,   60.00, 1,  -200, 1.02500, 0.95000, 1.02000, 1.00000, 13,  0, 0.00000, 0.00000
1.00000,   0.000
  300,  400,    0,'1 ',1,1,1,   0.00000,   0.00000,2,'        ',1,   1,1.0000
   0.00000,   0.15000,  100.00
1.02500,   0.000, -30.000,   30.00,   45.00,   60.00, 1,  -300, 1.05000, 0.95000, 1.02000, 1.00000, 17,  0, 0.00000, 0.00000
1.00000,   0.000
  400,  600,    0,'1 ',1,1,1,   0.00000,   0.00000,2,'        ',1,   1,1.0000
   0.00000,   0.20000,  100.00
1.02500,   0.000, -30.000,   60.00,   70.00,   80.00, 0,     0, 1.50000, 0.51000, 1.50000, 0.51000,159,  0, 0.00000, 0.00000
1.00000,   0.000
0 / END OF TRANSFORMER DATA, BEGIN AREA DATA
0 / END OF AREA DATA, BEGIN TWO-TERMINAL DC DATA
0 / END OF TWO-TERMINAL DC DATA, BEGIN SWITCHED SHUNT DATA
0 / END OF SWITCHED SHUNT DATA, BEGIN IMPEDANCE CORRECTION DATA
0 / END OF IMPEDANCE CORRECTION DATA, BEGIN MULTI-TERMINAL DC DATA
0 / END OF MULTI-TERMINAL DC DATA, BEGIN MULTI-SECTION LINE DATA
0 / END OF MULTI-SECTION LINE DATA, BEGIN ZONE DATA
0 / END OF ZONE DATA, BEGIN INTER-AREA TRANSFER DATA
0 / END OF INTER-AREA TRANSFER DATA, BEGIN OWNER DATA
0 / END OF OWNER DATA, BEGIN FACTS DEVICE DATA
0 / END OF FACTS DEVICE DATA
```

Bus data

Load data

Generator data

Branch data

Transformer data

Figure 11.16. Raw Data Files for Fault Analysis

```
0          / THU, JAN 13 2000  15:01
  100,'1 ',   0.00000,   0.40000  <--- Generator positive sequence, Z
  100,'2 ',   0.00000,   0.40000
  600,'1 ',   0.00000,   0.40000
 0
  100,'1 ',   0.00000,   0.22000  <--- Generator negative sequence, Z
  100,'2 ',   0.00000,   0.22000
  600,'1 ',   0.00000,   0.22000
 0
  100,'1 ',   0.00000,   0.40000  <--- Generator zero sequence, Z
  100,'2 ',   0.00000,   0.40000
  600,'1 ',   0.60000,   0.25000
 0
 0
  500,   0.00000, -10.00000  <--- Zero-sequence shunt path
 0
  100,   500,'1 ',   0.05000,   0.30000,   0.01500,  0.00000,  0.00000,  0.00000, -0.15000  <--- Branch zero sequence, Z
  200,   300,'1 ',   0.20000,   1.00000,   1.00000,  0.00050,  0.00000,  0.00000,  0.00000
  400,   500,'1 ',   0.05000,   0.30000,   0.01500,  0.00000,  0.00000,  0.00000,  0.00000
 0
  100,   500,'1 ',   200,   300,'1 ',   0.05000,   0.25000, 0.00000, 1.00000, 0.00000, 0.50000  <--- Zero-sequence mutual coupling
  400,   500,'1 ',   200,   300,'1 ',   0.00000,  -0.05000, 0.00000, 1.00000, 0.50000, 1.00000
 0
  100,   200,     0,'1 ',  2,   0.00000,   0.00000,   0.00000,   0.15000  <--- Transformer data
  300,   400,     0,'1 ',  2,   0.00000,   0.00000,   0.00000,   0.15000
  400,   600,     0,'1 ',  2,   0.00000,   0.00000,   0.00000,   0.20000
 0
 0
```

Sequence Raw Data Files for Fault Analysis

```
Executing activity READ,ALL  <------ Read power flow raw data

ENTER IC, SBASE

ENTER TWO LINE HEADING

ENTER BUS DATA

ENTER LOAD DATA

ENTER GENERATOR DATA

ENTER NON-TRANSFORMER BRANCH DATA

ENTER TRANSFORMER DATA

ENTER AREA INTERCHANGE DATA

ENTER TWO-TERMINAL DC LINE DATA

ENTER SWITCHED SHUNT DATA

ENTER TRANSFORMER IMPEDANCE CORRECTION DATA

ENTER MULTI-TERMINAL DC LINE DATA

ENTER MULTI-SECTION LINE DATA

ENTER ZONE NAME DATA

ENTER INTER-AREA TRANSFER DATA

ENTER OWNER NAME DATA

ENTER FACTS CONTROL DEVICE DATA

Executing activity SOLV  <------ Solve power flow base case

ITER DELTAV/TOL X------ AT BUS ------X  REAL(DELTAV)  IMAG(DELTAV)
   1  8792.348    300 [EAST     33.000]    0.2552E+00    0.8414E+00
   2  2788.824    500 [CENTER  138.00]   -0.2186E-01   -0.2780E+00
   3  3153.609    600 [EAST GEN12.500]    0.1653E+00   -0.2686E+00
   4  2037.017    300 [EAST     33.000]   -0.5896E-01   -0.1950E+00
   5   740.797    600 [EAST GEN12.500]    0.7330E-01    0.1071E-01
   6   838.917    600 [EAST GEN12.500]   -0.5437E-01    0.6389E-01
   7   374.322    600 [EAST GEN12.500]    0.3609E-01   -0.9918E-02
   8   290.965    200 [WEST     33.000]    0.2368E-01    0.1691E-01
   9   224.828    600 [EAST GEN12.500]    0.1729E-01   -0.1437E-01
  10   115.987    600 [EAST GEN12.500]   -0.1151E-01    0.1401E-02
  11    71.727    200 [WEST     33.000]   -0.7064E-02   -0.1246E-02
  12    56.225    600 [EAST GEN12.500]   -0.4952E-02    0.2663E-02
  13    30.975    600 [EAST GEN12.500]    0.3089E-02    0.2321E-03
  14    18.636    600 [EAST GEN12.500]   -0.1847E-02   -0.2504E-03
  15    12.620    600 [EAST GEN12.500]    0.1208E-02   -0.3657E-03
  16     7.436    600 [EAST GEN12.500]   -0.7141E-03   -0.2072E-03
  17     4.261    600 [EAST GEN12.500]    0.4103E-03    0.1149E-03
  18     2.621    600 [EAST GEN12.500]   -0.2585E-03    0.4305E-04
  19     1.607    600 [EAST GEN12.500]    0.1479E-03    0.6278E-04
  20     0.876    600 [EAST GEN12.500]   -0.8421E-04   -0.2412E-04

REACHED TOLERANCE IN  20 ITERATIONS

LARGEST MISMATCH:    -0.01 MW    0.04 MVAR     0.04 MVA AT BUS    500 [CENTER  138.00]
SYSTEM TOTAL ABSOLUTE MISMATCH:                0.13 MVA

SWING BUS SUMMARY:
  BUS X--- NAME ---X      PGEN      PMAX     PMIN      QGEN      QMAX    QMIN
 100 WEST GEN138.00       50.3      54.0     18.0      17.7      30.0   -10.0
```

Figure 11.17. Power Flow Setup to Establish Positive-Sequence Model for Fault Analysis (Sheet 1 of 2)

```
Executing activity SOLV

ITER DELTAV/TOL X------ AT BUS ------X  REAL(DELTAV)   IMAG(DELTAV)
   1  8799.215    300 [EAST     33.000]  -0.2549E+00   -0.8422E+00
   2  2870.314    500 [CENTER   138.00]  -0.1401E-02    0.2870E+00
   3  2860.821    600 [EAST GEN12.500]   -0.1347E+00    0.2524E+00
   4  2162.874    300 [EAST     33.000]   0.1338E+00    0.1699E+00
   5   626.269    500 [CENTER   138.00]  -0.2030E-01   -0.5925E-01
   6   668.921    600 [EAST GEN12.500]    0.4279E-01   -0.5142E-01
   7   452.023    300 [EAST     33.000]  -0.3645E-01   -0.2673E-01
   8   213.623    200 [WEST     33.000]  -0.1388E-02   -0.2132E-01
   9   186.529    600 [EAST GEN12.500]   -0.1580E-01    0.9907E-02
  10    71.064    600 [EAST GEN12.500]    0.7078E-02    0.6364E-03
  11    52.069    200 [WEST     33.000]   0.4523E-02    0.2580E-02
  12    51.367    600 [EAST GEN12.500]    0.4922E-02   -0.1471E-02
  13    27.330    200 [WEST     33.000]   0.2406E-02   -0.1297E-02
  14    19.470    200 [WEST     33.000]  -0.1786E-02    0.7750E-03
  15    12.813    600 [EAST GEN12.500]   -0.1281E-02    0.2117E-04
  16     9.429    200 [WEST     33.000]  -0.5308E-03    0.7793E-03
  17     5.576    200 [WEST     33.000]   0.3438E-03   -0.4390E-03
  18     3.315    200 [WEST     33.000]  -0.1104E-03    0.3126E-03
  19     1.980    200 [WEST     33.000]   0.1907E-04   -0.1970E-03
  20     0.947    600 [EAST GEN12.500]    0.6475E-04    0.6905E-04

REACHED TOLERANCE IN  20 ITERATIONS

LARGEST MISMATCH:     0.01 MW    -0.05 MVAR      0.05 MVA AT BUS    500
[CENTER   138.00]
SYSTEM TOTAL ABSOLUTE MISMATCH:                  0.16 MVA

SWING BUS SUMMARY:
  BUS X--- NAME ---X      PGEN      PMAX     PMIN      QGEN      QMAX     QMIN
  100 WEST GEN138.00      50.3      54.0     18.0      17.7      30.0    -10.0

Executing activity SAVE

CASE SAVED IN FILE C:\pag\ufsca ON THU, JAN 13 2000   15:16
```

Resolve base case to shift bus voltages in accordance with λ–Δ transformer phase shifts

Save prefault setup in full detail in file UFSCA

Figure 11.18. Power Flow Setup to Establish Positive-Sequence Model for Fault Analysis (Sheet 2 of 2)

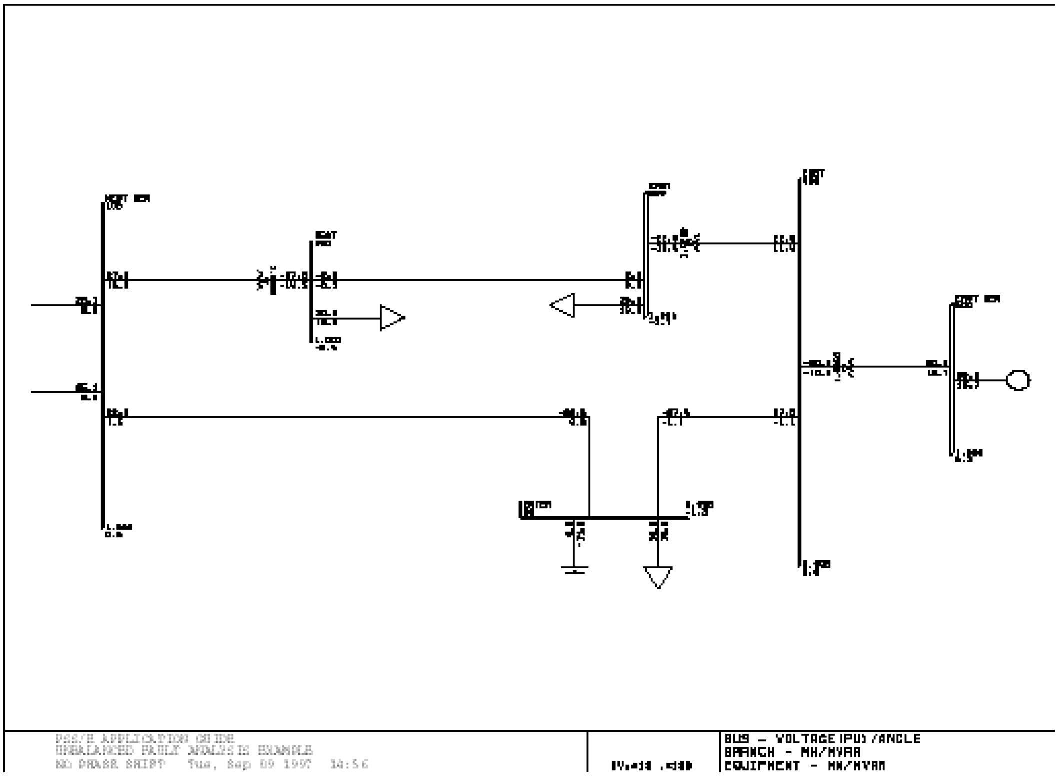

Figure 11.19. Pre-Event Power Flow Before Establishment of Transformer Phase Shift

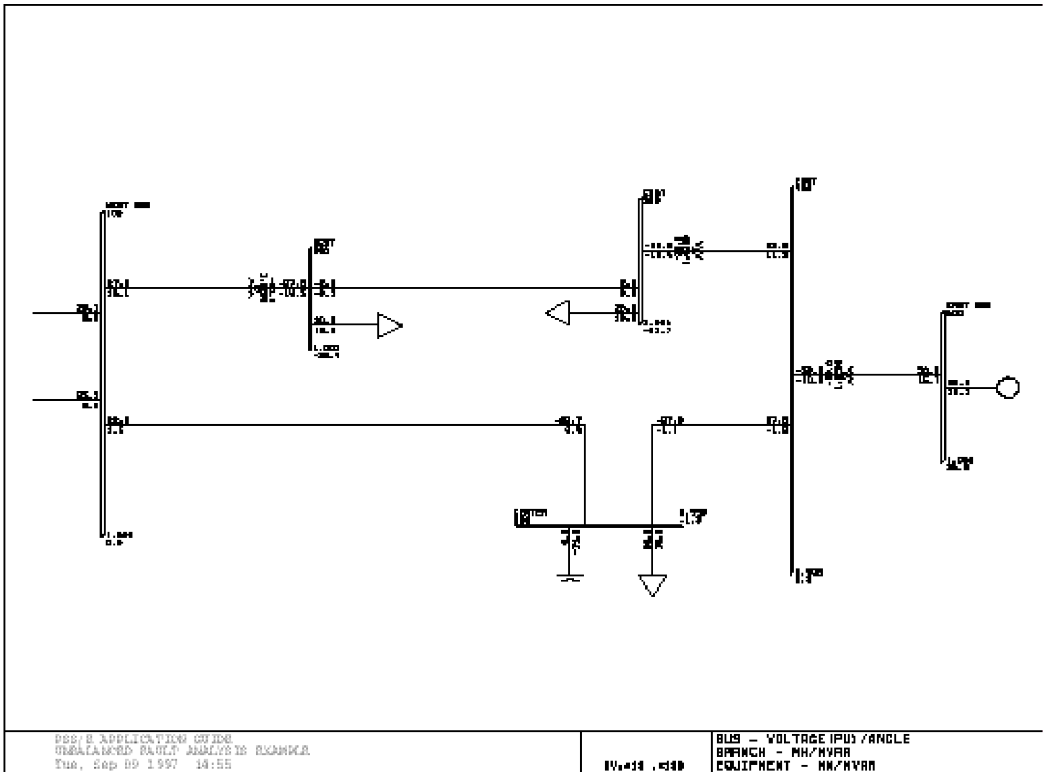

Figure 11.20. Pre-Event Power Flow with Transformer Phase Shift Included

```
     PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS®E      THU, JAN 13 2000  15:23
PSS®E APPLICATION GUIDE                                          SYSTEM SUMMARY
UNBALANCED FAULT ANALYSIS EXAMPLE

------------------BUSES------------------          GENERATION AREAS ZONES OWNERS AREA
TOTAL PQ<>0. PQ=0. PE/E  PE/Q SWING OTHER  LOADS PLANTS MACHS USED  USED  USED TRANS
    6     3     1     1     0     1     0      3     2     3     1     1     1     0
------------------AC BRANCHES------------------- 3WND MULTI-SECTION   DC LINES FACTS
 TOTAL     RXB     RX    RXT    RX=0.     IN     OUT XFRM  LINES SECTNS 2-TRM N-TRM DEVS
     6       3      0      3      0      6       0    0      0      0     0     0    0

TOTAL GENERATION PQLOAD   I LOAD   Y LOAD   SHUNTS  CHARGING  LOSSES    SWING
MW       100.3    100.0      0.0      0.0      0.0       0.0      0.3     50.3
MVAR      33.4     40.0      0.0      0.0     -9.9       6.1      9.3     17.7

TOTAL MISMATCH =    0.16 MVA X-----AT BUS-----X    SYSTEM   X------SWING-----X
 MAX. MISMATCH =    0.05 MVA   500 CENTER   138     BASE      100 WEST GEN 138
  HIGH VOLTAGE = 1.00607 PU    300 EAST    33.0    100.0
  LOW  VOLTAGE = 0.99254 PU    500 CENTER   138 ADJTHR ACCTAP TAPLIM   THRSHZ
                                                0.0050 1.0000 0.0500  0.000100
X-------SOLV AND MSLV-------X   X---NEWTON---X   X------TYSL------X BLOW  PQ
 ACCP  ACCQ  ACCM   TOL  ITER   ACCN  TOL ITER   ACCTY    TOL  ITER  UP  BRAK
1.600 1.600 1.000 0.00010 100   1.00 0.100  20   1.000 0.000010  20  5.0 0.70

     PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS®E      THU, JAN 13 2000  15:23
PSS®E APPLICATION GUIDE                                              WORST
UNBALANCED FAULT ANALYSIS EXAMPLE                                 MISMATCHES
 BUS#   NAME  BSKV        MW        MVAR        MVA
  500 CENTER   138     -0.01        0.05       0.05
  400 EAST     138      0.03       -0.03       0.04
  200 WEST    33.0     -0.03        0.01       0.03
  300 EAST    33.0      0.00        0.02       0.02
  600 EAST GEN12.5      0.00       -0.02       0.02

     PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS®E      THU, JAN 13 2000  15:23
PSS®E APPLICATION GUIDE                                            BUS DATA
UNBALANCED FAULT ANALYSIS EXAMPLE
 BUS#   NAME   BSKV  CODE LOADS  VOLT   ANGLE       S H U N T   AREA ZONE OWNER
  100 WEST GEN138.00   3     0 1.0000    0.0     0.0       0.0     1    1     1
  200 WEST    33.000   1     1 1.0012  -32.4     0.0       0.0     1    1     1
  300 EAST    33.000   1     1 1.0061  -31.7     0.0       0.0     1    1     1
  400 EAST    138.00   1     0 0.9981    0.3     0.0       0.0     1    1     1
  500 CENTER  138.00   1     1 0.9925   -1.3     0.0      15.0     1    1     1
  600 EAST GEN12.500   2     0 1.0000   36.2     0.0       0.0     1    1     1

     PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS®E      THU, JAN 13 2000  15:23
PSS®E APPLICATION GUIDE                                           LOAD DATA
UNBALANCED FAULT ANALYSIS EXAMPLE
 BUS#   NAME  BSKV ID CD ST   PSI     MVA-LOAD      CUR-LOAD       Y - LOAD   AREA ZONE OWNER
  200 WEST    33.0 1   1 1  1.000   30.0    15.0   0.0     0.0    0.0     0.0    1    1     1
  300 EAST    33.0 1   1 1  1.000   20.0    10.0   0.0     0.0    0.0     0.0    1    1     1
  500 CENTER   138 1   1 1  1.000   50.0    15.0   0.0     0.0    0.0     0.0    1    1     1
```

Figure 11.21. Pre-Event Power Flow Data Including Solved Bus Voltages (Sheet 1 of 4)

```
     PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS®E      THU, JAN 13 2000  15:23
PSS®E APPLICATION GUIDE                                          GENERATING
UNBALANCED FAULT ANALYSIS EXAMPLE                                PLANT DATA
 BUS#   NAME  BSKV COD MCNS PGEN   QGEN   QMAX   QMIN VSCHED  VACT. PCT Q REMOTE
  100 WEST GEN 138  3   2   50.3   17.7   30.0  -10.0 1.0000 1.0000 100.0
  600 EAST GEN12.5  2   1   50.0   15.7   30.0  -10.0 1.0000 1.0000 100.0

     PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS®E      THU, JAN 13 2000  15:23
PSS®E APPLICATION GUIDE                                           GENERATOR
UNBALANCED FAULT ANALYSIS EXAMPLE                                 UNIT DATA
 BUS#   NAME  BSKV CD ID ST  PGEN   QGEN   QMAX   QMIN   PMAX   PMIN OWN FRACT OWN FRACT  MBASE  Z S O R C E    X T R A N    GENTAP
  100 WEST GEN 138  3 1  1   25.1    8.9   15.0   -5.0   27.0    9.0   1 1.000             30.0 0.0000 0.2200 0.0000 0.1200 1.02500
  100 WEST GEN 138  3 2  1   25.1    8.9   15.0   -5.0   27.0    9.0   1 1.000             30.0 0.0000 0.2200 0.0000 0.1200 1.02500
  600 EAST GEN12.5  2 1  1   50.0   15.7   30.0  -10.0   54.0   18.0   1 1.000             60.0 0.0000 0.2200

     PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS®E      THU, JAN 13 2000  15:23
PSS®E APPLICATION GUIDE                                           SWITCHED
UNBALANCED FAULT ANALYSIS EXAMPLE                                SHUNT DATA
 BUS# MOD  VHI    VLO     SHUNT  X-------X X-------X X-------X X-------X REMOTE

                                   * NONE *

     PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS®E      THU, JAN 13 2000  15:23
PSS®E APPLICATION GUIDE                                         BRANCH DATA
UNBALANCED FAULT ANALYSIS EXAMPLE
X------FROM------X  X-------TO-------X                         Z S
 BUS# NAME    BSKV   BUS# NAME    BSKV CKT   LINE R   LINE X   CHRGING I T  RATEA  RATEB  RATEC LENGTH OWN1 FRAC1 OWN2 FRAC2 OWN3 FRAC3 OWN4 FRAC4
  100 WEST GEN 138*   500 CENTER   138  1   0.02000  0.10000  0.03000   1  125.0  130.0  135.0    0.0    1 1.000
  200 WEST    33.0*   300 EAST    33.0  1   0.10000  0.55000  0.00100   1   30.0   35.0   40.0    0.0    1 1.000
  400 EAST     138*   500 CENTER   138  1   0.02000  0.10000  0.03000   1  125.0  130.0  135.0    0.0    1 1.000

     PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS®E      THU, JAN 13 2000  15:23
PSS®E APPLICATION GUIDE                                     LINE SHUNT DATA
UNBALANCED FAULT ANALYSIS EXAMPLE
X------FROM------X X-------TO-------X
 BUS# NAME    BSKV  BUS# NAME    BSKV CKT   LINE G,B (FROM)    LINE G,B (TO) ST
  100 WEST GEN 138   500 CENTER   138  1    0.0000   0.0000    0.0000  -0.0500 1

     PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS®E      THU, JAN 13 2000  15:23
PSS®E APPLICATION GUIDE                                       2 WINDING XFRMER
UNBALANCED FAULT ANALYSIS EXAMPLE                              IMPEDANCE DATA
X------FROM------X X-------TO-------X      XFRMER  C C
 BUS# NAME    BSKV  BUS# NAME    BSKV CKT   NAME   Z M   R 1-2     X 1-2  W1BASE   MAG1    MAG2  RATA RATB RATC TBL   NOMINAL R,X    OWN FRACT OWN FRACT
  100 WEST GEN 138   200 WEST    33.0  1           1 1  0.00000  0.15000  100.0  0.0000  0.0000   30   45   60  0                    1 1.000
  300 EAST    33.0   400 EAST     138  1           1 1  0.00000  0.15000  100.0  0.0000  0.0000   30   45   60  0                    1 1.000
  400 EAST     138   600 EAST GEN12.5  1           1 1  0.00000  0.20000  100.0  0.0000  0.0000   60   70   80  0                    1 1.000

     PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS®E      THU, JAN 13 2000  15:23
PSS®E APPLICATION GUIDE                                      2 WINDING XFRMER
UNBALANCED FAULT ANALYSIS EXAMPLE                           TAP & CONTROL DATA
X------FROM------X X-------TO-------X     S M W C                                                       X--CONTROLLED BUS-X
 BUS# NAME    BSKV  BUS# NAME    BSKV CKT T T 1 W WINDV1 NOMV1 ANGLE WINDV2 NOMV2 CN  RMAX   RMIN   VMAX   VMIN  NTPS  BUS# NAME    BSKV   CR     CX
  100 WEST GEN 138   200 WEST    33.0  1  1 T T 1 1.0250 0.000 -30.0 1.0000 0.000  1 1.0250 0.9500 1.0200 1.0000   13  -200 WEST    33.0
  300 EAST    33.0   400 EAST     138  1  1 F F 1 1.0250 0.000 -30.0 1.0000 0.000  1 1.0500 0.9500 1.0200 1.0000   17  -300 EAST    33.0
  400 EAST     138   600 EAST GEN12.5  1  1 F F 1 1.0250 0.000 -30.0 1.0000 0.000  0 1.5000 0.5100 1.5000 0.5100  159
```

Figure 11.22. Pre-Event Power Flow Data Including Solved Bus Voltages (Sheet 2 of 4)

```
     PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS®E      THU, JAN 13 2000  15:23
PSS®E APPLICATION GUIDE                                        3 WINDING XFRMER
UNBALANCED FAULT ANALYSIS EXAMPLE                               IMPEDANCE DATA
 XFRMER  X--WINDING 1 BUS-X X--WINDING 2 BUS-X X--WINDING 3 BUS-X     S C
  NAME     BUS# NAME     BSKV  BUS# NAME     BSKV  BUS# NAME     BSKV CKT T Z   R 1-2     X 1-2     R 2-3     X 2-3     R 3-1     X 3-1   OWNR FRACT OWNR FR

                                   * NONE *

     PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS®E      THU, JAN 13 2000  15:23
PSS®E APPLICATION GUIDE                                        3 WINDING XFRMER
UNBALANCED FAULT ANALYSIS EXAMPLE                                WINDING DATA
 XFRMER  X---WINDING BUS--X  S C C C                                                                  STAR POINT BUS
  NAME     BUS# NAME     BSKV  T W Z M  R WNDNG  X WNDNG  WBASE WIND V NOM V  ANGLE RATA RATB RATC    MAG1     MAG2  VOLTAGE  ANGLE TBL    NOMINAL R

                                   * NONE *

     PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS®E      THU, JAN 13 2000  15:23
PSS®E APPLICATION GUIDE                                        3 WINDING XFRMER
UNBALANCED FAULT ANALYSIS EXAMPLE                                CONTROL DATA
 XFRMER  X--WINDING 1 BUS-X C C                                    X--CONTROLLED BUS-X                    X------- NOMINAL IMPEDANCES -------X
  NAME     BUS# NAME     BSKV W Z CN  RMAX   RMIN   VMAX   VMIN  NTPS   BUS# NAME    BSKV    CR      CX   TBL  R 1-2    X 1-2    R 3-1    X 3-1

                                   * NONE *

     PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS®E      THU, JAN 13 2000  15:23
PSS®E APPLICATION GUIDE                                          TRANSFORMER Z
UNBALANCED FAULT ANALYSIS EXAMPLE                               CORRECTION DATA

                                   * NONE *

     PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS®E      THU, JAN 13 2000  15:23
PSS®E APPLICATION GUIDE                                           MULTI-SECTION
UNBALANCED FAULT ANALYSIS EXAMPLE                                   LINE DATA
X----- MULTI-SECTION LINE GROUPING ----X X------------ LINE SECTIONS ------------X
X----- FROM -----X X------ TO ------X ID X----- FROM -----X X------ TO ------X CKT

                                   * NONE *

     PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS®E      THU, JAN 13 2000  15:23
PSS®E APPLICATION GUIDE                                            DC LINE DATA
UNBALANCED FAULT ANALYSIS EXAMPLE

                                   * NONE *

     PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS®E      THU, JAN 13 2000  15:23
PSS®E APPLICATION GUIDE                                              AREA DATA
UNBALANCED FAULT ANALYSIS EXAMPLE
X-- AREA --X X-------------- AREA SWING --------------X X--- DESIRED ---X
              BUS#   NAME  BSKV    PGEN    PMAX    PMIN INTERCHANGE TOLER BUSES     LOADS  DC BUSES
  1              0                                           0.0     10.0     6         3         0
                                        SUMMATION:           0.0
```

Figure 11.23. Pre-Event Power Flow Data Including Solved Bus Voltages (Sheet 3 of 4)

```
     PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS®E      THU, JAN 13 2000  15:23
PSS®E APPLICATION GUIDE                                           INTER-AREA
UNBALANCED FAULT ANALYSIS EXAMPLE                               TRANSFER DATA
X--FROM AREA-X X---TO AREA--X ID  PTRANS  PTOTAL  DESINT

                                   * NONE *

     PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS®E      THU, JAN 13 2000  15:23
PSS®E APPLICATION GUIDE                                             ZONE DATA
UNBALANCED FAULT ANALYSIS EXAMPLE
X-- ZONE --X BUSES      LOADS  DC BUSES
  1             6          3         0

     PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS®E      THU, JAN 13 2000  15:23
PSS®E APPLICATION GUIDE                                            OWNER DATA
UNBALANCED FAULT ANALYSIS EXAMPLE
X-- OWNER -X BUSES      LOADS  MACHINES  BRANCHES  DC BUSES  FACTS DEVS
  1             6          3         3         6         0         0
     PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS®E      THU, JAN 13 2000  15:23
PSS®E APPLICATION GUIDE                                         FACTS CONTROL
UNBALANCED FAULT ANALYSIS EXAMPLE                                DEVICE DATA
FD# X- SENDING BUS --X X- TERMINAL BUS -X MODE  PDES   QDES  V SET SHNTMX BRDGMX  VTMAX  VTMIN VSRMAX ISRMAX  LINE X OWNER

                                   * NONE *
```

Figure 11.24. Pre-Event Power Flow Data Including Solved Bus Voltages (Sheet 4 of 4)

```
Executing activity RESQ

ENTER IC

ENTER POSITIVE SEQUENCE MACHINE IMPEDANCES

ENTER NEGATIVE SEQUENCE MACHINE IMPEDANCES

ENTER ZERO SEQUENCE MACHINE IMPEDANCES

ENTER NEGATIVE SEQUENCE SHUNTS

ENTER ZERO SEQUENCE SHUNTS

ENTER ZERO SEQUENCE NON-TRANSFORMER BRANCH DATA

ENTER MUTUAL DATA

ENTER ZERO SEQUENCE TRANSFORMER DATA

ENTER SWITCHED SHUNT DATA

Executing activity SAVE

CASE SAVED IN FILE C:\pag\ufsqa ON THU, JAN 13 2000  15:26
```

Read sequence data

Save the augmented power flow case over original power flow saved case

```
1      PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS®E      THU, JAN 13 2000  15:26
 PSS®E APPLICATION GUIDE                                               BUS DATA
 UNBALANCED FAULT ANALYSIS EXAMPLE
  BUS# COD ZER SEQ SHUNT NEG SEQ SHUNT POS SEQ SHUNT    MVA-LOAD     CURRENT-LOAD      Y-LOAD
   100  3  0.000   0.000 0.000 0.000 0.000 0.000
   200  1  0.000   0.000 0.000 0.000 0.000 0.000  0.300  0.150  0.000  0.000  0.000  0.000
   300  1  0.000   0.000 0.000 0.000 0.000 0.000  0.200  0.100  0.000  0.000  0.000  0.000
   400  1  0.000   0.000 0.000 0.000 0.000 0.000
   500  1  0.000 -10.000 0.000 0.000 0.000 0.150  0.500  0.150  0.000  0.000  0.000  0.000
   600  2  0.000   0.000 0.000 0.000 0.000 0.000
```

Admittance due to load transformer not appearing in power flow case

15-Mvar ungrounded capacitor

Only exceptions would be shown here

```
1      PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS®E      THU, JAN 13 2000  15:26
 PSS®E APPLICATION GUIDE                                             GENERATOR
 UNBALANCED FAULT ANALYSIS EXAMPLE                                   UNIT DATA
  BUS#  ID   ZGEN (ZERO)    ZGEN (POS.)    ZGEN (NEG.) MBASE   X T R A N   GENTAP
   100  1  0.0000 0.4000  0.0000 0.4000  0.0000 0.2200    30 0.0000 0.1200 1.0250
   100  2  0.0000 0.4000  0.0000 0.4000  0.0000 0.2200    30 0.0000 0.1200 1.0250
   600  1  0.6000 0.2500  0.0000 0.4000  0.0000 0.2200    60 0.0000 0.0000 0.0000

1      PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS®E      THU, JAN 13 2000  15:26
 PSS®E APPLICATION GUIDE                                              SWITCHED
 UNBALANCED FAULT ANALYSIS EXAMPLE                                   SHUNT DATA
  BUS#        SHUNT X-------X X-------X X-------X X-------X X-------X X-------X X-------X X-------X

                                   * NONE *
```

Figure 11.25. Augmentation of Established Power Flow Case to Include Negative- and Zero-Sequence Networks (Sheet 1 of 2)

```
1      PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS®E      THU, JAN 13 2000  15:26
 PSS®E APPLICATION GUIDE                                            BRANCH DATA
 UNBALANCED FAULT ANALYSIS EXAMPLE
                                     Z     S X-- POS AND NEG SEQ --X X--- ZERO SEQUENCE ---X X--POS & NEG SEQ LINE SHUNT-X X--ZERO SEQUENCE LINE SHUNT-X
 X--- FROM BUS ---X X---- TO BUS ----X CKT T    R       X       B       R       X       B       G,B (FROM)       G,B (TO)       G,B (FROM)       G,B (TO)
   100 WEST GEN 138    500 CENTER    138  1  1  0.0200  0.1000  0.0300  0.0500  0.3000  0.0150  0.0000 0.0000  0.0000-0.0500  0.0000 0.0000  0.0000-0.1500
           MUTUAL      200 WEST     33.0     300 EAST     33.0    CKT 1   0.0500  0.2500

   200 WEST     33.0   300 EAST     33.0  1  1  0.1000  0.5500  0.0010  0.2000  1.0000  1.0000  0.0000 0.0000  0.0000 0.0000  0.0005 0.0000  0.0000 0.0000
           MUTUAL      100 WEST GEN 138      500 CENTER   138     CKT 1   0.0500  0.2500
           MUTUAL      400 EAST      138     500 CENTER   138     CKT 1   0.0000 -0.0500

   400 EAST      138   500 CENTER    138  1  1  0.0200  0.1000  0.0300  0.0500  0.3000  0.0150
           MUTUAL      200 WEST     33.0     300 EAST     33.0    CKT 1   0.0000 -0.0500

1      PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS®E      THU, JAN 13 2000  15:26
 PSS®E APPLICATION GUIDE                                          TWO-WINDING
 UNBALANCED FAULT ANALYSIS EXAMPLE                              TRANSFORMER DATA
                                           S W C X-- POS & NEG --X X--------- ZERO SEQUENCE ---------X X- 1ST WIND -X 2ND WND     MAGNETIZING Y
 X--- FROM BUS ---X X---- TO BUS ----X CKT T 1 C       R        X         R        X      RGROUND  XGROUND  RATIO    ANGLE  RATIO       G        B
   100 WEST GEN 138    200 WEST     33.0  1  1 T 2  0.00000  0.15000  0.00000  0.15000  0.00000  0.00000 1.02500  -30.0 1.00000  0.00000  0.00000
   300 EAST     33.0   400 EAST      138  1  1 F 2  0.00000  0.15000  0.00000  0.15000  0.00000  0.00000 1.02500  -30.0 1.00000  0.00000  0.00000
   400 EAST      138   600 EAST GEN12.5   1  1 F 2  0.00000  0.20000  0.00000  0.20000  0.00000  0.00000 1.02500  -30.0 1.00000  0.00000  0.00000

1      PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS®E      THU, JAN 13 2000  15:26
 PSS®E APPLICATION GUIDE                                         THREE-WINDING
 UNBALANCED FAULT ANALYSIS EXAMPLE                              TRANSFORMER DATA
  XFRMER     S                        S C X-- POS & NEG --X X--------- ZERO SEQUENCE ---------X               MAGNETIZING Y
   NAME   CKT T   CC X---WINDING BUS--X T C      R         X         R         X     RGROUND  XGROUND  RATIO    ANGLE     G         B

                                       * NONE *

1      PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS®E      THU, JAN 13 2000  15:26
 PSS®E APPLICATION GUIDE                                            MUTUAL DATA
 UNBALANCED FAULT ANALYSIS EXAMPLE
  FROM     TO CKT    FROM     TO CKT  MUTUAL IMPEDANCE    BIJ1    BIJ2   BKL1   BKL2
   100    500  1      200    300  1    0.0500    0.2500  0.0000 1.0000 0.0000 0.5000
   200    300  1      400    500  1    0.0000   -0.0500  0.5000 1.0000 0.0000 1.0000
```

Mutual impedance between 100-500 and 200-300

Figure 11.26. Augmentation of Established Power Flow Case to Include Negative- and Zero-Sequence Networks (Sheet 2 of 2)

Figure 11.16, "Raw Data Files for Fault Analysis" shows the power flow and fault analysis raw data files for this system. While the transformer winding type codes in the sequence data file reflect the grounding of the delta-wye transformers, their 30° phase shifts are not entered in the power flow raw data file.

Figure 11.17, "Power Flow Setup to Establish Positive-Sequence Model for Fault Analysis (Sheet 1 of 2)" shows the dialog establishing the pre-event power flow base case and positive-sequence model. The first solution is made in conventional power flow style and produces the solution shown in Figure 11.19, "Pre-Event Power Flow Before Establishment of Transformer Phase Shift". If used in fault analysis, this solved power flow case would result in correct sequence current amplitudes in single-fault situations, but would yield erroneous phase currents in the situations pointed out in the section called "Effect of Neglecting Transformer Phase Shift". The second solution shown in Figure 11.18, "Power Flow Setup to Establish Positive-Sequence Model for Fault Analysis (Sheet 2 of 2)" is made after use of data editors to enter the 30° phase shifts of transformers 100-200, 300-400, and 400-600. This solution has to adjust the phase angle of buses 200, 300, and 600, but change nothing else. Figure 11.20, "Pre-Event Power Flow with Transformer Phase Shift Included" shows the result. It is the same as that in Figure 11.19, "Pre-Event Power Flow Before Establishment of Transformer Phase Shift" with respect to both flows and voltage amplitudes, but has the phase of the 33-kV subsystem (buses 200 and 300) and of bus 600 swung backward by 30°. The phase shift between buses 300 and 400 is 2° in Figure 11.19, "Pre-Event Power Flow Before Establishment of Transformer Phase Shift" and 32° in Figure 11.20, "Pre-Event Power Flow with Transformer Phase Shift Included". The use of activity SAVE at the end of Figure 11.17, "Power Flow Setup to Establish Positive-Sequence Model for Fault Analysis (Sheet 1 of 2)" saves the positive-sequence setup as a conventional power flow case. Figure 11.20, "Pre-Event Power Flow with Transformer Phase Shift Included" shows a power flow data listing corresponding to this pre-event network solution.

Figure 11.25, "Augmentation of Established Power Flow Case to Include Negative- and Zero-Sequence Networks (Sheet 1 of 2)" shows the dialog augmenting the positive-sequence saved case with negative- and zero-sequence network models. Use of activity SAVE writes the original power flow case back on the disk and extends the disk file to save the negative- and zero-sequence data.

Activity SQLIZ lists data on all three sequence models in a format intended primarily for convenience in fault analysis work. *All* data is stated in per-unit terms; transmission system data on system base, and data for each generator on its individual base, MVA.

The negative-sequence shunt values listed in the bus data by SQLI are nonzero only when a value has been entered via RESQ or SQCH. An entry of zero for a negative-sequence shunt *does not* imply absence of a shunt path in the negative-sequence network; it means that the negative-sequence shunt admittance at the bus will be set to the same value as the net positive-sequence admittance (i.e., load treated as admittance plus positive-sequence shunt admittance).

11.2.10. Pre-Event Conditions

Pre-Event Source Voltages

All system solutions made by activity SCMU give conditions at instant t^+, subject to the condition that the internal voltage sources of all rotating machines are unchanged from their values at instant, t^-, just prior to the application of the disturbance. The internal sources are determined by activity SEQD on the basis of the generator terminal voltages and outputs present in the power flow arrays of the working case. The results of fault analysis calculations, therefore, depend on the system power flow voltage estimate in the working case as well as on system impedances.

Conditioning of the Pre-Event Voltages

Use for the pre-event voltages in the working file:

- Determine the pre-event generator source voltages.
- Determine the admittance used to represent each load in the positive sequence.

If the fault analysis is to be based on full power flow detail, the working case should be solved before SEQD is run. The generator internal source voltages will then reflect the level of excitation and flux linkage needed to support load current, and the results calculated by SCMU for instant t^+ will show both fault current and load current that continues to flow in unfaulted parts of the system.

When fault analysis is based on a lesser level of detail, or where the pre-event power flow situation is unknown, the voltages in the working case should normally be set uniformly to (1 + j0) before SEQD is run. The conditioning of pre-event conditions is handled by Activity FLAT,CL.

The default action of FLAT,CL is to set all bus voltages to (1 + j0), all generator outputs, (PGEN + jQGEN), to zero and all transformer phase-shift angles to zero. This action causes SEQD to see all generators as if they are at rated voltage with zero current just prior to the disturbance, and to set all internal source voltages to (1 + j0). Execution of Activity FLAT,CL also sets all loads to zero. Consequently, fault calculations made after execution of FLAT,CL ignore load currents in both pre-event and post event solutions.

In addition to setting the power system to flat-start conditions and deleting all load, FLAT,CL gives the option of setting all transformer ratios to nominal value, of ignoring all line-charging capacitance, and ignoring all other shunt elements in the positive and negative sequences. When deleting shunts, FLAT,CL *does not* delete shunts from the zero-sequence network.

The system *should not* be solved between execution of FLAT,CL and SEQD. A solution made after execution of FLAT,CL would not correspond to any realistic operating condition and the resulting generator internal source voltages would be no more meaningful than the uniform (1 + j0) values produced when SEQD follows FLAT,CL immediately.

Effect of Pre-Event Conditions on Fault Calculations

The dependence of fault calculations on the pre-event conditions is most simply illustrated by the small example shown in Figure 11.27, “Fault Calculations from Unloaded and Loaded Prefault Conditions”. In the first case shown, the generator is excited to rated (1 per unit) voltage and there is no load on the system. This corresponds to the flat-start condition with simplified system modeling where all loads, charging capacitances and shunt paths are ignored, and all generator internal voltage sources are equal to (1 + j0). The following fault currents are calculated for faults at the outer end of the transmission:

three-phase fault current

$I_f = E_1 / Z_1 = (1 + j0) / j0.8 = -j1.25$

single-phase fault current

$I_f = 3E_1 / (Z_0 + Z_1 + Z2) = (3 + j0) / j(0.0931 + 0.8 + 0.8) = -j1.772$

In the second case the pre-event condition has a load (P + jQ) = (1 + j0) at the outer end of the transmission and the voltage at the load point is still (1 + j0). The generator positive-sequence source voltage is now

$E_{source} = v_{load} + I_{load}Z_1$

$= (1 + j0) + (1 + j0)(j0.08)$

= (1 + j0.8)

= 1.2806 ∠ 38.66°

The three-phase fault current is still calculated readily as

$I_f = E_1 / Z_1$ = (1 + j0.8) / j0.8 = 1.6 ∠ -51.3

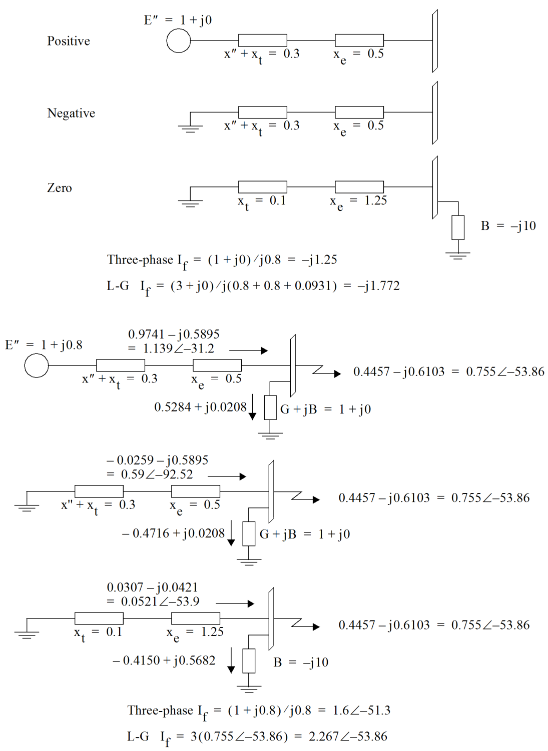

Figure 11.27. Fault Calculations from Unloaded and Loaded Prefault Conditions

The single-phase fault current is no longer given by the simple expression used previously because the load admittance is in parallel with the fault in the positive sequence. The positive- and negative-sequence Thevenin impedances at the point of the fault are given by combining impedance of (0 + j0.8) and (1 + j0) in parallel:

$Z_{1t} = Z_{2t}$ = 1 / (1 / (0 + j0.8) + (1 + j0))

= 0.6247 ∠ 51.34

= 0.39024 + j0.4878

The zero-sequence Thevenin impedance remains at j0.0931. The fault current is, then

$3E_{Thev} / (Z_{0t} + Z_{1t} + Z_{2t})$ = 3(1 + j0) / (2(0.39 + j0.4878) +j0.0931)

= 2.267 ∠ -53.86

This result is exactly (1 + j0.8) times the value of fault current (-j1.772) calculated above on the basis of open-circuit pre-event conditions. It could have been calculated, for this elementary example, from the Thevenin impedances of the unloaded system and the loaded pre-event source voltage as:

$I_f = 3(1 + j0.8) / j(0.8 + 0.8 + 0.0931) = 2.267 \angle -51.34$

This alternative approach of calculating loaded system fault currents by applying a pre-event generator source voltage corresponding to a loaded operating condition is only exact, as in the above example, when all generator source voltages are identical. This is not normally so. Nevertheless, it is common practice to estimate fault currents by using simplified modeling corresponding to unloaded pre-event conditions, and then scaling all calculated fault currents by a factor in the range of 1.15 to 1.3 to approximate the real condition in which generator internal source voltages are at their loaded values.

The practice of using scaling factors may be applied to fault currents calculated by PSS®E after the use of Activity FLAT,CL. This procedure is *not* automated by activities SEQD, SCMU, and SCOP, and must be handled manually. Results calculated by SCMU and SCOP, when the system model includes full-load details and the pre-event voltages in the working file are a power flow solution, *must not* be scaled; SCMU recognizes the exact individual pre-event internal source voltage of each generator as determined by activity SEQD.

11.3. Detailed Fault Analysis Calculations

11.3.1. Simulation of Unbalanced Conditions

Unbalanced fault analysis is handled by solving the three sequence networks simultaneously, interconnected as required, to represent the unbalanced condition of interest. The interconnection and solution of the sequence networks is handled by activity SCMU, which recognizes the unbalanced conditions shown in Figure 11.28, "Faults and Unbalances Allowed by PSS®E". The dialog of SCMU allows these applications:

1. Two line-to-ground (L-G) faults, as shown in Figure 11.28, "Faults and Unbalances Allowed by PSS®E"a.
2. Two line-to-line-to-ground (L-L-G) faults, as shown in Figure 11.28, "Faults and Unbalances Allowed by PSS®E"b.
3. One single-phase open fault in an isolated phase device, as shown in Figure 11.28, "Faults and Unbalances Allowed by PSS®E"c.
4. One two-phases open fault in an isolated phase device, as shown in Figure 11.28, "Faults and Unbalances Allowed by PSS®E"d.

These unbalances may be applied simultaneously at any bus involving any phase or phases; they need not represent faults. Because the impedances specified for all unbalances may range from zero to infinity, judicious choice of impedances and unbalances allows SCMU to handle a wide variety of fault, unbalanced load, and other abnormal system conditions. The following rules must be observed in applying unbalances:

1. A line-to-line fault is established by setting the ground impedance, Z_G, to an effectively infinite value (999 + j999). A value of one-half the desired line-to-line impedance must be entered for Z_F.
2. With the three-phase fault option, SCMU establishes a three-phase fault by the simultaneous use of one each of the available L-G and L-L-G faults.
3. Only one of the L-G or L-L-G unbalances may be placed at a point along a transmission line. Activity SCMU automatically assigns a dummy bus, number 99999, to the fault location. The line may be fed from both ends or one end, as shown in Figure 11.28, "Faults and Unbalances Allowed by PSS®E"e and Figure 11.28, "Faults and Unbalances Allowed by PSS®E"f.
4. The line or branch, where a line-end or in-line unbalance will be applied, must be in service in the power flow case before SEQD is run. Activity SCMU automatically opens the branch at one end if the open-end fault option is selected.
5. The single-phase and double-phase closed unbalances place new unbalanced branches in parallel with those already present in the power flow case in the working file. Setting up a case with one or two phases of a system component opened (or closed) requires that component be out-of-service in the power flow case before execution of SEQD.
6. The single- and double-phase closed unbalances are applicable to isolated phase devices such as series capacitors, series inductors, and grounded wye transformer windings, but are not applicable to transmission lines.
7. All unbalances applied in an execution of SCMU remain in effect through subsequent executions of SCOP. Each execution of SCMU or SEQD clears all previously applied unbalances, and deletes the dummy bus 99999 from the system.

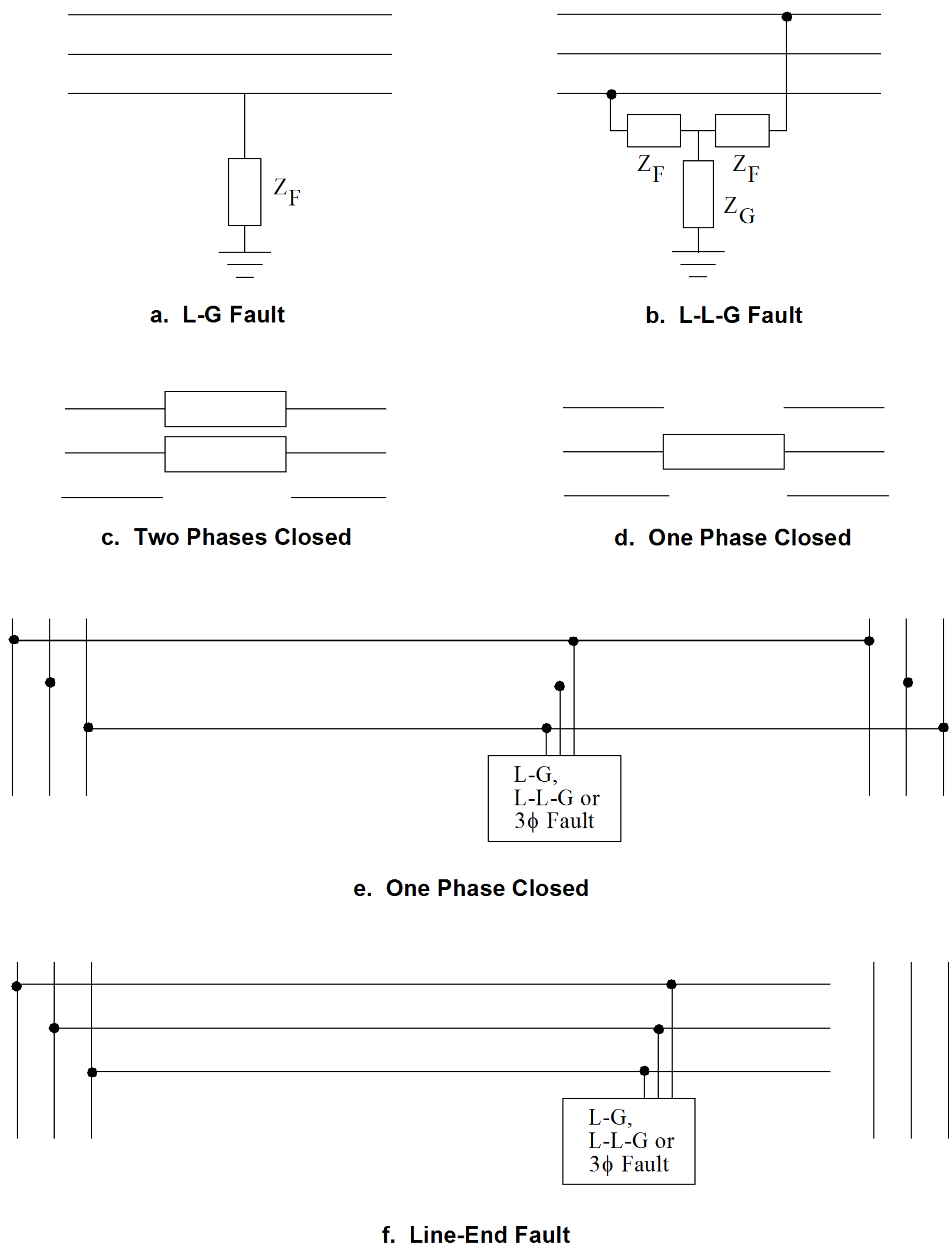

Figure 11.28. Faults and Unbalances Allowed by PSS®E

For in-line unbalances, the user is required to enter a distance factor specifying the distance of the fault from the from bus end of the line. This factor is equal to the distance from the from bus to the unbalance in per-unit terms of the total line length. The user is cautioned against the use of factors very close to zero or unity because these can give very low impedances between the from or to bus and the fault.

11.3.2. Fault Analysis Procedure

Detailed fault analysis is handled by activities SEQD, SCMU, SCOP, SQCH, and SQLI, which are analogous to the power flow activities covered in Chapter 6, *Basic Power Flow Activity Applications*. The correspondence between detailed fault analysis and power flow activities is shown by Table 11.3, "Correspondence Between Fault Analysis and Power Flow Activities". The overall procedure of fault analysis is summarized in Figure 11.29, "Basic Procedure for Detailed Fault Analysis Needed for Each Step are Shown in Parenthesis" and in more detail in Figure 11.30, "General Fault Analysis Procedure Activities Needed for Each Step are Shown in Parenthesis".

Table 11.3. Correspondence Between Fault Analysis and Power Flow Activities

Fault Analysis		Power Flow	
Activity	Prerequisite	Activities	Prerequisites
RESQ	Positive-sequence case already in working case.	READ	
TRSQ	Positive-sequence network in working case with (some) sequence data already included.	Reading Power Flow Data Additions from the Terminal	Nonnull working case.
SQLI		LIST	
SQCH	Positive-sequence case including fault analysis data already in working case.	CHNG	All system elements previously entered into working case by READ.
SEQD	Valid fault analysis data in working case.	CONG, CONL, ORDR , FACT	Valid power flow case in working case.
SCMU	Successful completion of SEQD for current network status.	CHNG, TYSL, SOLV , FNSL, NSOL, MSLV	Successful completion of ORDR and FACT for current network status.
SCOP	Successful completion of SCMU .	POUT	Successful completion of power flow solution.

Fault analysis data should be incorporated into a power flow saved case at the earliest possible opportunity. Doing this ensures that the data for all sequences is always handled together, and minimizes the possibility of error due to incorrect updating of the fault analysis data to match power flow data changes.

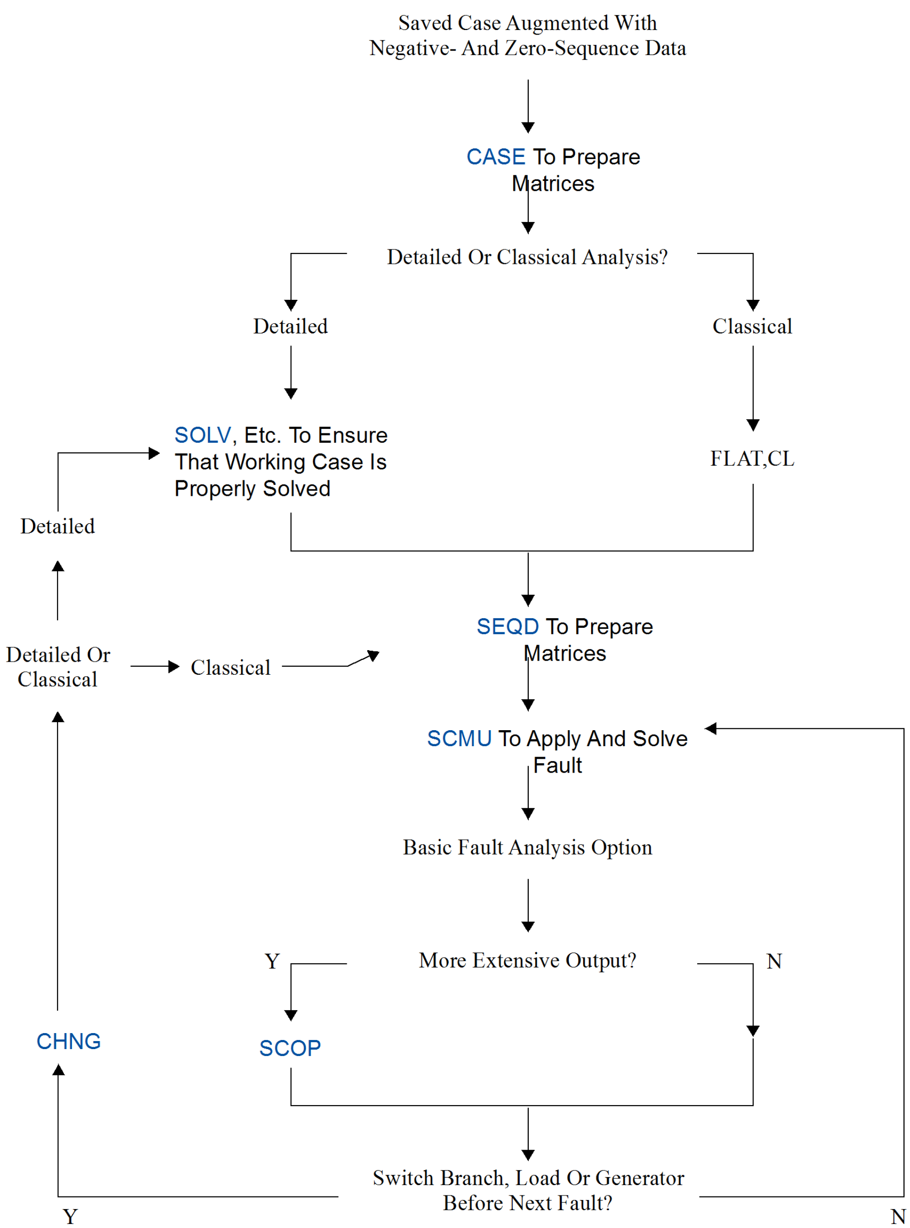

Figure 11.29. Basic Procedure for Detailed Fault Analysis Needed for Each Step are Shown in Parenthesis

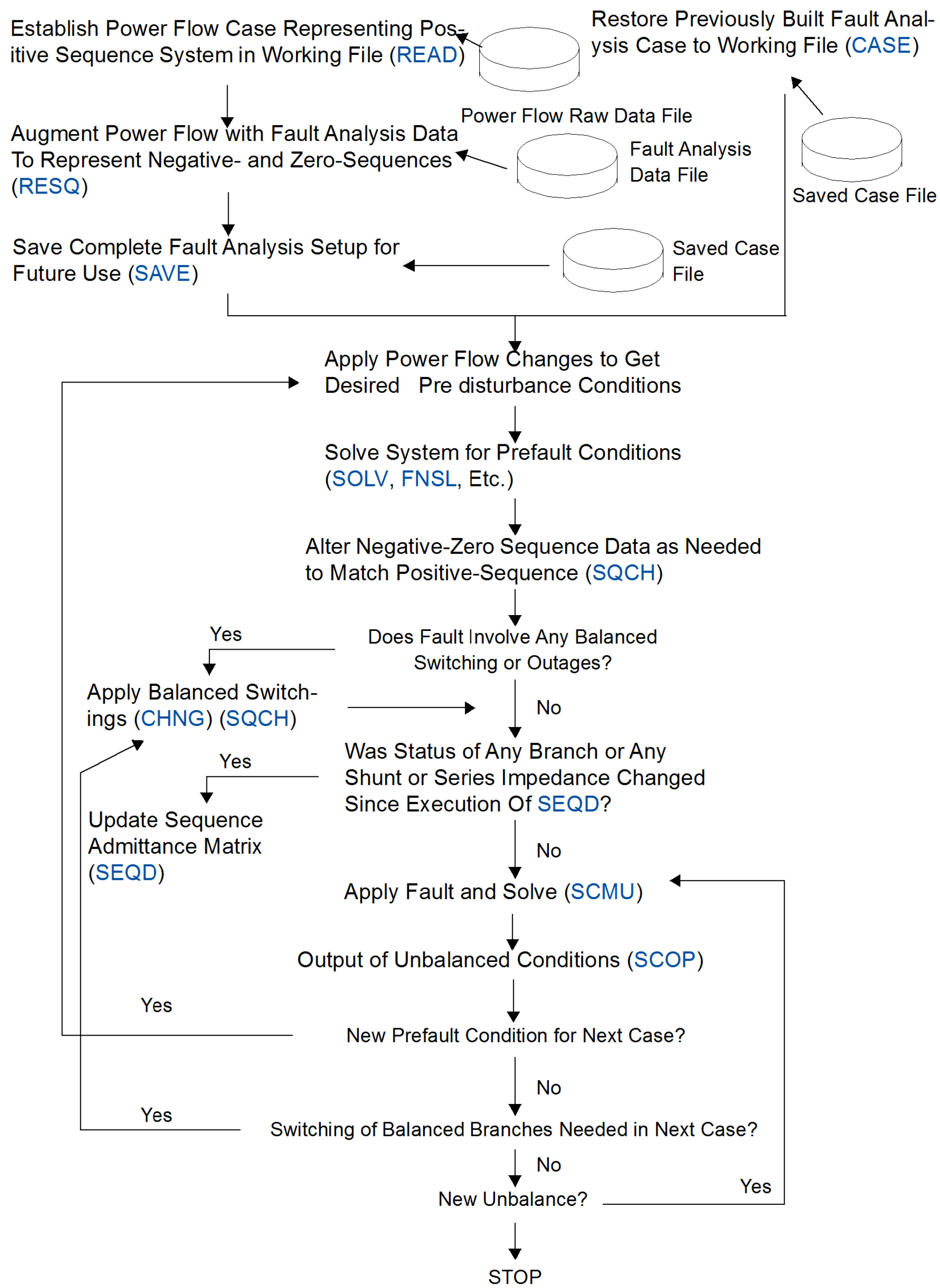

Figure 11.30. General Fault Analysis Procedure Activities Needed for Each Step are Shown in Parenthesis

After the system positive-sequence and fault analysis data have been properly coordinated and saved, the fault analysis process is a direct parallel of the power flow switching study procedure outlined in Chapter 8, *Equivalents*. The principal steps in a fault analysis are:

1. Set up and solve the power flow case for the preswitching system condition to provide the basis for initializing all generators and conversion of loads to constant admittance.

2. Change branch and generator status as required, or adjust loads and shunts, to produce the desired postswitching system conditions, excluding unbalances. This task may require both the CHNG and SQCH activities if the switching changes the negative- and zero-sequence characteristics of loads or the status of transformers.

3. Establish all required sequence network admittance matrices for the postswitching condition by executing activity SEQD.

4. Apply all unbalances that are to exist in the postswitching condition, and solve the resulting interconnected sequence networks for the complete set of system voltages. This step is handled by activity SCMU.

5. Use activity SCOP to obtain output as required.

The relationship between Steps 2 and 3 is important, and is illustrated in Figure 11.31, "Bus Fault Prior to Clearance of Incoming Circuits" through Figure 11.33, "Series Capacitor Bank with L-G Fault on B-Phase and Protective Gap Flashed Over on B-Phase". Figure 11.31, "Bus Fault Prior to Clearance of Incoming Circuits" shows a transmission substation with a L-G fault prior to clearance of any incoming circuits. Step 2 would be skipped in applying this fault because the switching is only a fault application, which is handled as a bus L-G unbalance in Step 3. Figure 11.32, "Bus Fault After Primary Clearing of Local Circuit Breakers" shows a later stage in the development of the same fault. Here breakers 502, 505 and 506 have opened, but breaker 503 has failed to trip, leaving the fault as a line-end fault on circuit 3. This situation requires the use of CHNG in Step 2 to open circuit 6. Following this step, the fault would be applied in step 3 as a line-end L-G unbalance on circuit 3.

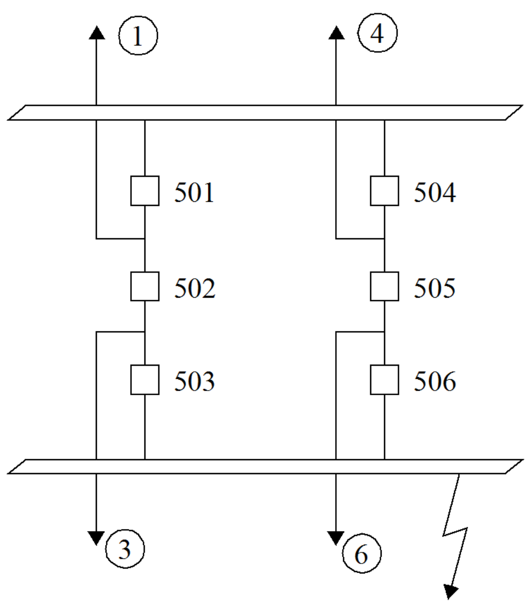

Figure 11.31. Bus Fault Prior to Clearance of Incoming Circuits

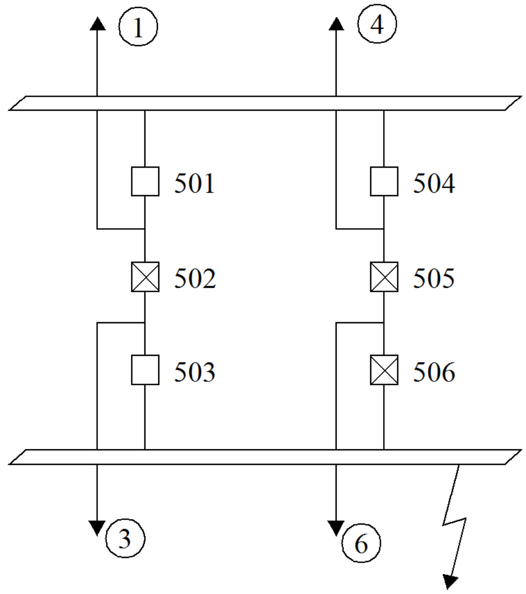

Figure 11.32. Bus Fault After Primary Clearing of Local Circuit Breakers

Another situation requiring both Step 2 and Step 3 is shown in Figure 11.33, “Series Capacitor Bank with L-G Fault on B-Phase and Protective Gap Flashed Over on B-Phase”. Here the B-phase of a series capacitor bank has been subject to an L-G fault and has its protective spark gap flashed over. Step 2 in this case would use CHNG to open the capacitor branch 761-762. Step 3 would then require the application of three unbalances: L-G fault on B-phase of bus 761; B-phase closed between 761 and 762 with a small impedance, i.e., (0. + j0.00001) per unit; and A- and C-phases closed between 761 and 762 with impedance of $(0 - jX_c)$ per unit.

Finally, if the protective gap was not flashed over, Step 2 would be skipped and Step 3 would require only the application of the L-G fault.

Activity SEQD establishes a complete set of sequence network models for a given network configuration. These models are preserved by SCMU and SCOP so that it is necessary to re-run activity SEQD only if changes have been made with CHNG or SQCH.

SEQD *must* be run after any branch status, branch data, shunt data, or load data has been changed by CHNG or SQCH.

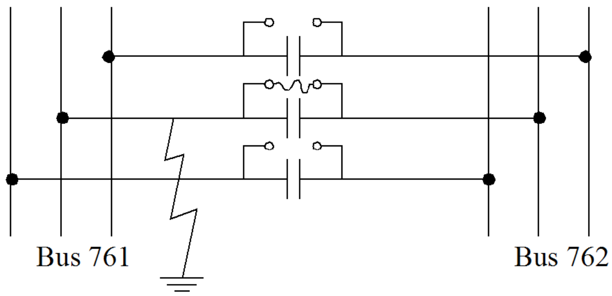

Figure 11.33. Series Capacitor Bank with L-G Fault on B-Phase and Protective Gap Flashed Over on B-Phase

11.3.3. Detailed Fault Analysis Outputs

Formats

The output formats of activity SCMU and SCOP are shown in Figure 11.34, "Output Formats of Activity SCMU". The user has the option of getting the output in either rectangular or polar coordinates. Activity OPTN also gives the user the choice of output in either physical units (if kV has been specified) or per unit.

Thevenin Impedance

The first output of each fault solution made by activity SCMU is a summary of the system Thevenin impedance as seen at each bus where an unbalance is implied. Figure 11.34, "Output Formats of Activity SCMU"a shows that each of buses 99999 and 300 is involved in some form of unbalance. The presence of bus 99999 in the list of faulted buses indicates that one unbalance has been applied at a line-end or in-line location.

Each Thevenin impedance is the system short circuit self-impedance that would be observed at the bus with no disturbance applied at any other. In Figure 11.34, "Output Formats of Activity SCMU"a, for example, the negative-sequence self-impedance at bus 300 is (0.09994 + j0.39648).

Branch and Bus Conditions

Activity SCMU and SCOP print out bus voltages and branch flows in terms of both symmetrical component and phase quantities. Both sets of quantities appear in all output, even though the phase quantities are not meaningful in certain situations, as outlined in notes 1 and 2 of the section called "Representation of Transformer Phase Shift in Part of the System".

Bus Voltage

The format of bus voltage is shown by Figure 11.34, "Output Formats of Activity SCMU"b. The first line shows the bus zero-, positive-, and negative-sequence voltages in rectangular coordinates. The second line gives the bus phase voltages in rectangular coordinates. The user could have obtained polar coordinates by selecting this option via activity OPTN. All bus voltage values are per unit of base line-to-ground voltage. The phase voltages are line-to-ground values.

Series Branch Current

Figure 11.34, "Output Formats of Activity SCMU"c shows the current flowing in circuit 1 between buses 200 and 300 in the 200-to-300 direction. All currents are per unit of base phase current.

Current in Applied Disturbances

Activities SCMU and SCOP provide output of the currents flowing at the points where unbalances are applied in two formats as shown in Figure 11.35, "Output of Fault Current from Activity SCMU Corresponding to Figure 11.27, "Fault Calculations from Unloaded and Loaded Prefault Conditions"", which corresponds to the second case of Figure 11.27, "Fault Calculations from Unloaded and Loaded Prefault Conditions". The output provides the following data:

1. The branch current arriving at bus 3.

2. The sum of contributions at bus 3, which is the same as the current in branch 2-3.

3. The fault current at bus 3.

```
 SEQUENCE THEVENIN IMPEDANCES AT FAULTED BUSES:

  BUS    NAME   BSKV          ZERO               POSITIVE             NEGATIVE
  300 EAST     33.0     0.00319  0.14766    0.17757  0.48540    0.09994  0.39648
99999 DUMMYBUS 138      0.01357  0.14492    0.15619  0.38618    0.08430  0.29649
```

a. Thevenin Impedance

```
SEQUENCE      RE(V0)    IM(V0)    RE(V+)    IM(V+)    RE(V-)    IM(V-)    RE(3V0)   IM(3V0)
PHASE         RE(VA)    IM(VA)    RE(VB)    IM(VB)    RE(VC)    IM(VC)

 300  (P.U.) -0.1202    0.0268    0.1901   -0.0624   -0.0698    0.0357   -0.3607    0.0803
EAST   33.0   0.0000    0.0000   -0.2654   -0.1849   -0.0954    0.2652
```

b. Bus Voltage

```
SEQUENCE      RE(I0)    IM(I0)    RE(I+)    IM(I+)    RE(I-)    IM(I-)    RE(3I0)   IM(3I0)
PHASE         RE(IA)    IM(IA)    RE(IB)    IM(IB)    RE(IC)    IM(IC)

FROM    200 1 -0.0369   -0.0500   -0.0371   -0.1393   -0.0551   -0.2401   -0.1108   -0.1499
WEST     33.0 -0.1292   -0.4294    0.0965    0.1242   -0.0781    0.1553

FROM    400 1 -0.1698   -0.7630   -0.1382   -0.7048   -0.1619   -0.5589   -0.5093   -2.2891
EAST      138 -0.4698   -2.0267   -0.1461   -0.1517    0.1066   -0.1106
```

c. Branch Current

```
SUM OF CONTRIBUTIONS INTO BUS   300 [EAST    33.0]:

  300         -0.2067   -0.8130   -0.1753   -0.8441   -0.2170   -0.7990   -0.6201   -2.4389
EAST     33.0 -0.5989   -2.4561   -0.0496   -0.0275    0.0285    0.0447

CONTRIBUTIONS EQUIVALENT POSITIVE SEQUENCE ADMITTANCE    0.4844   -4.2819
```

d. Sum of Current Contributions

```
SHUNT + LOAD CURRENT AT BUS   300 [EAST    33.0]:

  300          0.0000    0.0000    0.0314   -0.0311   -0.0103    0.0140    0.0000    0.0000
EAST     33.0  0.0211   -0.0172   -0.0496   -0.0275    0.0285    0.0447
```

e. Current in Applied Unbalances

Figure 11.34. Output Formats of Activity SCMU

The sum of contributions shown by activities SCMU and SCOP is always calculated as:

$I_{\text{sum of contribs}} = \Sigma\, I_{\text{branch}} + I_{\text{gen}}$

where

$\Sigma\ I_{branch}$

Current flowing into the bus via all connected branches.

I_{gen}

Generator current arriving at the bus.

The SUM OF CONTRIBUTIONS printout gives the net current flowing from the bus to ground through the load connected to the bus, the shunt admittance elements connected to the bus, and all unbalances applied at the bus.

In the case shown in Figure 11.35, "Output of Fault Current from Activity SCMU Corresponding to Figure 11.27, "Fault Calculations from Unloaded and Loaded Prefault Conditions"" and Figure 11.27, "Fault Calculations from Unloaded and Loaded Prefault Conditions", for example, the sum of contributions shows a zero-sequence value of (0.0307 –j0.0421), which consists of fault current of (0.4457 –j0.6103) and a current of (0.4150 – j0.5682) flowing *from* ground through the zero-sequence shunt admittance. The zero-sequence current flowing into the leads of a grounded-wye transformer is handled as branch current when the transformer connection codes are used, and is not a part of the net current flowing to ground.

```
FROM     2     1          0.0307     -0.0421     0.9739    -0.5897    -0.0261    -0.5895
                          0.9786     -1.2213    -0.4434    -0.3185    -0.4430     1.4135
```

Current arriving at Bus 3 from Bus 2

```
SUM OF CONTRIBUTIONS INTO BUS     3[               ]:

3                         0.0307     -0.0421     0.9739    -0.5897    -0.0261    -0.5895
                          0.9786     -1.2213    -0.4434    -0.3185    -0.4430     1.4135
```

Total current flowing to ground at Bus 3

```
CONTRIBUTIONS EQUIVALENT POSITIVE SEQUENCE ADMITTANCE    1.7968    -1.1861

FAULT CURRENT AT BUS    3[               ]:

3                         0.4457     -0.6103     0.4455    -0.6103     0.4455    -0.6103
                          1.3365     -1.8310     0.0000     0.0000     0.0000     0.0000

POSITIVE SEQUENCE FAULT ADMITTANCE   0.7968    -1.1862
```

Current In L-G fault at Bus 3

Figure 11.35. Output of Fault Current from Activity SCMU Corresponding to Figure 11.27, "Fault Calculations from Unloaded and Loaded Prefault Conditions"

For example, the application of a simple L-G fault at a bus having a load in the positive sequence, a grounded-wye transformer represented by a connection code of 1, and no other directly connected grounded device will show, in its sum of contributions:

- Load current plus fault current in the entries for the positive and negative sequences and the faulted phase.
- Fault current in the entry for the zero-sequence.
- Load current in the entries for the nonfaulted phases.

Addition of a grounded-wye shunt capacitor bank at the bus would result in SUM OF CONTRIBUTIONS entries containing:

- Load current plus fault current plus shunt capacitor current in the entries for the positive and negative sequences and the faulted phase.
- Fault current plus capacitor current in the entry for the zero-sequence.
- Load current plus capacitor current in the entries for the nonfaulted phases.

Activities SCMU and SCOP show the *sum of contributions* at every bus for which output is displayed. *Fault current* is displayed only for the bus at which an L-G or L-L-G fault is applied, and only when this fault is the *only* unbalance applied on the system. Fault current is displayed only by activity SCMU. When fault current is not displayed the actual current in the applied unbalance must be deduced by drawing out a diagram like that in Figure 11.27, "Fault Calculations from Unloaded and Loaded Prefault Conditions".

Apparent Impedance and Admittance

Activity SCOP may calculate and display the apparent impedance and admittance looking down each branch. The display format is the same as for current and voltage except that the header lines include *Z* or *Y* as appropriate.

The first line of this sample output shows the sequence impedances looking down the branch in rectangular form. The second line shows the phase impedances looking down the branch in polar form.

These apparent impedances are defined as:

$Z_{seq} = v_{seq} / i_{seq}$

$Z_{phase} = v_{phase} / i_{phase}$

where the sequence and phase currents are the total currents flowing into the branch including line-charging capacitance current and current flowing into line-connected devices.

Apparent admittances are defined as the reciprocal of the apparent impedances, and all impedances and admittances are expressed, per unit, relative to system base values. Infinite impedance is printed as the value 999 per unit.

Equivalent Fault Admittance

For L-G and L-L-G faults, activity SCMU prints out a value of equivalent fault admittance, expressed in per unit/rectangular form, relative to system base values. In the L-G fault example shown by Figure 11.35, "Output of Fault Current from Activity SCMU Corresponding to Figure 11.27, "Fault Calculations from Unloaded and Loaded Prefault Conditions"" and Figure 11.27, "Fault Calculations from Unloaded and Loaded Prefault Conditions", the equivalent fault admittance (0.7968 – j1.1862) is equal to $1/(Z_2 + Z_0)$ where Z_2 and Z_0 are the Thevenin impedances of the negative- and zero-sequence networks at the faulted bus. Applying this shunt admittance as a fault in the dynamic simulation activity ALTR will allow activity RUN to give a correct computation of the generator positive-sequence currents during this fault.

- For this equivalent fault admittance to be valid, *all* unbalances must be located at the same bus and only L-G and L-L-G unbalances may be involved.
- The equivalent fault admittance is printed in association with both the sum of contributions output and the fault current output. When associated with sum of contributions, this equivalent admittance represents the net effect of load and unbalances at a node. When associated with fault current this admittance represents only the effect of the unbalances at the bus.

Sense of Current Flow

The sense of current flow in reports from PSS®E is always in the direction from the first mentioned bus to the second mentioned bus. Activity SCMU, unlike the power flow output Activities (POUT, LOUT, LIST, etc.) arranges a block of output to show all branch currents *arriving at a selected bus*. Activity SCOP follows conventional power flow practice and blocks output to show all currents *leaving a selected bus*.

Activity SCMU

In addition to its detailed output, activity SCMU summarizes its calculations of simple single-fault cases in a file named SMRYSC. Fault current results are appended to the file SMRYSC every time activity SCMU completes a calculation in which the only unbalance is a single fault, either three-phase, L-G, or L-L-G at any location and the fault impedance is (0 + j0).

The file SMRYSC continues to grow until the user deletes it; a fresh file will open with the next execution of SCMU. The format of file SMRYSC is shown in Figure 11.36, “File SMRYSC – Summary of Results from Activity SCMU (Corresponds to Figure 11.34, “Output Formats of Activity SCMU” and Figure 11.46, “Use of Full Detail in Calculating Line Fault with One End Open (Sheet 1 of 4)”)”. Each two line entry specifies the fault location and type, the sequence components of fault current, and the phase components of fault current.

The summary file contains *no* record of the system model used in calculating the fault currents. Hence, it is advisable to change the name of the file from SMRYSC to something associated with the saved case filename each time fault analysis work is shifted to a new system model.

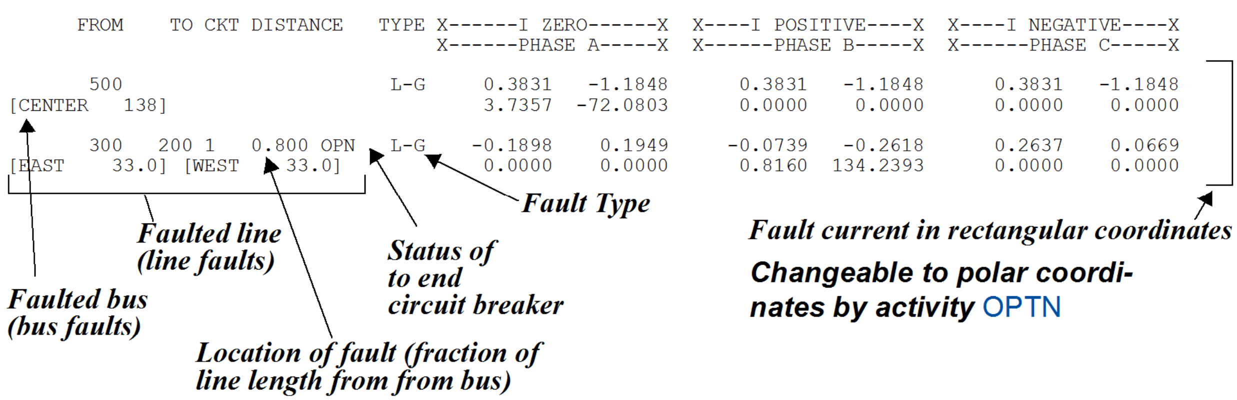

Figure 11.36. File SMRYSC – Summary of Results from Activity SCMU (Corresponds to Figure 11.34, “Output Formats of Activity SCMU” and Figure 11.46, “Use of Full Detail in Calculating Line Fault with One End Open (Sheet 1 of 4)”)

11.3.4. Examples

Initial Case – Full Detail

Figure 11.37, “Dialog for Example 10.3.4.1 - L-G Fault at Bus 500 (Sheet 1 of 2)” shows the dialog for the application of fault analysis activities to calculate the line-to-ground fault current for an L-G fault at bus 500 of the system model of Figure 11.15, “Sample System for Fault Analysis” and the pre-event condition of Figure 11.20, “Pre-Event Power Flow with Transformer Phase Shift Included”. The activity sequence is

CASE, UFSQA.sav

Recover the system model and pre-event solution.

SOLV

Verify that the working file contains a solved case.

SEQD

Prepare the required sequence network matrices.

SCMU

Apply and solve the fault case.

The only output used in this example is provided by activity SCMU showing conditions at the point of the applied unbalance. The sum-of-contributions at bus 500 is:

(0.6232 – j1.1714) per unit in the positive sequence.

(0.1337 – j0.3409) per unit in the zero-sequence.

(0.4751 – j1.3098) per unit in the a-phase.

(-0.1396 + j0.2128) per unit in the b-phase.

(-0.1458 + j0.6297) per unit in the c-phase.

and the fault current is

(0.3831 – j1.1848) per unit in the zero-sequence.

(1.1494 – j3.5544) per unit in the a-phase.

The zero-sequence voltage at bus 500 is -(0.0844 + j0.0249) and the a-phase voltage is, of course, (0 + j0). The b-and c-phase components of sum-of-contributions are current flowing into the 15-Mvar ungrounded shunt capacitor bank and the current flowing into the leads of the grounded wye 138-kV winding of the load transformer.

The difference between the zero-sequence components of sum-of-contributions and fault current is (–0.249 + j0.844), the zero-sequence bus voltage of –(0.0844 + j0.0249) and the zero-sequence shunt admittance at bus 500 of –j10. The effect of the line-connected shunt reactor on circuit 100-500 is accommodated in the calculation of branch current and hence does not appear as a difference between sum of contributions and fault current at bus 500. The zero-sequence situation at bus 500 is summarized by Figure 11.39, “Zero-Sequence Conditions at Bus 500 as Shown in Figure 11.25, “Augmentation of Established Power Flow Case to Include Negative- and Zero-Sequence Networks (Sheet 1 of 2)””.

Reduced Modeling Detail

The previous example used the fullest modeling detail allowed by PSS®E and, accordingly, its results showed both fault and load current in branch flows. It is often convenient to work with system models that ignore pre-event loading and show only fault current in the results from activity SCMU.

```
ACTIVITY? case ufsqa
```

Pick up saved case including transformer phase shift

```
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CASE ufsqa.sav WAS SAVED ON THU OCT 07, 1993  10:29

ACTIVITY? solv
```

Verify that case is solved for pre-event conditions

```
ITER DELTAV/TOL  BUS   REAL(DELTAV)   IMAG(DELTAV)
   1      0.560  600    -0.4988E-04    -0.2546E-04

REACHED TOLERANCE IN   1 ITERATIONS

LARGEST MISMATCH:    0.00 MW    0.03 MVAR     0.03 MVA-BUS   500 [CENTER   138]
SYSTEM TOTAL ABSOLUTE MISMATCH:               0.09 MVA

ACTIVITY? seqd
```

Activity SEQD to prepare sequence networks for solution

```
DIAGONALS =      6  OFF-DIAGONALS =      8  MAX SIZE =    12
POS. SEQUENCE: DIAGONALS =      6  OFF-DIAGONALS =      8
NEG. SEQUENCE: DIAGONALS =      6  OFF-DIAGONALS =      8
DIAGONALS =      6  OFF-DIAGONALS =     10  MAX SIZE =    20
ZERO SEQ. GEN. IMPEDANCE IGNORED AT BUS   100 [WEST GEN 138] MACH 1--USING XT
ZERO SEQ. GEN. IMPEDANCE IGNORED AT BUS   100 [WEST GEN 138] MACH 2--USING XT
BUS    600 [EAST GEN12.5] ISOLATED IN ZERO SEQUENCE
ZERO SEQUENCE: DIAGONALS =      6  OFF-DIAGONALS =     10

ACTIVITY? scmu
```

Activity SCMU to apply and solve

```
ENTER UNBALANCE CODE:
 0 FOR NO MORE           1 FOR FIRST L-G
 2 FOR SECOND L-G        3 FOR FIRST L-L-G
 4 FOR SECOND L-L-G      5 FOR 1 PHASE CLOSED
 6 FOR 2 PHASES CLOSED   7 FOR THREE PHASE FAULT
 8 FOR ONE END OPENED    9 FOR IN LINE SLIDER: 1
```

Select L-G fault

```
ENTER BUS NUMBER (0 FOR NEW FAULT CODE, -1 FOR NO MORE): 500
```

Apply it at bus 500

```
ENTER PHASE (1, 2 OR 3): 1
```

Fault on A-phase.

```
ENTER FAULT IMPEDANCE (R,X): 0. 0.
```

Fault impedance is (0 +j0)

```
ENTER UNBALANCE CODE:
 0 FOR NO MORE           1 FOR FIRST L-G
 2 FOR SECOND L-G        3 FOR FIRST L-L-G
 4 FOR SECOND L-L-G      5 FOR 1 PHASE CLOSED
 6 FOR 2 PHASES CLOSED   7 FOR THREE PHASE FAULT
 8 FOR ONE END OPENED    9 FOR IN LINE SLIDER: 0
```

No more unbalances in this event

```
UNBALANCES TO BE APPLIED:

LINE TO GROUND FAULT AT BUS   500 [CENTER   138]   PHASE 1
  L-G Z =    0.0000       0.0000

ENTER 1 IF OK, 0 TO RE-SPECIFY UNBALANCES, -1 TO EXIT ACTIVITY: 1
```

Yes! That's what I want

Figure 11.37. Dialog for Example 10.3.4.1 - L-G Fault at Bus 500 (Sheet 1 of 2)

```
     PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS®E      THU OCT 07, 1993  13:38
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UNBALANCES APPLIED:

LINE TO GROUND FAULT AT BUS    500 [CENTER    138]    PHASE 1
  L-G Z =    0.0000        0.0000


              SEQUENCE THEVENIN IMPEDANCES AT FAULTED BUSES:

  BUS    NAME  BSKV          ZERO               POSITIVE            NEGATIVE
  500 CENTER   138    0.00179  0.07065    0.16698  0.38443    0.09326  0.29771

LINE TO GROUND FAULT AT BUS    500 [CENTER    138]:

SEQUENCE            RE(V0)    IM(V0)    RE(V+)    IM(V+)    RE(V-)    IM(V-)   RE(3V0)   IM(3V0)
PHASE               RE(VA)    IM(VA)    RE(VB)    IM(VB)    RE(VC)    IM(VC)

  500   (P.U.)     -0.0844   -0.0249    0.4729    0.0285   -0.3885   -0.0036   -0.2532   -0.0748
CENTER    138      0.0000    0.0000   -0.0988   -0.7833   -0.1544    0.7085

SEQUENCE            RE(I0)    IM(I0)    RE(I+)    IM(I+)    RE(I-)    IM(I-)   RE(3I0)   IM(3I0)
PHASE               RE(IA)    IM(IA)    RE(IB)    IM(IB)    RE(IC)    IM(IC)

FROM    100 1       0.0705   -0.1852    0.2969   -0.5962    0.1004   -0.6070    0.2114   -0.5555
WEST GEN 138       0.4677   -1.3883   -0.1188    0.2463   -0.1375    0.5866

FROM    400 1       0.0632   -0.1558    0.3263   -0.5752    0.0856   -0.5788    0.1897   -0.4673
EAST      138      0.4751   -1.3098   -0.1396    0.2128   -0.1458    0.6297


SUM OF CONTRIBUTIONS INTO BUS    500 [CENTER    138]:

  500               0.1337   -0.3409    0.6232   -1.1714    0.1860   -1.1858    0.4011   -1.0227
CENTER    138      0.9429   -2.6981   -0.2584    0.4591   -0.2833    1.2163

CONTRIBUTIONS EQUIVALENT POSITIVE SEQUENCE ADMITTANCE    1.1643   -2.5475


SHUNT + LOAD CURRENT AT BUS    500 [CENTER    138]:

  500              -0.2494    0.8439    0.2400    0.0134   -0.1972   -0.0009   -0.7483    2.5317
CENTER    138     -0.2065    0.8564   -0.2584    0.4591   -0.2833    1.2163


FAULT CURRENT AT BUS    500 [CENTER    138]:

  500               0.3831   -1.1848    0.3831   -1.1848    0.3831   -1.1848    1.1494   -3.5545
CENTER    138      1.1494   -3.5545    0.0000    0.0000    0.0000    0.0000

POSITIVE SEQUENCE EQUIVALENT FAULT ADMITTANCE     0.6568   -2.5453
```

A-phase fault current
= 3.73 —72 = (1.15 – j3.55)

Figure 11.38. Dialog for Example 10.3.4.1 - L-G Fault at Bus 500 (Sheet 2 of 2)

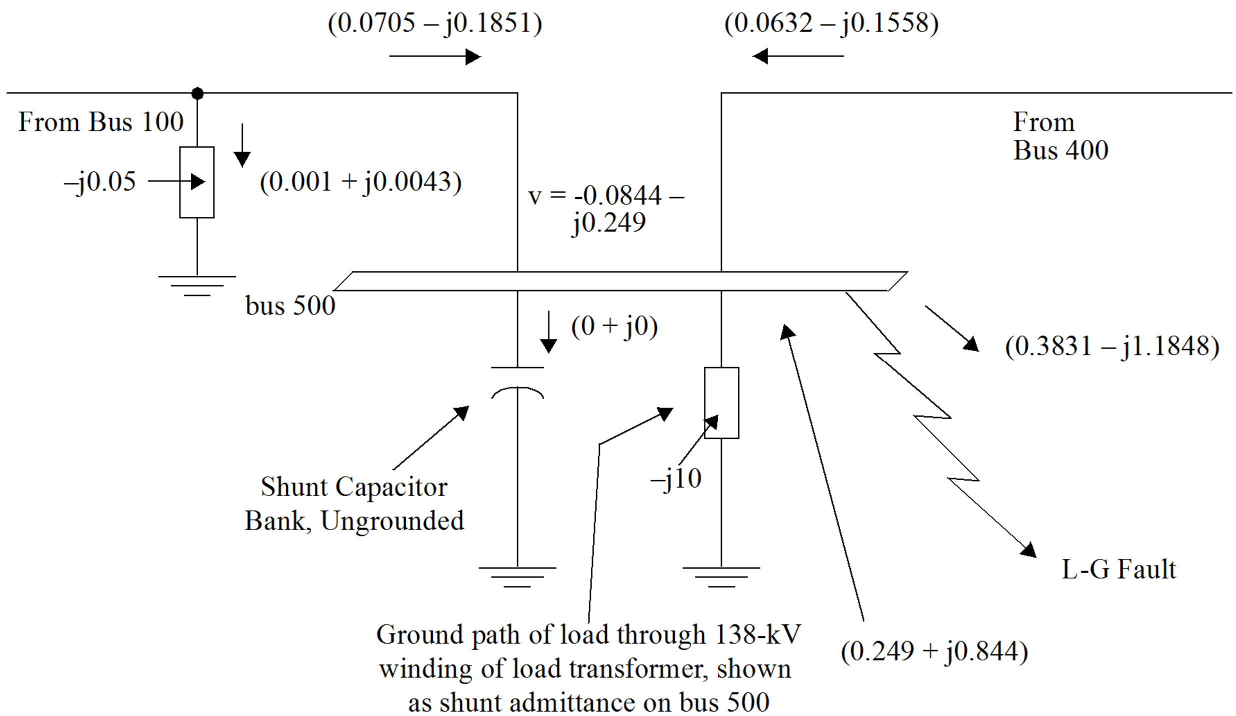

Figure 11.39. Zero-Sequence Conditions at Bus 500 as Shown in Figure 11.25, "Augmentation of Established Power Flow Case to Include Negative- and Zero-Sequence Networks (Sheet 1 of 2)"

```
ACTIVITY? flat,cl

ENTER 1 TO SET TAP RATIOS TO UNITY: 1

ENTER 1 TO SET CHARGING TO ZERO: 1

ENTER 1 TO SET SHUNTS TO ZERO IN POSITIVE SEQUENCE
      2 TO SET SHUNTS TO ZERO IN ALL SEQUENCES: 1

ACTIVITY? seqd
DIAGONALS =       6  OFF-DIAGONALS =      8  MAX SIZE =    12
POS. SEQUENCE: DIAGONALS =      6  OFF-DIAGONALS =     8
NEG. SEQUENCE: DIAGONALS =      6  OFF-DIAGONALS =     8
DIAGONALS =       6  OFF-DIAGONALS =     10  MAX SIZE =    20
ZERO SEQ. GEN. IMPEDANCE IGNORED AT BUS    100 [WEST GEN 138] MACH 1--USING XT
ZERO SEQ. GEN. IMPEDANCE IGNORED AT BUS    100 [WEST GEN 138] MACH 2--USING XT
BUS    600 [EAST GEN12.5] ISOLATED IN ZERO SEQUENCE
ZERO SEQUENCE: DIAGONALS =      6  OFF-DIAGONALS =    10

ACTIVITY? scmu

ENTER UNBALANCE CODE:
 0 FOR NO MORE           1 FOR FIRST L-G
 2 FOR SECOND L-G        3 FOR FIRST L-L-G
 4 FOR SECOND L-L-G      5 FOR 1 PHASE CLOSED
 6 FOR 2 PHASES CLOSED   7 FOR THREE PHASE FAULT
 8 FOR ONE END OPENED    9 FOR IN LINE SLIDER: 1

ENTER BUS NUMBER (0 FOR NEW FAULT CODE, -1 FOR NO MORE): 500
ENTER PHASE (1, 2 OR 3): 1
ENTER FAULT IMPEDANCE (R,X): 0 0

ENTER UNBALANCE CODE:
 0 FOR NO MORE           1 FOR FIRST L-G
 2 FOR SECOND L-G        3 FOR FIRST L-L-G
 4 FOR SECOND L-L-G      5 FOR 1 PHASE CLOSED
 6 FOR 2 PHASES CLOSED   7 FOR THREE PHASE FAULT
 8 FOR ONE END OPENED    9 FOR IN LINE SLIDER: 0

UNBALANCES TO BE APPLIED:

LINE TO GROUND FAULT AT BUS    500 [CENTER    138]    PHASE 1
  L-G Z =    0.0000         0.0000

ENTER 1 IF OK, 0 TO RE-SPECIFY UNBALANCES, -1 TO EXIT ACTIVITY: 1
```

Activity FLAT,CL to reduce system modeling to simple

Re-run SEQD ***because sequence networks have***

Activity SCMU ***to reapply L-G fault at***

As in Figure 11-31

Figure 11.40. Dialog to Recalculate L-G Fault at Bus 500 with Simplified System Modeling (Sheet 1 of 2)

```
     PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS®E      THU OCT 07, 1993  13:40
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UNBALANCED FAULT ANALYSIS EXAMPLE

UNBALANCES APPLIED:

LINE TO GROUND FAULT AT BUS   500 [CENTER   138]   PHASE 1
  L-G Z =    0.0000       0.0000


              SEQUENCE THEVENIN IMPEDANCES AT FAULTED BUSES:

  BUS   NAME  BSKV          ZERO              POSITIVE            NEGATIVE
  500 CENTER   138    0.00184  0.07012    0.01000  0.48333    0.01000  0.33333

LINE TO GROUND FAULT AT BUS   500 [CENTER   138]:

SEQUENCE          RE(V0)    IM(V0)    RE(V+)    IM(V+)    RE(V-)    IM(V-)   RE(3V0)   IM(3V0)
PHASE             RE(VA)    IM(VA)    RE(VB)    IM(VB)    RE(VC)    IM(VC)

  500  (P.U.)    -0.0791    0.0001    0.4550   -0.0021   -0.3759    0.0020   -0.2372    0.0004
CENTER   138      0.0000    0.0000   -0.1222   -0.7194   -0.1150    0.7198

SEQUENCE          RE(I0)    IM(I0)    RE(I+)    IM(I+)    RE(I-)    IM(I-)   RE(3I0)   IM(3I0)
PHASE             RE(IA)    IM(IA)    RE(IB)    IM(IB)    RE(IC)    IM(IC)

FROM   100 1      0.0139   -0.1823    0.0139   -0.5635    0.0139   -0.5635    0.0417   -0.5469
WEST GEN 138      0.0417   -1.3093    0.0000    0.3812    0.0000    0.3812

FROM   400 1      0.0152   -0.1539    0.0139   -0.5635    0.0139   -0.5635    0.0455   -0.4617
EAST     138      0.0429   -1.2809    0.0013    0.4096    0.0013    0.4096


SUM OF CONTRIBUTIONS INTO BUS   500 [CENTER   138]:

  500             0.0291   -0.3362    0.0278   -1.1270    0.0278   -1.1270    0.0872   -1.0086
CENTER   138      0.0846   -2.5902    0.0013    0.7908    0.0013    0.7908

CONTRIBUTIONS EQUIVALENT POSITIVE SEQUENCE ADMITTANCE    0.0727   -2.4765


SHUNT + LOAD CURRENT AT BUS   500 [CENTER   138]:

  500             0.0013    0.7908    0.0000    0.0000    0.0000    0.0000    0.0039    2.3723
CENTER   138      0.0013    0.7908    0.0013    0.7908    0.0013    0.7908


FAULT CURRENT AT BUS   500 [CENTER   138]:

  500             0.0278   -1.1270    0.0278   -1.1270    0.0278   -1.1270    0.0833   -3.3809
CENTER   138      0.0833   -3.3809    0.0000    0.0000    0.0000    0.0000

POSITIVE SEQUENCE EQUIVALENT FAULT ADMITTANCE    0.0727   -2.4765

ENTER BUS NUMBER: 0
```

Zero sequence fault current = .0278 – j1.1270

Figure 11.41. Dialog to Recalculate L-G Fault at Bus 500 with Simplified System Modeling (Sheet 2 of 2)

Figure 11.40, "Dialog to Recalculate L-G Fault at Bus 500 with Simplified System Modeling (Sheet 1 of 2)" shows the dialog to repeat the previous examples calculation neglecting system loads, shunt paths (except in the zero-sequence), transformer off-nominal ratio, and pre-event conditions. Activity FLAT,CL is used immediately after the dialog shown in Figure 11.37, "Dialog for Example 10.3.4.1 - L-G Fault at Bus 500 (Sheet 1 of 2)" to set all pre-event voltages to (1 + j0) and delete all unwanted modeling detail from the working file. Activity FLAT,CL is followed by activity SEQD to rebuild the matrices needed in calculation; this is necessary whenever a switching or modeling change alters any sequence network model or pre-event voltage profile. Activity SCMU is then run, as in Figure 11.37, "Dialog for Example 10.3.4.1 - L-G Fault at Bus 500 (Sheet 1 of 2)", to apply the L-G fault at bus 500 and calculate its effect.

A comparison of the second page of Figure 11.41, "Dialog to Recalculate L-G Fault at Bus 500 with Simplified System Modeling (Sheet 2 of 2)" with the second page of Figure 11.38, "Dialog for Example 10.3.4.1 - L-G Fault at Bus 500 (Sheet 2 of 2)" shows the effect of the modeling change on the calculated fault current, which is reduced from 3.73 per unit (from Figure 11.37, "Dialog for Example 10.3.4.1 - L-G Fault at Bus 500 (Sheet 1 of 2)") to 3.38 per unit. This reduction is due, principally, to the neglect of nonunity values of generator positive-sequence internal source voltages in the flat system modeling, as covered in the section called "Effect of Pre-Event Conditions on Fault Calculations".

The sum of contributions at bus 500 shows current flowing to ground in the unfaulted b- and c-phases even though all load and shunt capacitor admittances were removed from the system model by activity FLAT. The zero-sequence shunt admittance of the transformer connected at bus 500 remains in the zero-sequence model as a significant path for zero-sequence current. (FLAT,CL removed *all* positive- and negative-sequence shunts and *no* zero-sequence shunts). The significance of the different values of sums-of-contributions and fault current in this example is revealed in Figure 11.42, "Conditions in Load Transformer At Bus 500 Corresponding to Figure 11.34, "Output Formats of Activity SCMU"", a phase-by-phase schematic diagram for conditions at bus 500. From this figure it is immediately apparent that the neutral ground strap of the transformer carries a current of 2.37 per unit. This current is essentially in phase with the fault current and hence would appear to a ground current relay to be flowing from ground toward the fault on bus 500.

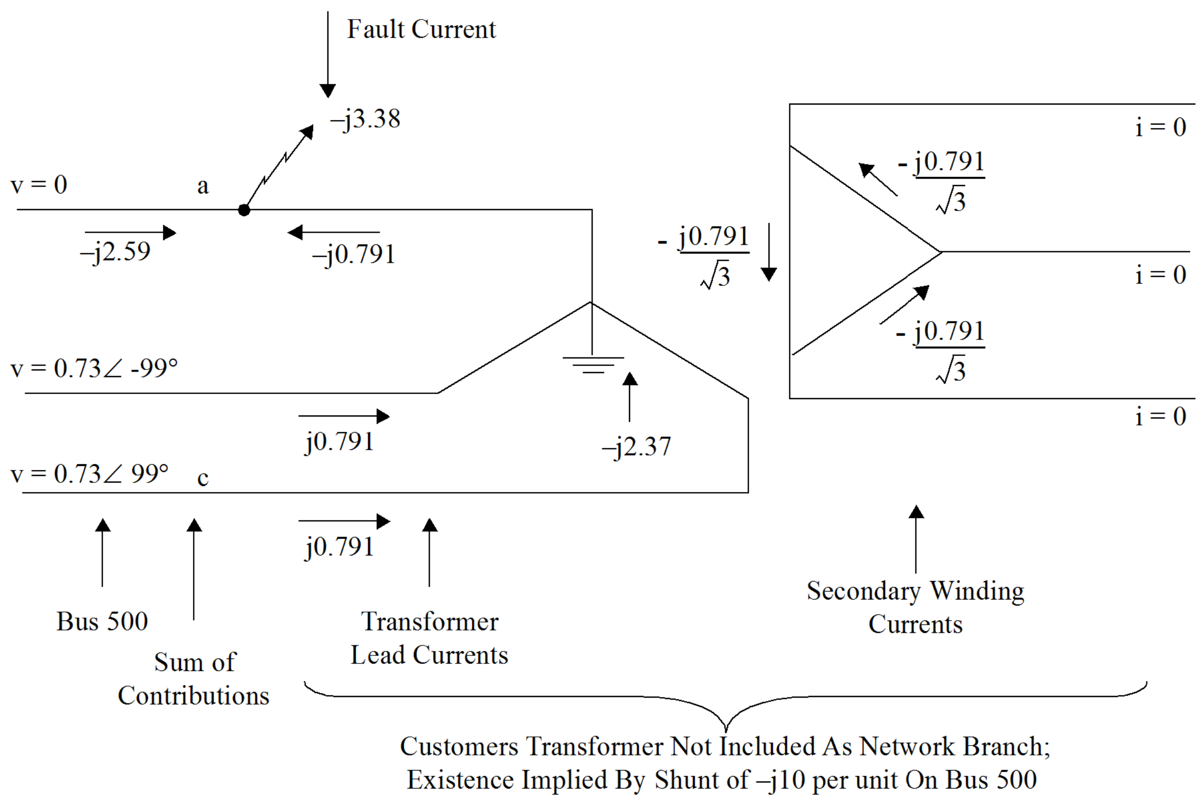

Figure 11.42. Conditions in Load Transformer At Bus 500 Corresponding to Figure 11.34, "Output Formats of Activity SCMU"

Removal of Load Transformer Ground

Figure 11.43, "Dialog to Recalculate L-G Fault at Bus 500 with Ground Removed from Load Transformer at Bus 500 (Sheet 1 of 2)" shows the dialog to extend the previous two examples to find the effect on fault current and transformer neutral voltage if the ground connection of the transformer should be broken. Activity SQCH is used to remove the zero-sequence shunt representing the effect of the transformer on bus 500. This must, again, be followed by SCEQ because the change modifies the zero-sequence network. SCMU is then used, to recalculate the fault.

The results now show identical values for sum of contributions and fault current because the fault is the only path to ground from bus 500. Removal of the path through the transformer ground reduces the L-G fault current from 3.38 per unit to 2.85 per unit because all zero-sequence current must flow to bus 500 through the impedance of transmission lines, rather than through the lower impedance path provided by the transformer.

```
ACTIVITY? sqch

ENTER CHANGE CODE:
 0 = EXIT ACTIVITY              1 = SHUNTS (ZERO & NEG SEQS)
 2 = GENERATOR IMPEDANCES       3 = ZERO SEQ BRANCH DATA
 4 = ZERO SEQ SWITCHED SHUNTS: 1

ENTER BUS NUMBER (0 FOR NEW CHANGE CODE, -1 TO EXIT): 500

DATA FOR BUS   500 [CENTER   138]:
       G(ZERO)     B(ZERO)       G(NEG)      B(NEG)
OLD    0.00000  -10.00000      0.00000     0.00000 CHANGE IT? y
ENTER SHUNTZ, SHUNTN: ,0
NEW    0.00000     0.00000     0.00000     0.00000

ENTER BUS NUMBER (0 FOR NEW CHANGE CODE, -1 TO EXIT): -1

ACTIVITY? flat,cl

ENTER 1 TO SET TAP RATIOS TO UNITY: 1

ENTER 1 TO SET CHARGING TO ZERO: 1

ENTER 1 TO SET SHUNTS TO ZERO IN POSITIVE SEQUENCE
      2 TO SET SHUNTS TO ZERO IN ALL SEQUENCES: 1

ACTIVITY? seqd
DIAGONALS =      6  OFF-DIAGONALS =      8  MAX SIZE =    12
POS. SEQUENCE: DIAGONALS =      6  OFF-DIAGONALS =      8
NEG. SEQUENCE: DIAGONALS =      6  OFF-DIAGONALS =      8
DIAGONALS =      6  OFF-DIAGONALS =     10  MAX SIZE =    20
ZERO SEQ. GEN. IMPEDANCE IGNORED AT BUS   100 [WEST GEN 138] MACH 1--USING XT
ZERO SEQ. GEN. IMPEDANCE IGNORED AT BUS   100 [WEST GEN 138] MACH 2--USING XT
BUS   600 [EAST GEN12.5] ISOLATED IN ZERO SEQUENCE
ZERO SEQUENCE: DIAGONALS =      6  OFF-DIAGONALS =    10

ACTIVITY? scmu

ENTER UNBALANCE CODE:
 0 FOR NO MORE            1 FOR FIRST L-G
 2 FOR SECOND L-G         3 FOR FIRST L-L-G
 4 FOR SECOND L-L-G       5 FOR 1 PHASE CLOSED
 6 FOR 2 PHASES CLOSED    7 FOR THREE PHASE FAULT
 8 FOR ONE END OPENED     9 FOR IN LINE SLIDER: 1

ENTER BUS NUMBER (0 FOR NEW FAULT CODE, -1 FOR NO MORE): 500
ENTER PHASE (1, 2 OR 3): 1
ENTER FAULT IMPEDANCE (R,X): 0 0

ENTER UNBALANCE CODE:
 0 FOR NO MORE            1 FOR FIRST L-G
 2 FOR SECOND L-G         3 FOR FIRST L-L-G
 4 FOR SECOND L-L-G       5 FOR 1 PHASE CLOSED
 6 FOR 2 PHASES CLOSED    7 FOR THREE PHASE FAULT
 8 FOR ONE END OPENED     9 FOR IN LINE SLIDER: 0

UNBALANCES TO BE APPLIED:

LINE TO GROUND FAULT AT BUS   500 [CENTER   138]   PHASE 1
  L-G Z =    0.0000        0.0000

ENTER 1 IF OK, 0 TO RE-SPECIFY UNBALANCES, -1 TO EXIT ACTIVITY: 1
```

Activity SQCH to change sequence network

Select bus-connected shunts

Yes

Enter new value of 0 for imaginary part

That's right!

Re-run SEQD to recognize model changes

As in Figure 11-31 and Figure 11-33

Figure 11.43. Dialog to Recalculate L-G Fault at Bus 500 with Ground Removed from Load Transformer at Bus 500 (Sheet 1 of 2)

```
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UNBALANCES APPLIED:

LINE TO GROUND FAULT AT BUS   500 [CENTER   138]   PHASE 1
  L-G Z =    0.0000       0.0000

              SEQUENCE THEVENIN IMPEDANCES AT FAULTED BUSES:

  BUS   NAME  BSKV          ZERO               POSITIVE             NEGATIVE
  500 CENTER   138     0.02056  0.23342     0.01000  0.48333     0.01000  0.33333

LINE TO GROUND FAULT AT BUS   500 [CENTER   138]:

SEQUENCE     RE(V0)     IM(V0)     RE(V+)     IM(V+)     RE(V-)     IM(V-)    RE(3V0)    IM(3V0)
PHASE        RE(VA)     IM(VA)     RE(VB)     IM(VB)     RE(VC)     IM(VC)   transformer primary

 500  (P.U.) -0.2227     0.0110     0.5400    -0.0082    -0.3173    -0.0027    -0.6681     0.0329
CENTER    138 0.0000     0.0000    -0.3388    -0.7260    -0.3293     0.7590

SEQUENCE     RE(I0)     IM(I0)     RE(I+)     IM(I+)     RE(I-)     IM(I-)    RE(3I0)    IM(3I0)
PHASE        RE(IA)     IM(IA)     RE(IB)     IM(IB)     RE(IC)     IM(IC)

FROM    100 1 0.0147    -0.5154     0.0184    -0.4754     0.0184    -0.4754     0.0441    -1.5461
WEST GEN 138 0.0514    -1.4663    -0.0037    -0.0399    -0.0037    -0.0399

FROM    400 1 0.0220    -0.4355     0.0184    -0.4754     0.0184    -0.4754     0.0661    -1.3065
EAST      138 0.0588    -1.3864     0.0037     0.0399     0.0037     0.0399

SUM OF CONTRIBUTIONS INTO BUS   500 [CENTER   138]:

  500         0.0367    -0.9509     0.0367    -0.9509     0.0367    -0.9509     0.1102    -2.8526
CENTER    138 0.1102    -2.8526     0.0000     0.0000     0.0000     0.0000

CONTRIBUTIONS EQUIVALENT POSITIVE SEQUENCE ADMITTANCE    0.0949   -1.7593
                                                                       Identical – fault is now
                                                                       the only path to
FAULT CURRENT AT BUS   500 [CENTER   138]:                             ground at bus 500

  500         0.0367    -0.9509     0.0367    -0.9509     0.0367    -0.9509     0.1102    -2.8526
CENTER   138  0.1102    -2.8526     0.0000     0.0000     0.0000     0.0000

POSITIVE SEQUENCE EQUIVALENT FAULT ADMITTANCE    0.0949   -1.7593

ENTER BUS NUMBER: 0
```

Figure 11.44. Dialog to Recalculate L-G Fault at Bus 500 with Ground Removed from Load Transformer at Bus 500 (Sheet 2 of 2)

This example illustrates another important consideration in ground faults. The voltages applied to the transformer primary leads at bus 500 are shown in Figure 11.45, "Determination of Neutral Voltage in Ungrounded Wye-Connected Load Transformer". Because this transformer has a delta-connected secondary winding, the three primary *winding* voltages must sum to zero, even though the primary lead-to-ground voltages do not. This results in a neutral-to-ground voltage in the transformer of (–0.223 + j0.011) per unit; an actual voltage of

0.223 × 138 / 1.732 = 17.8 kV

An unbolted or damaged neutral connection is dangerous!

$$v_{bn} - v_{an} = v_b$$

$$v_{bn} - v_{cn} = v_b - v_c \qquad \text{(Primary)}$$

$$v_{cn} - v_{an} = v_c$$

$$v_{an} + v_{bn} + v_{cn} = 0 \qquad \text{(via Secondary)}$$

$$v_{an} = 0.223 - j0.001 = v_n$$

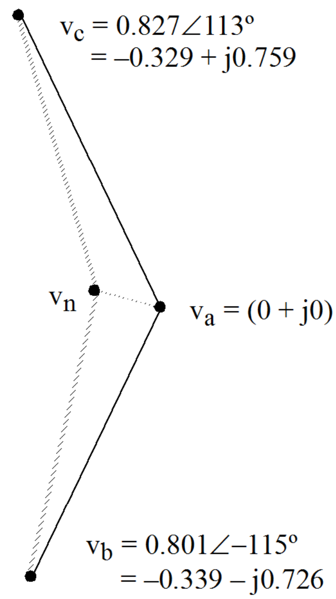

Figure 11.45. Determination of Neutral Voltage in Ungrounded Wye-Connected Load Transformer

Use of Activity SCOP

Figure 11.46, "Use of Full Detail in Calculating Line Fault with One End Open (Sheet 1 of 4)" shows the dialog for an example using activity SCOP to examine results beyond the fault current outputs provided by activity SCMU. In this example, the 33-kV circuit from bus 300 to bus 200 is faulted, line-to-ground, 80% of the distance from bus 300 toward bus 200. The user needs to know the line currents and currents in the 33/138-kV transformer between buses 300 and 400. Use of the line-end fault option of activity SCMU (see Figure 11.28, "Faults and Unbalances Allowed by PSS®E"f) automatically opens the line-end at bus 200 and creates two dummy buses:

99998 at the open end of the branch

99999 at the point of the fault

Figure 11.46, "Use of Full Detail in Calculating Line Fault with One End Open (Sheet 1 of 4)" shows the dialog with SEQD and SCMU to apply the fault. Figure 11.47, "Use of Full Detail in Calculating Line Fault with One End Open (Sheet 2 of 4)" shows the output from activity SCMU. The sum-of-contributions and fault current at bus 99999, the fault point, are equal as expected. The output for bus 300 in Figure 11.47, "Use of Full Detail in Calculating Line Fault with One End Open (Sheet 2 of 4)"b shows the b-phase current in the transformer lead to be (–0.8646 + j0.8481) per unit, which equals 1.211 per unit at 135.6°, while the a-phase and c-phase lead currents are about 0.2 per unit, feeding the load at bus 300.

Figure 11.48, "Use of Full Detail in Calculating Line Fault with One End Open (Sheet 3 of 4)" shows the use of SCOP to examine system conditions further, as needed to build the detailed picture shown in Figure 11.50, "Results Indicated by Figure 11.46, "Use of Full Detail in Calculating Line Fault with One End Open (Sheet

1 of 4)" (Phase Currents in Rectangular Coordinates)". The current output for bus 400 shows a lead current of about 0.7 per unit in phases a and b; while only the b-phase lead on the bus 300 side carries a major fault current. The current of 0.7 per unit is roughly (1/1.732) times the b-phase current on the other side of the transformer, corresponding to the inherent √ 3-to-1 turns ratio of the phase windings of the delta-wye transformer. (If no load had been present on bus 300, the ratio of currents would have been exactly 1 to 1.732.) Figure 11.49, "Use of Full Detail in Calculating Line Fault with One End Open (Sheet 4 of 4)" shows the further use of activity SCOP to show apparent impedances looking outward from buses 300 and 400.

The apparent impedance looking toward the fault from bus 300 in the b-phase is (0.1160 + j0.5625) per unit or 0.5718 at 79.6°. Figure 11.25, "Augmentation of Established Power Flow Case to Include Negative- and Zero-Sequence Networks (Sheet 1 of 2)" shows that the line has

$Z^+ = 0.1 + j0.55 = Z_p - Z_m$

$Z^0 = 0.2 + j1.11 = Z_p + 2Z_m$

and, therefore, the phase self-impedance is $(2Z^+ + Z^o)/3 = (0.133 + j0.737)$. The apparent impedance looking toward the fault might be expected to be $0.8 \times (0.133 + j0.737) = (0.106 + j0.589)$. The discrepancy between this value and the value shown by SCOP is due to the mutual coupling between the 200-300 circuit and the 138-kV circuits 100-500 and 500-400. A sharp difference is noticed between the apparent impedances looking toward the fault from bus 300 and bus 400.

```
ACTIVITY? case ufsqa                                 Pick up fully detailed system model

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CASE ufsqa.sav WAS SAVED ON THU OCT 07, 1993  10:29

ACTIVITY? solv                                       Check that system is solved

ITER DELTAV/TOL   BUS    REAL(DELTAV)    IMAG(DELTAV)
   1     0.560    600    -0.4988E-04     -0.2546E-04

REACHED TOLERANCE IN   1 ITERATIONS

LARGEST MISMATCH:     0.00 MW     0.03 MVAR      0.03 MVA-BUS   500 [CENTER   138]
SYSTEM TOTAL ABSOLUTE MISMATCH:                  0.09 MVA

ACTIVITY? seqd                                       SEQD to prepare solution matrices
DIAGONALS =       6   OFF-DIAGONALS =       8   MAX SIZE =     12
POS. SEQUENCE: DIAGONALS =       6  OFF-DIAGONALS =       8
NEG. SEQUENCE: DIAGONALS =       6  OFF-DIAGONALS =       8
DIAGONALS =       6   OFF-DIAGONALS =      10   MAX SIZE =     20
ZERO SEQ. GEN. IMPEDANCE IGNORED AT BUS    100 [WEST GEN 138] MACH 1--USING XT
ZERO SEQ. GEN. IMPEDANCE IGNORED AT BUS    100 [WEST GEN 138] MACH 2--USING XT
BUS    600 [EAST GEN12.5] ISOLATED IN ZERO SEQUENCE
ZERO SEQUENCE: DIAGONALS =       6  OFF-DIAGONALS =      10

ACTIVITY? scmu                                       SCMU to apply and solve for unbalance

ENTER UNBALANCE CODE:
 0 FOR NO MORE             1 FOR FIRST L-G
 2 FOR SECOND L-G          3 FOR FIRST L-L-G
 4 FOR SECOND L-L-G        5 FOR 1 PHASE CLOSED
 6 FOR 2 PHASES CLOSED     7 FOR THREE PHASE FAULT
 8 FOR ONE END OPENED      9 FOR IN LINE SLIDER: 8           Section line-end fault

ENTER FROM BUS, TO BUS, CIRCUIT IDENTIFIER                   Fault online 200-300
 (FROM BUS = 0 FOR NEW FAULT CODE, -1 FOR NO MORE): 200 300
ENTER 1 IF BUS    200 [WEST     33.0] IS OPENED END: 1       200 end is open
ENTER A FACTOR AS THE DISTANCE FROM BUS    300 [EAST     33.0]: .8    Fault 80% of way down line
ENTER 1 FOR L-G, 2 FOR L-L-G, 3 FOR 3 PHASE FAULT: 1         Fault is L-G
ENTER PHASE (1, 2 OR 3): 2                                   On Phase 2
ENTER FAULT IMPEDANCE (R,X): 0. 0.                           Zero fault impedance

ENTER UNBALANCE CODE:
 0 FOR NO MORE             1 FOR FIRST L-G
 2 FOR SECOND L-G          3 FOR FIRST L-L-G
 4 FOR SECOND L-L-G        5 FOR 1 PHASE CLOSED
 6 FOR 2 PHASES CLOSED     7 FOR THREE PHASE FAULT
 8 FOR ONE END OPENED      9 FOR IN LINE SLIDER: 0           No simultaneous fault

UNBALANCES TO BE APPLIED:

LINE TO GROUND FAULT AT BUS 99999 [DUMMYBUS33.0]    PHASE 2
  L-G Z =    0.0000       0.0000
  DUMMY BUS IS  80.0% FROM BUS    300 [EAST     33.0] TO BUS    200 [WEST     33.0]
  BUS    200 [WEST     33.0] END IS OPEN

ENTER 1 IF OK, 0 TO RE-SPECIFY UNBALANCES, -1 TO EXIT ACTIVITY: 1     That's right!

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UNBALANCES APPLIED:

LINE TO GROUND FAULT AT BUS 99999 [DUMMYBUS33.0]    PHASE 2
  L-G Z =    0.0000       0.0000
  DUMMY BUS IS  80.0% FROM BUS    300 [EAST     33.0] TO BUS    200 [WEST     33.0]
  BUS    200 [WEST     33.0] END IS OPEN
ZERO SEQUENCE: DIAGONALS =      8  OFF-DIAGONALS =     15
NEG. SEQUENCE: DIAGONALS =      8  OFF-DIAGONALS =      7
POS. SEQUENCE: DIAGONALS =      8  OFF-DIAGONALS =      7
```

a. Fault Application

Figure 11.46. Use of Full Detail in Calculating Line Fault with One End Open (Sheet 1 of 4)

```
              SEQUENCE THEVENIN IMPEDANCES AT FAULTED BUSES:

   BUS    NAME  BSKV          ZERO                POSITIVE             NEGATIVE
 99999 DUMMYBUS33.0    0.55213  1.68821     0.25973  0.98729     0.18188  0.89523

 LINE TO GROUND FAULT AT BUS 99999 [DUMMYBUS33.0]:     Phase voltage at point of fault

 SEQUENCE      RE(V0)    IM(V0)    RE(V+)    IM(V+)    RE(V-)    IM(V-)   RE(3V0)   IM(3V0)
 PHASE         RE(VA)    IM(VA)    RE(VB)    IM(VB)    RE(VC)    IM(VC)

 99999 (P.U.) 0.4338    0.2128    0.6221   -0.3830    0.0119   -0.2482    1.3013    0.6383
 DUMMYBUS33.0 1.0678   -0.4184    0.0000    0.0000    0.2335    1.0568

 SEQUENCE      RE(I0)    IM(I0)    RE(I+)    IM(I+)    RE(I-)    IM(I-)   RE(3I0)   IM(3I0)
 PHASE         RE(IA)    IM(IA)    RE(IB)    IM(IB)    RE(IC)    IM(IC)

 FROM   300 1 -0.2997    0.4283   -0.0737   -0.2615    0.2638    0.0669   -0.8992    1.2850
 EAST    33.0 -0.1096    0.2338   -0.6792    0.8179   -0.1104    0.2334

 FROM 99998 1 0.1099    -0.2335   -0.0002   -0.0003   -0.0001    0.0000    0.3298   -0.7004
 STUB END33.0 0.1096    -0.2338    0.1098   -0.2333    0.1104   -0.2334


 SUM OF CONTRIBUTIONS INTO BUS 99999 [DUMMYBUS33.0]:

 99999        -0.1898    0.1949   -0.0739   -0.2618    0.2637    0.0669   -0.5693    0.5846
 DUMMYBUS33.0 0.0000     0.0000   -0.5693    0.5846    0.0000    0.0000

 CONTRIBUTIONS EQUIVALENT POSITIVE SEQUENCE ADMITTANCE    0.1018   -0.3582        Fault current


 FAULT CURRENT AT BUS 99999 [DUMMYBUS33.0]:

 99999        -0.1898    0.1949   -0.0739   -0.2618    0.2637    0.0669   -0.5693    0.5846
 DUMMYBUS33.0 0.0000     0.0000   -0.5693    0.5846    0.0000    0.0000
                                                                               Current at
 POSITIVE SEQUENCE EQUIVALENT FAULT ADMITTANCE    0.1018   -0.3582             bus 300 side
                                                                               of 300-400
 ENTER BUS NUMBER: 300                                                         transformer

 SEQUENCE      RE(V0)    IM(V0)    RE(V+)    IM(V+)    RE(V-)    IM(V-)   RE(3V0)   IM(3V0)
 PHASE         RE(VA)    IM(VA)    RE(VB)    IM(VB)    RE(VC)    IM(VC)

   300 (P.U.) 0.0733    0.0513    0.7312   -0.4364    0.0036   -0.1268    0.2198    0.1538
 EAST     33.0 0.8081   -0.5119   -0.5622   -0.2973   -0.0260    0.9630

 SEQUENCE      RE(I0)    IM(I0)    RE(I+)    IM(I+)    RE(I-)    IM(I-)   RE(3I0)   IM(3I0)
 PHASE         RE(IA)    IM(IA)    RE(IB)    IM(IB)    RE(IC)    IM(IC)

 FROM   400 1 -0.3254    0.4650    0.0279   -0.4196    0.2520    0.0415   -0.9761    1.3950
 EAST     138 -0.0454    0.0869   -0.8646    0.8481   -0.0660    0.4599

 FROM 99999 1 0.3254    -0.4650    0.0735    0.2611   -0.2638   -0.0669    0.9761   -1.3950
 DUMMYBUS33.0 0.1350    -0.2708    0.7046   -0.8542    0.1365   -0.2700
                                                        Phase current arriving at
 SUM OF CONTRIBUTIONS INTO BUS   300 [EAST    33.0]:    bus 300 from fault

   300         0.0000    0.0000    0.1014   -0.1585   -0.0118   -0.0254    0.0000    0.0000
 EAST     33.0 0.0896   -0.1839   -0.1600   -0.0061    0.0704    0.1899                Load
                                                                                     currents
 SHUNT + LOAD CURRENT AT BUS   300 [EAST    33.0]:                                   at bus 300

   300         0.0000    0.0000    0.1014   -0.1585   -0.0118   -0.0254    0.0000    0.0000
 EAST     33.0 0.0896   -0.1839   -0.1600   -0.0061    0.0704    0.1899

 ENTER BUS NUMBER: 0
```

b. Fault Current Output from SCMU

Figure 11.47. Use of Full Detail in Calculating Line Fault with One End Open (Sheet 2 of 4)

```
ACTIVITY? scop                                    SCOP for more complete output

ENTER OUTPUT DEVICE CODE:
 0 FOR NO OUTPUT         1 FOR CRT TERMINAL
 2 FOR A FILE            3 FOR QMS PS2000
 4 FOR QMS_PS800         5 FOR HARD COPY TERMINAL
 6 FOR ALTERNATE SPOOL DEVICE: 1                  Right here please

 ENTER BRANCH QUANTITY DESIRED:
  0 TO EXIT ACTIVITY            1 FOR CURRENTS
  2 FOR APPARENT IMPEDANCES     3 FOR APPARENT ADMITTANCES: 1     Select current output
 ENTER UP TO 20 BUS NUMBERS
400                                                Look at bus 400

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 UNBALANCED FAULT ANALYSIS EXAMPLE                                    CURRENTS

 LINE TO GROUND FAULT AT BUS 99999 [DUMMYBUS33.0]    PHASE 2
   L-G Z =    0.0000         0.0000
   DUMMY BUS IS  80.0% FROM BUS    300 [EAST    33.0] TO BUS   200 [WEST    33.0]
   BUS   200 [WEST     33.0] END IS OPEN                       Voltages at bus 400

SEQUENCE      RE(V0)    IM(V0)    RE(V+)    IM(V+)    RE(V-)    IM(V-)   RE(3V0)   IM(3V0)
PHASE         RE(VA)    IM(VA)    RE(VB)    IM(VB)    RE(VC)    IM(VC)

   400(P.U.) -0.0123   -0.0090    0.8844    0.0240   -0.0450   -0.0721   -0.0368   -0.0271
 EAST    138  0.8272   -0.0572   -0.3488   -0.7898   -0.5152    0.8199

 SEQUENCE     RE(I0)    IM(I0)    RE(I+)    IM(I+)    RE(I-)    IM(I-)   RE(3I0)   IM(3I0)
 PHASE        RE(IA)    IM(IA)    RE(IB)    IM(IB)    RE(IC)    IM(IC)

 TO    300  1  0.0000    0.0000    0.2398   -0.3581    0.2450   -0.0923    0.0000    0.0000
 EAST  33.0    0.4848   -0.4505   -0.4726    0.2297   -0.0122    0.2207

 TO    500  1  0.0430   -0.0584    0.2413    0.1336   -0.1238    0.0168    0.1290   -0.1753
 CENTER    138 0.1605    0.0920    0.0854   -0.4499   -0.1169    0.1826
      PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS®E      WED JAN 19, 1994  16:31
 PSS®E APPLICATION GUIDE                                                BRANCH
 UNBALANCED FAULT ANALYSIS EXAMPLE                                    CURRENTS

 TO    600  1 -0.0430    0.0584   -0.4811    0.2245   -0.1212    0.0755   -0.1290    0.1753
EAST GEN12.5 -0.6452    0.3584    0.3872    0.2201    0.1291   -0.4033

 SUM OF        0.0000    0.0000    0.0000    0.0000    0.0000    0.0000    0.0000    0.0000
CONTRIBUTIONS 0.0000    0.0000    0.0000    0.0000    0.0000    0.0000
 ENTER UP TO 20 BUS NUMBERS                                Currents at bus 400 side of
600                             Now select bus 600         300–400 transformer

      PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS®E      WED JAN 19, 1994  16:31
 PSS®E APPLICATION GUIDE                                                BRANCH
 UNBALANCED FAULT ANALYSIS EXAMPLE                                    CURRENTS

 SEQUENCE     RE(V0)    IM(V0)    RE(V+)    IM(V+)    RE(V-)    IM(V-)   RE(3V0)   IM(3V0)
 PHASE        RE(VA)    IM(VA)    RE(VB)    IM(VB)    RE(VC)    IM(VC)

  600 (P.U.)   0.0000    0.0000    0.7261    0.5601   -0.0473   -0.0252    0.0000    0.0000
 EAST GEN12.5 0.6787    0.5348    0.1675   -0.9372   -0.8463    0.4024   Voltages at bus 600

 SEQUENCE     RE(I0)    IM(I0)    RE(I+)    IM(I+)    RE(I-)    IM(I-)   RE(3I0)   IM(3I0)
 PHASE        RE(IA)    IM(IA)    RE(IB)    IM(IB)    RE(IC)    IM(IC)

 MACHINE 1     0.0000    0.0000   -0.5421   -0.0473   -0.0688    0.1291    0.0000    0.0000
              -0.6110    0.0819    0.1527    0.3689    0.4582   -0.4508

 TO    400  1  0.0000    0.0000    0.5421    0.0473    0.0688   -0.1291    0.0000    0.0000
 EAST      138 0.6110   -0.0819   -0.1527   -0.3689   -0.4582    0.4508

 SUM OF        0.0000    0.0000    0.0000    0.0000    0.0000    0.0000    0.0000    0.0000
CONTRIBUTIONS 0.0000    0.0000    0.0000    0.0000    0.0000    0.0000
 ENTER UP TO 20 BUS NUMBERS
0                                                 End of current output
```

c. Output of Currents From SCOP

Figure 11.48. Use of Full Detail in Calculating Line Fault with One End Open (Sheet 3 of 4)

```
ENTER BRANCH QUANTITY DESIRED:
0 TO EXIT ACTIVITY           1 FOR CURRENTS
2 FOR APPARENT IMPEDANCES    3 FOR APPARENT ADMITTANCES: 2
ENTER UP TO 20 BUS NUMBERS
300 400

PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS®E      WED JAN 19, 1994  16:31
PSS®E APPLICATION GUIDE                                                 APPARENT
UNBALANCED FAULT ANALYSIS EXAMPLE                                     IMPEDANCES

SEQUENCE           RE(V0)    IM(V0)    RE(V+)    IM(V+)    RE(V-)    IM(V-)   RE(3V0)    IM(3V0)
PHASE              RE(VA)    IM(VA)    RE(VB)    IM(VB)    RE(VC)    IM(VC)

 300   (P.U.)      0.0733    0.0513    0.7312   -0.4364    0.0036   -0.1268    0.2198     0.1538
EAST     33.0      0.8081   -0.5119   -0.5622   -0.2973   -0.0260    0.9630

SEQUENCE           RE(Z0)    IM(Z0)    RE(Z+)    IM(Z+)    RE(Z-)    IM(Z-)
PHASE              RE(ZA)    IM(ZA)    RE(ZB)    IM(ZB)    RE(ZC)    IM(ZC)

TO    400  1       0.0000    0.1576   -1.1508   -1.6663    0.0667    0.4921
EAST      138      8.4408    4.8840   -0.1595   -0.5003   -2.0596    0.2391

TO 99999  1        0.0000   -0.1576    0.8184    3.0308   -0.1017   -0.4547
DUMMYBUS33.0      -2.7056   -1.6355    0.1160    0.5625    2.8800   -1.3594

PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS®E      WED JAN 19, 1994  16:31
PSS®E APPLICATION GUIDE                                                 APPARENT
UNBALANCED FAULT ANALYSIS EXAMPLE                                     IMPEDANCES

SEQUENCE           RE(V0)    IM(V0)    RE(V+)    IM(V+)    RE(V-)    IM(V-)   RE(3V0)    IM(3V0)
PHASE              RE(VA)    IM(VA)    RE(VB)    IM(VB)    RE(VC)    IM(VC)

 400   (P.U.)     -0.0123   -0.0090    0.8844    0.0240   -0.0450   -0.0721   -0.0368    -0.0271
EAST      138      0.8272   -0.0572   -0.3488   -0.7898   -0.5152    0.8199

SEQUENCE           RE(Z0)    IM(Z0)    RE(Z+)    IM(Z+)    RE(Z-)    IM(Z-)
PHASE              RE(ZA)    IM(ZA)    RE(ZB)    IM(ZB)    RE(ZC)    IM(ZC)

TO    300  1       0.0000 9999.0000    1.0954    1.7360   -0.0635   -0.3183
EAST     33.0      0.9745    0.7875   -0.0602    1.6419    3.8318    2.1229

TO    500  1       0.0000   -0.2101    2.8470   -1.4771    0.2788    0.6203
CENTER    138      3.7254   -2.4925    1.5524   -1.0700    4.4660   -0.0376

TO    600  1       0.0000    0.2101   -1.4904   -0.7454    0.0000    0.5954
EAST GEN12.5      -1.0173   -0.4765   -1.5572   -1.1545   -2.2149   -0.5686
ENTER UP TO 20 BUS NUMBERS
0

ENTER BRANCH QUANTITY DESIRED:
0 TO EXIT ACTIVITY           1 FOR CURRENTS
2 FOR APPARENT IMPEDANCES    3 FOR APPARENT ADMITTANCES: 0

ACTIVITY?
```

Select apparent impedance output

Voltage bus at 300

Apparent impedance looking from 300 toward fault

Apparent impedance looking from 400 through transformer and toward fault

d. Output of Apparent Impedances from SCOP

Figure 11.49. Use of Full Detail in Calculating Line Fault with One End Open (Sheet 4 of 4)

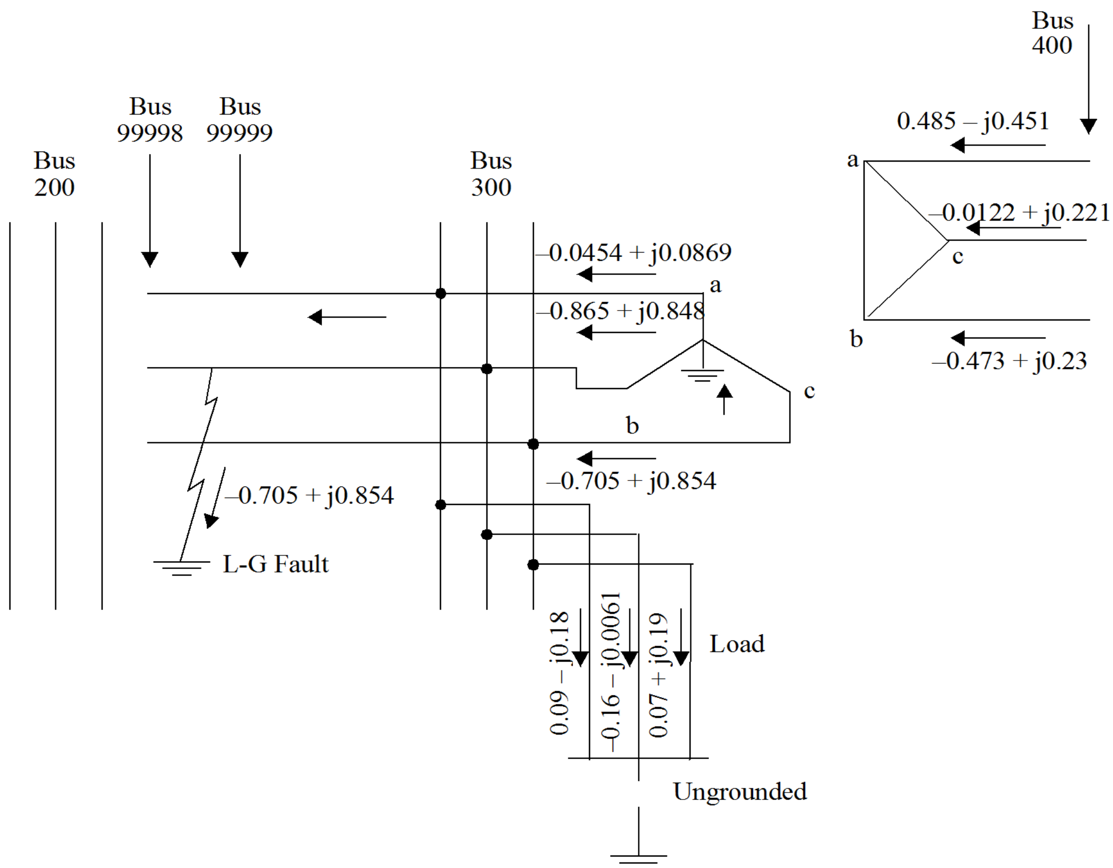


Figure 11.50. Results Indicated by Figure 11.46, "Use of Full Detail in Calculating Line Fault with One End Open (Sheet 1 of 4)" (Phase Currents in Rectangular Coordinates)

11.4. Scanning Short Circuit Analysis

11.4.1. General Points

The scanning short circuit analysis run by activity ASCC compliments activity SCMU by providing automatic coverage of standard events at all buses in a segment of the system rather than detailed and flexible analysis of a specific event. ASCC can handle only line-to-ground and three-phase short circuit events, but it is able automatically to show the effect of these two events on a bus when the immediate surrounding transmission is in a variety of conditions. Activity ASCC is intended primarily for batch operation in which the subsystem to be covered is preselected in an opening dialog and its report formats are designed for printing via a bulk output unit.

ASCC can be applied to the same power system model (i.e., the same saved case) as activity SCMU. It is able to use the same full level of detail as SCMU, but much of its application will be to system models where refinements such as recognition of load current, phase shift, and off-nominal transformer tap position are unnecessary. Unlike activity SCMU, which requires external use of activity FLAT,CL to reduce the level of detail of the working case, activity ASCC can be instructed to ignore all but the most basic system modeling without requiring the use of FLAT,CL to modify the working case.

11.4.2. Activity ASCC

Terminology

Buses are identified in relation to a given home bus. A home bus may be designated by the user or chosen by ASCC. After the home bus has been chosen, all other buses in the system are said to be 1, 2, or m levels away. The buses of greatest interest, with respect to a given home bus, are usually those 1 or 2 levels away, as shown in Figure 11.51, "Bus and Branch Contribution Reference for Activity ASCC".

Current *contributions* arriving at the home bus and at buses m levels away from the home bus are measured in each branch at the arriving end as shown in Figure 11.51, "Bus and Branch Contribution Reference for Activity ASCC". In the case of transmission lines, the current at the other end of the branch differs from this contribution only by charging and shunt reactor (or capacitor) current. In the case of transformers, the per-unit current at the other side differs from this contribution (per unit) by the per-unit turns ratio, but the ampere current at the other side differs from the contribution (in amperes) by the transformer's actual turns ratio.

When charging capacitance and line-connected shunt devices are included in the system model, the current contributions are measured at the bus-side of all line connected devices as shown by I_i and I_j in Figure 6-1. That is, currents are measured at the same place in short circuit work as flows are measured in power flow output activities.

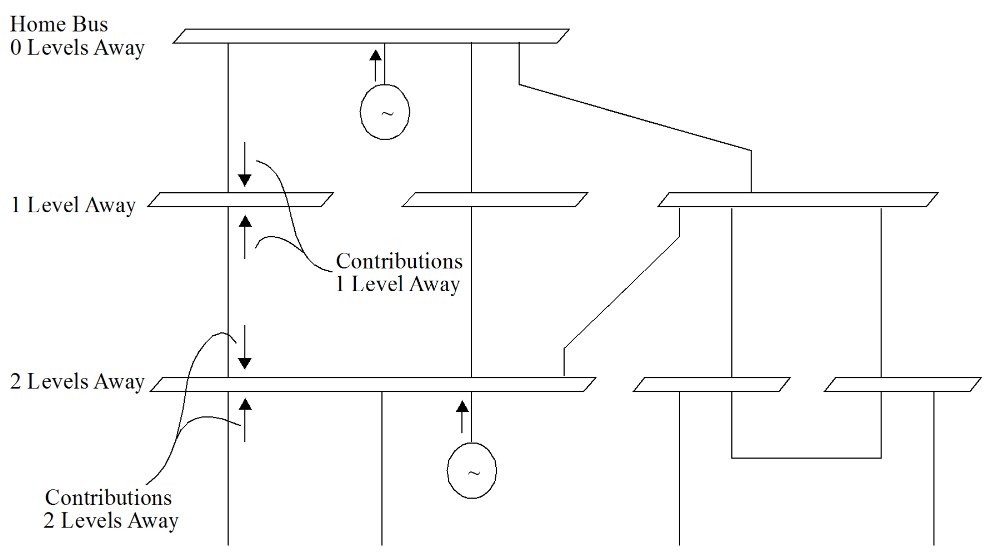


Figure 11.51. Bus and Branch Contribution Reference for Activity ASCC

Faults at a Home Bus

Selection of a home bus initiates the calculation of fault current and branch current contributions for a set of fault conditions related to the home bus as shown in Figure 11.52, "Application of Faults at a Given Home Bus by Activity ASCC". This set includes:

- Faults at the home bus with all incoming branches in service.
- Faults at the bus with each incoming branch out-of-service in turn.
- Faults at the far end of each incoming branch in turn with the far-end circuit breaker open in each case.

If a branch is out-of-service in the working case prior to initiation of ASCC, it is ignored by ASCC and is not considered in the above sequence of line-out and line-end faults.

The calculation of the line-out and line-end currents is intended to allow the determination of the highest circuit breaker duty in the substation. Making this determination requires details of the circuit breaker and bus-section arrangements of the substation, and is usually handled by an independent program. Activity ASCC writes a file containing the subset of its results required by such programs.

Sequenced Home Bus Selection

If invoked without suffix, ASCC invites the user to specify a list of home buses and then handles them in the specified sequence. ASCC calculates and reports on all faults at one home bus before proceeding to the next. If invoked with the suffix, OPT, activity ASCC sequences the home bus through all buses in a subsystem specified in the standard manner as covered in Section 6.6.1 Report Selection and Routing. Again, ASCC calculates all faults related to each home bus before proceeding to the next one in the specified subsystem.

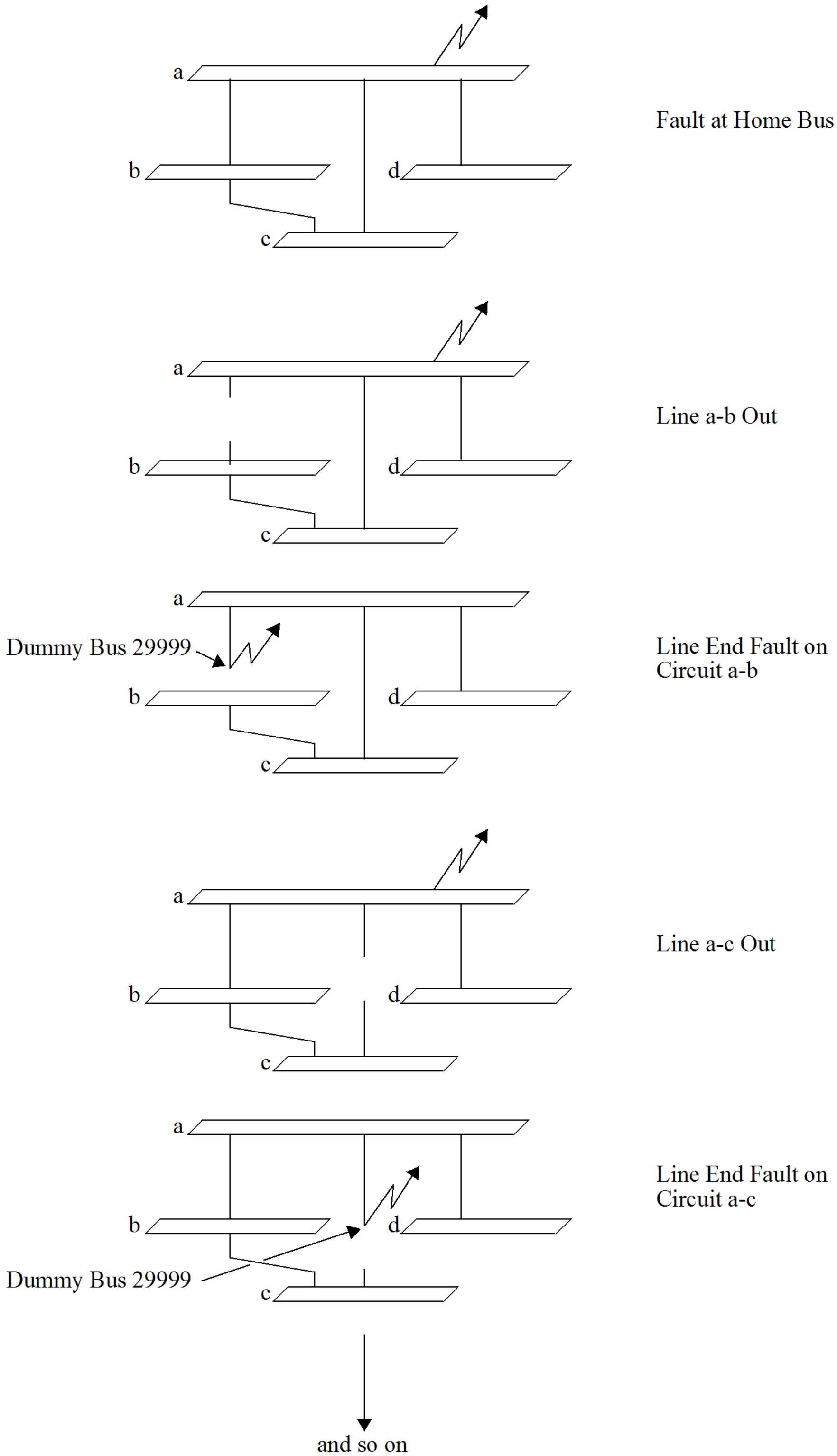


Figure 11.52. Application of Faults at a Given Home Bus by Activity ASCC

Size of Scanned Subsystem

Activity ASCC is intended for use in work where flexibility of user interaction is secondary to production of results in volume. It anticipates that the majority of its output will be routed to a hardcopy device, either directly or through a named output file. Accordingly, the dialog of ASCC encourages the user to state the requirements and then leave it alone while it runs a more or less extensive set of cases without further instruction. After asking whether to use detailed or classical (FLAT version) calculation, ASCC invites the user to specify the events to be calculated and the amount of monitoring required.

The contributions to each fault may be measured up to *n* levels away from the home bus as defined in Figure 11.51, "Bus and Branch Contribution Reference for Activity ASCC". It is recommended that contributions be reported only zero levels away in the majority of ASCC applications.

Figure 11.53, "Dialog to Apply Activity ASCC to System Shown in Figure 11.15, "Sample System for Fault Analysis"" shows a typical dialog applying ASCC to check fault duty at buses 200 and 300. Representative pages of the output from this run are shown in Figure 11.54, "Output from ASCC from Dialog in Figure 11.53, "Dialog to Apply Activity ASCC to System Shown in Figure 11.15, "Sample System for Fault Analysis"" (Sheet 1 of 3)", Figure 11.57, "Abbreviated Output Format of ASCC when only Three-Phase Fault is Calculated", and Figure 11.58, "Fault Summary File #BDF1 (Breaker Duty File)(Corresponds to Figure 11.53, "Dialog to Apply Activity ASCC to System Shown in Figure 11.15, "Sample System for Fault Analysis"" and Figure 11.54, "Output from ASCC from Dialog in Figure 11.53, "Dialog to Apply Activity ASCC to System Shown in Figure 11.15, "Sample System for Fault Analysis"" (Sheet 1 of 3)")". Even this seemingly minimal run of ASCC produced 19 pages of output, most of this volume is due to the selection of output of conditions *one bus away* from the home bus. This output was generated choosing the full output option of ASCC. Abbreviated output options are available. It is recommended that ASCC be applied to carefully specified subsystems of only a few buses at a time. Application of ASCC to larger systems in single executions is likely to be of greater benefit to the user's paper supplier than to the user.

Activity ASCC does allow an optional data input file through which individual buses may be exempted from being faulted and/or from being reported for remote faults. Dummy buses for three-winding transformers or those used for multisection lines are usually listed here.

11.4.3. Setup for Activity ASCC

Activity ASCC uses exactly the same system model as the detailed fault analysis activity SCMU. All of the modeling practices covered in Section 8.3, "Boundaries and Boundary Buses " are applicable to ASCC. Activity ASCC handles the setup of generator internal sources automatically to correspond to conditions at instant t^-, just before application of the disturbing event; therefore, activity SEQD is not required before the execution of ASCC. Furthermore, CONG or CONG,SQ *should not* be used before ASCC.

Activity ASCC allows the user to choose between the system representation as set up in the working case or a fully simplified classical representation. Choosing the classical or FLAT option in ASCC causes the calculations to assume that all bus voltages are $(1 + j0)$ at instant t^-, and to ignore the following:

- All bus voltage phase differences.
- Off-nominal ratio and phase shift of all transformers.
- All shunt loads and other paths to ground except for generator internal impedances, transformer grounding paths, and shunt loads in the zero-sequence.

```
ACTIVITY? CASE UFSQA                         Retrieve case as set up for general fault analysis
PSSE APPLICATION GUIDE
UNBALANCED FAULT ANALYSIS EXAMPLE

CASE UFSQA.SAV WAS SAVED ON FRI, OCT 11 1991  13:43

ACTIVITY? ASCC                               ASCC for repetitive fault anal-

ENTER :
[1 FOR] , [ 1  FOR ] , [ 1  FOR ] , [1 FOR FLAT] , [1 FOR DOUBLE]
[L - G]   [LINE OUT]   [LINE END]   [CONDITIONS]   [ PRECISION  ]
1 1 1 1                                      Select program options

ENTER OUTPUT OPTION CODE:
 1 = FULL OUTPUT AT HOME BUS AND 'N' LEVELS AWAY
 2 = FULL OUTPUT AT HOME BUS, SUMMARY 'N' LEVELS AWAY
 3 = FAULT CURRENT SUMMARY TABLE: 1

ENTER NUMBER OF LEVELS BACK FOR CONTRIBUTIONS OUTPUT
 (0 FOR OUTPUT AT HOME BUS ONLY): 1

ENTER FILENAME FOR RELAY OUTPUT: BDF1         Record fault duty results in file BDF1

ENTER BRANCH QUANTITY OUTPUT CODE FOR LINE TO GROUND FAULTS
 (0 FOR A PHASE, 1 FOR 3*I0, 2 FOR BOTH): 0
DIAGONALS =      7  OFF-DIAGONALS =      8  MAX SIZE =    12
BUS 99999 [DUMMYBUS     ] ISOLATED IN POS. SEQUENCE
POS. SEQUENCE: DIAGONALS =      7  OFF-DIAGONALS =      8
BUS 99999 [DUMMYBUS     ] ISOLATED IN NEG. SEQUENCE                       Routine
NEG. SEQUENCE: DIAGONALS =      7  OFF-DIAGONALS =      8                 mes-
DIAGONALS =      7  OFF-DIAGONALS =     10  MAX SIZE =    20              sages
ZERO SEQ. GEN. IMPEDANCE IGNORED AT BUS    100 [WEST GEN 138] MACH 1--USING XT   from
ZERO SEQ. GEN. IMPEDANCE IGNORED AT BUS    100 [WEST GEN 138] MACH 2--USING XT
BUS   600 [EAST GEN12.5] ISOLATED IN ZERO SEQUENCE
BUS 99999 [DUMMYBUS     ] ISOLATED IN ZERO SEQUENCE
ZERO SEQUENCE: DIAGONALS =      7  OFF-DIAGONALS =     10

ENTER FAULT CONTROL INPUT FILE NAME:          No file (all buses print and count)

ENTER UP TO 20 BUS NUMBERS
200 300                                       Apply faults to subsystem consisting of buses 200 and 300
```

Figure 11.53. Dialog to Apply Activity ASCC to System Shown in Figure 11.15, “Sample System for Fault Analysis”

Application of any PSS®E solution method to a given system model at a given level of detail will produce the same solution for bus voltages and, to the extent that the different output activities make them available, the same fault current and branch flow results. Hence, the activity sequences shown in Table 11.4, “Equivalence Of Fault Analysis Procedures” would produce the same results when applied to a given pre-event saved case.

It is advantageous to invoke the FLAT option of ASCC whenever classical short circuit calculation is desired, even when the working case has already been established in the classical condition by setup or by activity FLAT,CL. This is because ASCC uses its fast calculation algorithm only when its activity FLAT option has been invoked.

Choosing the FLAT option of ASCC *does not* cause modification of the working case; it only instructs ASCC to ignore data in the working case. Hence, use of SQLI and LIST after ASCC with its FLAT option does not reflect the level of system representation that was used by ASCC. The system representation used by ASCC with its FLAT option can be listed for documentation purposes by using activity FLAT,CL (which *does* modify the working case) and instructing it to adopt classical assumptions for bus voltages, shunts, and transformer ratios.

Table 11.4. Equivalence Of Fault Analysis Procedures

	Power Flow	Detailed Fault Analysis	Activity **ASCC**
Fully Detailed System Model	CASE SOLV CONG,SQ CONL,ALL (100% const. G,B) CHNG (Fault on bus) ORDR FACT TYSL POUT	CASE SOLV SEQD SCMU (3ø or 1ø fault on bus)	CASE SOLV **ASCC** (Do not select FLAT option)
Fully Simplified System Model	CASE FLAT,CL 1 Suppress all detail 1 Suppress all detail 1 Suppress all detail CONG,SQ CHNG (Fault on bus) ORDR FACT TYSL POUT	CASE FLAT,CL 1 Suppress all detail 1 Suppress all detail 1 Suppress all detail SEQD SCMU (3ø or 1ø fault)	CASE **ASCC** (Select FLAT option)

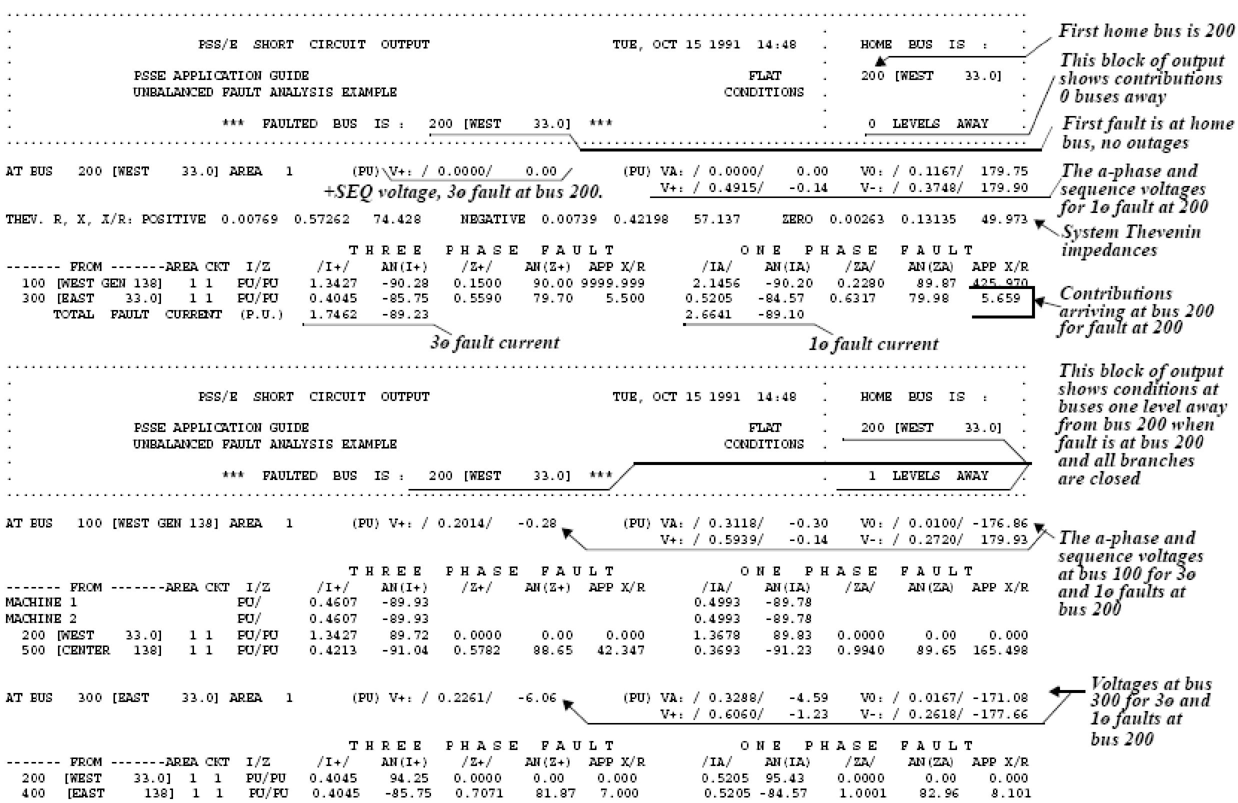
When its FLAT option is not invoked, ASCC uses the full detail present in the working case and gives the same results as the application of activity SCMU in each faulted system.

11.4.4. ASCC Output Formats

Main Outputs

Activity ASCC allows the user to select from three outputs depending on the information and amount of information desired.

Figure 11.54, "Output from ASCC from Dialog in Figure 11.53, "Dialog to Apply Activity ASCC to System Shown in Figure 11.15, "Sample System for Fault Analysis"" (Sheet 1 of 3)" shows sample pages of the most comprehensive output from ASCC. This output is intended for printing on a 132-column batch output device. Each page has a heading box stating its contents in detail. A page of this report contains either conditions at the home bus, or conditions at several buses, all a given level away from the home bus. The meaning of all printed fields is defined in Figure 11.54, "Output from ASCC from Dialog in Figure 11.53, "Dialog to Apply Activity ASCC to System Shown in Figure 11.15, "Sample System for Fault Analysis"" (Sheet 1 of 3)". Each branch current is described in either rectangular or polar coordinates depending on the option chosen.



```
 ...........................................................................................................
 .                  PSS/E  SHORT  CIRCUIT  OUTPUT                  TUE, OCT 15 1991  14:48   .   HOME  BUS  IS  :  .
 .                                                                                           .                     .
 .           PSSE APPLICATION GUIDE                                          FLAT            .   200 [WEST   33.0]  .
 .           UNBALANCED FAULT ANALYSIS EXAMPLE                               CONDITIONS      .                     .
 .                                                                                           .                     .
 .                 ***  FAULTED  BUS  IS :  200 [WEST   33.0]  ***                           .    0  LEVELS  AWAY  .
 ...........................................................................................................

 AT BUS   200 [WEST    33.0] AREA   1        (PU) V+: / 0.0000/    0.00        (PU) VA: / 0.0000/    0.00    V0: / 0.1167/  179.75
                                                                                    V+: / 0.4915/   -0.14    V-: / 0.3748/  179.90

 THEV. R, X, X/R: POSITIVE  0.00769  0.57262   74.428    NEGATIVE  0.00739  0.42198   57.137    ZERO  0.00263  0.13135   49.973

                                       T H R E E   P H A S E   F A U L T                O N E   P H A S E   F A U L T
 ------- FROM -------AREA CKT  I/Z      /I+/    AN(I+)    /Z+/    AN(Z+)  APP X/R       /IA/    AN(IA)    /ZA/    AN(ZA)  APP X/R
   100 [WEST GEN 138]   1 1   PU/PU    1.3427   -90.28   0.1500    90.00 9999.999      2.1456   -90.20   0.2280    89.87  425.970
   300 [EAST    33.0]   1 1   PU/PU    0.4045   -85.75   0.5590    79.70    5.500      0.5205   -84.57   0.6317    79.98    5.659
      TOTAL  FAULT  CURRENT  (P.U.)    1.7462   -89.23                                 2.6641   -89.10

 ...........................................................................................................
 .                  PSS/E  SHORT  CIRCUIT  OUTPUT                  TUE, OCT 15 1991  14:48   .   HOME  BUS  IS  :  .
 .                                                                                           .                     .
 .           PSSE APPLICATION GUIDE                                          FLAT            .   200 [WEST   33.0]  .
 .           UNBALANCED FAULT ANALYSIS EXAMPLE                               CONDITIONS      .                     .
 .                                                                                           .                     .
 .                 ***  FAULTED  BUS  IS :  200 [WEST   33.0]  ***                           .    1  LEVELS  AWAY  .
 ...........................................................................................................

 AT BUS   100 [WEST GEN 138] AREA   1        (PU) V+: / 0.2014/   -0.28        (PU) VA: / 0.3118/   -0.30    V0: / 0.0100/ -176.86
                                                                                    V+: / 0.5939/   -0.14    V-: / 0.2720/  179.93

                                       T H R E E   P H A S E   F A U L T                O N E   P H A S E   F A U L T
 ------- FROM -------AREA CKT  I/Z      /I+/    AN(I+)    /Z+/    AN(Z+)  APP X/R       /IA/    AN(IA)    /ZA/    AN(ZA)  APP X/R
 MACHINE 1                    PU/      0.4607   -89.93                                 0.4993   -89.78
 MACHINE 2                    PU/      0.4607   -89.93                                 0.4993   -89.78
   200 [WEST    33.0]   1 1   PU/PU    1.3427    89.72   0.0000     0.00    0.000      1.3678    89.83   0.0000     0.00    0.000
   500 [CENTER   138]   1 1   PU/PU    0.4213   -91.04   0.5782    88.65   42.347      0.3693   -91.23   0.9940    89.65  165.498

 AT BUS   300 [EAST    33.0] AREA   1        (PU) V+: / 0.2261/   -6.06        (PU) VA: / 0.3288/   -4.59    V0: / 0.0167/ -171.08
                                                                                    V+: / 0.6060/   -1.23    V-: / 0.2618/ -177.66

                                       T H R E E   P H A S E   F A U L T                O N E   P H A S E   F A U L T
 ------- FROM -------AREA CKT  I/Z      /I+/    AN(I+)    /Z+/    AN(Z+)  APP X/R       /IA/    AN(IA)    /ZA/    AN(ZA)  APP X/R
   200  [WEST    33.0]  1  1  PU/PU    0.4045    94.25   0.0000    0.00    0.000       0.5205   95.43   0.0000     0.00    0.000
   400  [EAST     138]  1  1  PU/PU    0.4045   -85.75   0.7071   81.87    7.000       0.5205  -84.57   1.0001    82.96    8.101
```


Figure 11.54. Output from ASCC from Dialog in Figure 11.53, “Dialog to Apply Activity ASCC to System Shown in Figure 11.15, “Sample System for Fault Analysis”” (Sheet 1 of 3)

```
               PSS/E  SHORT  CIRCUIT  OUTPUT                   TUE, OCT 15 1991  14:48     HOME  BUS  IS  :

          PSSE APPLICATION GUIDE                                            FLAT           200 [WEST    33.0]
          UNBALANCED FAULT ANALYSIS EXAMPLE                              CONDITIONS

                    ***  FAULTED  BUS  IS :   200 [WEST    33.0]  ***                       0  LEVELS  AWAY

       ***  LINE  OUT :   200 [WEST    33.0]  TO   100 [WEST GEN 138]  CIRCUIT 1   ***          LINE  OUT

AT BUS   200 [WEST    33.0] AREA   1       (PU) V+: / 0.0000/    0.00        (PU) VA: / 0.0000/    0.00    V0: / 0.3209/  177.56
                                                                              V+: / 0.6372/   -0.85    V-: / 0.3165/ -179.24

THEV. R, X, X/R: POSITIVE  0.10803  1.17833   10.907     NEGATIVE  0.10722  1.02605    9.570     ZERO  0.16665  1.03273    6.197

                                            T H R E E   P H A S E   F A U L T                 O N E   P H A S E   F A U L T
------- FROM -------AREA CKT  I/Z       /I+/     AN(I+)    /Z+/     AN(Z+)  APP X/R     /IA/     AN(IA)    /ZA/     AN(ZA)  APP X/R
  100 [WEST GEN 138]    1 1   PU/PU    0.0000      0.00   0.0000      0.00    0.000    0.0000      0.00   0.0000      0.00    0.000
  300 [EAST    33.0]    1 1   PU/PU    0.8451    -84.76   0.5590     79.70    5.500    0.9204    -83.27   0.6721     79.52    5.408
      TOTAL  FAULT  CURRENT  (P.U.)    0.8451    -84.76                                0.9204    -83.27

               PSS/E  SHORT  CIRCUIT  OUTPUT                   TUE, OCT 15 1991  14:48     HOME  BUS  IS  :

          PSSE APPLICATION GUIDE                                            FLAT           200 [WEST    33.0]
          UNBALANCED FAULT ANALYSIS EXAMPLE                              CONDITIONS

                    ***  FAULTED  BUS  IS :   200 [WEST    33.0]  ***                       1  LEVELS  AWAY

       ***  LINE  OUT :   200 [WEST    33.0]  TO   100 [WEST GEN 138]  CIRCUIT 1   ***          LINE  OUT

AT BUS   100 [WEST GEN 138] AREA   1       (PU) V+: / 0.6748/   -3.12        (PU) VA: / 0.7819/   -2.03    V0: / 0.0275/ -179.05
                                                                              V+: / 0.8821/   -1.07    V-: / 0.0739/ -171.55

                                            T H R E E   P H A S E   F A U L T                 O N E   P H A S E   F A U L T
------- FROM -------AREA CKT  I/Z       /I+/     AN(I+)    /Z+/     AN(Z+)  APP X/R     /IA/     AN(IA)    /ZA/     AN(ZA)  APP X/R
MACHINE 1                     PU/      0.1894    -83.58                                0.2024    -84.28
MACHINE 2                     PU/      0.1894    -83.58                                0.2024    -84.28
  200 [WEST    33.0]    1 1   PU/PU    0.0000      0.00   0.0000      0.00    0.000    0.0000      0.00   0.0000      0.00    0.000
  500 [CENTER   138]    1 1   PU/PU    0.3788     96.42   1.6797    -99.44    6.017    0.4048     95.72   1.9541    -97.63    7.470

AT BUS   300 [EAST    33.0] AREA   1       (PU) V+: / 0.4724/   -5.07        (PU) VA: / 0.6186/   -3.75    V0: / 0.0460/ -173.27
                                                                              V+: / 0.8085/   -1.43    V-: / 0.1461/ -174.14

                                            T H R E E   P H A S E   F A U L T                 O N E   P H A S E   F A U L T
------- FROM -------AREA CKT  I/Z       /I+/     AN(I+)    /Z+/     AN(Z+)  APP X/R     /IA/     AN(IA)    /ZA/     AN(ZA)  APP X/R
 200 [WEST     33.0]    1 1  PU/PU     0.8451     95.24   0.0000      0.00    0.000    0.9204     96.73   0.0000    0.00      0.000
 400 [EAST      138]    1 1  PU/PU     0.8451    -84.76   0.7071     81.87    7.000    0.9204    -83.27   1.2456   81.56      6.741
```

Home bus is still 200 but branch 200 to 100 is now open

This block gives conditions right here

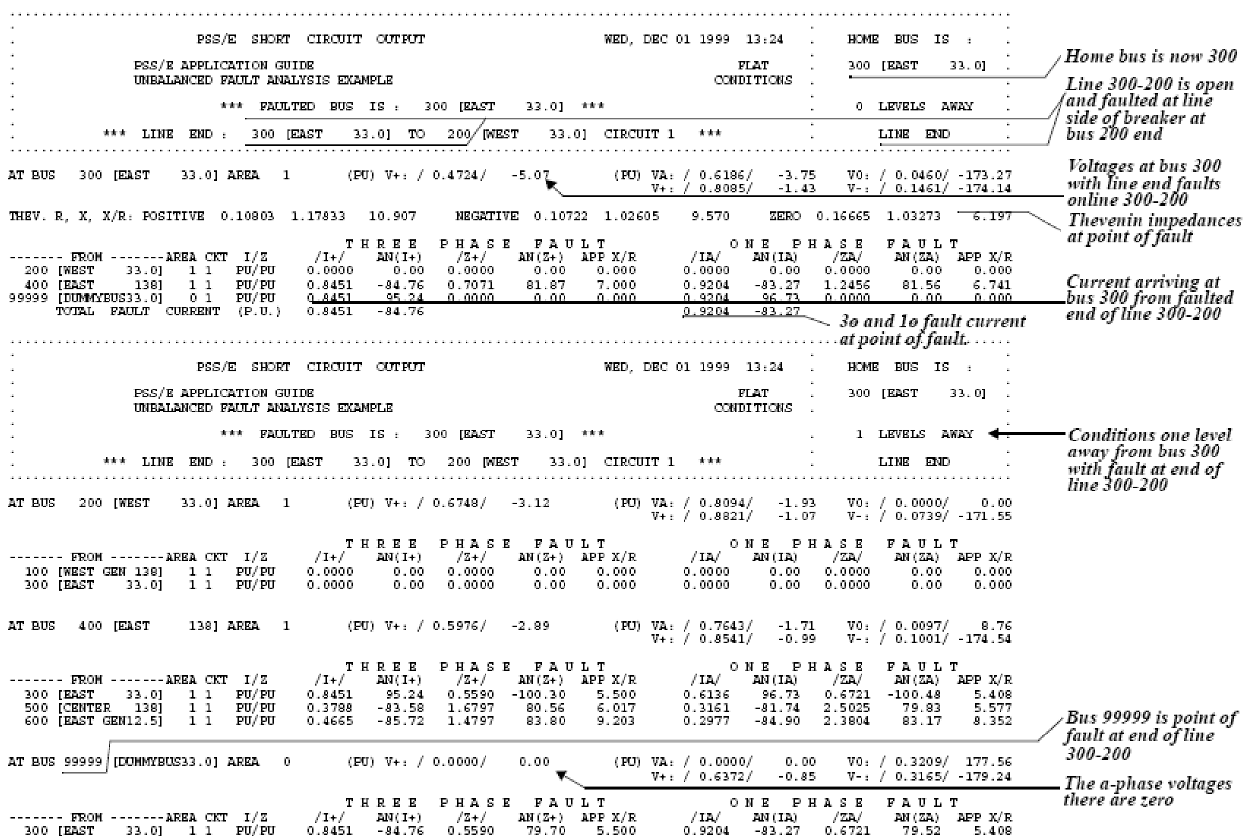
The a-phase voltages are zero at faulted bus

No contributions from bus 100, branch 100-200 is open

Output block for conditions one level away

No contribution in branch 200-100, it is open

Figure 11.55. Output from ASCC - from Dialog in Figure 11.53, “Dialog to Apply Activity ASCC to System Shown in Figure 11.15, “Sample System for Fault Analysis”” (Sheet 2 of 3)



```
.................................................................................................
.                                                                          .                   .
.                PSS/E  SHORT  CIRCUIT  OUTPUT              WED, DEC 01 1999  13:24  .  HOME  BUS  IS  :  .
.                                                                          .                   .
.           PSS/E APPLICATION GUIDE                                  FLAT  .  300 [EAST    33.0] .
.           UNBALANCED FAULT ANALYSIS EXAMPLE                  CONDITIONS  .                   .
.                                                                          .                   .
.                 ***  FAULTED  BUS  IS :   300 [EAST    33.0]  ***        .   0  LEVELS  AWAY .
.                                                                          .                   .
.       ***  LINE  END :   300 [EAST    33.0]  TO   200 [WEST    33.0]  CIRCUIT 1   ***  .  LINE  END  .
.................................................................................................

AT BUS   300 [EAST    33.0] AREA   1       (PU) V+: / 0.4724/   -5.07       (PU) VA: / 0.6186/   -3.75    V0: / 0.0460/ -173.27
                                                                                V+: / 0.8085/   -1.43    V-: / 0.1461/ -174.14

THEV. R, X, X/R: POSITIVE  0.10803  1.17833   10.907    NEGATIVE  0.10722  1.02605    9.570    ZERO  0.16665  1.03273    6.197

                                   T H R E E   P H A S E   F A U L T          O N E   P H A S E   F A U L T
------- FROM -------AREA CKT  I/Z     /I+/    AN(I+)   /Z+/    AN(Z+)  APP X/R     /IA/    AN(IA)   /ZA/    AN(ZA)  APP X/R
  200 [WEST    33.0]  1 1   PU/PU   0.0000     0.00  0.0000     0.00    0.000    0.0000     0.00  0.0000     0.00    0.000
  400 [EAST     138]  1 1   PU/PU   0.8451   -84.76  0.7071    81.87    7.000    0.9204   -83.27  1.2456    81.56    6.741
99999 [DUMMYBUS33.0]  0 1   PU/PU   0.8451    95.24  0.0000     0.00    0.000    0.9204    96.73  0.0000     0.00    0.000
     TOTAL  FAULT  CURRENT  (P.U.)  0.8451   -84.76                              0.9204   -83.27
.................................................................................................
.                                                                          .                   .
.                PSS/E  SHORT  CIRCUIT  OUTPUT              WED, DEC 01 1999  13:24  .  HOME  BUS  IS  :  .
.                                                                          .                   .
.           PSS/E APPLICATION GUIDE                                  FLAT  .  300 [EAST    33.0] .
.           UNBALANCED FAULT ANALYSIS EXAMPLE                  CONDITIONS  .                   .
.                                                                          .                   .
.                 ***  FAULTED  BUS  IS :   300 [EAST    33.0]  ***        .   1  LEVELS  AWAY .
.                                                                          .                   .
.       ***  LINE  END :   300 [EAST    33.0]  TO   200 [WEST    33.0]  CIRCUIT 1   ***  .  LINE  END  .
.................................................................................................

AT BUS   200 [WEST    33.0] AREA   1       (PU) V+: / 0.6748/   -3.12       (PU) VA: / 0.8094/   -1.93    V0: / 0.0000/    0.00
                                                                                V+: / 0.8821/   -1.07    V-: / 0.0739/ -171.55

                                   T H R E E   P H A S E   F A U L T          O N E   P H A S E   F A U L T
------- FROM -------AREA CKT  I/Z     /I+/    AN(I+)   /Z+/    AN(Z+)  APP X/R     /IA/    AN(IA)   /ZA/    AN(ZA)  APP X/R
  100 [WEST GEN 138]  1 1   PU/PU   0.0000     0.00  0.0000     0.00    0.000    0.0000     0.00  0.0000     0.00    0.000
  300 [EAST    33.0]  1 1   PU/PU   0.0000     0.00  0.0000     0.00    0.000    0.0000     0.00  0.0000     0.00    0.000

AT BUS   400 [EAST     138] AREA   1       (PU) V+: / 0.5976/   -2.89       (PU) VA: / 0.7643/   -1.71    V0: / 0.0097/    8.76
                                                                                V+: / 0.8541/   -0.99    V-: / 0.1001/ -174.54

                                   T H R E E   P H A S E   F A U L T          O N E   P H A S E   F A U L T
------- FROM -------AREA CKT  I/Z     /I+/    AN(I+)   /Z+/    AN(Z+)  APP X/R     /IA/    AN(IA)   /ZA/    AN(ZA)  APP X/R
  300 [EAST    33.0]  1 1   PU/PU   0.8451    95.24  0.5590  -100.30    5.500    0.6136    96.73  0.6721  -100.48    5.408
  500 [CENTER   138]  1 1   PU/PU   0.3788   -83.58  1.6797    80.56    6.017    0.3161   -81.74  2.5025    79.83    5.577
  600 [EAST GEN12.5]  1 1   PU/PU   0.4665   -85.72  1.4797    83.80    9.203    0.2977   -84.90  2.3804    83.17    8.352

AT BUS 99999 [DUMMYBUS33.0] AREA   0       (PU) V+: / 0.0000/    0.00       (PU) VA: / 0.0000/    0.00    V0: / 0.3209/  177.56
                                                                                V+: / 0.6372/   -0.85    V-: / 0.3165/ -179.24

                                   T H R E E   P H A S E   F A U L T          O N E   P H A S E   F A U L T
------- FROM -------AREA CKT  I/Z     /I+/    AN(I+)   /Z+/    AN(Z+)  APP X/R     /IA/    AN(IA)   /ZA/    AN(ZA)  APP X/R
  300 [EAST    33.0]  1 1   PU/PU   0.8451   -84.76  0.5590    79.70    5.500    0.9204   -83.27  0.6721    79.52    5.408
```


Figure 11.56. Output from ASCC - from Dialog in Figure 11.53, “Dialog to Apply Activity ASCC to System Shown in Figure 11.15, “Sample System for Fault Analysis”” (Sheet 3 of 3)

The APP X/R ratio is determined from the *real* and *imaginary* components of current, not from the real-power and reactive-power components. These ratios are, therefore, sensitive to the spread of voltage phase angle across the system as well as to system X/R ratio. The Imag/Real ratio of the fault current or a contribution should be interpreted as system X/R ratio *only* when the FLAT option is used in ASCC or when activity FLAT has been used to ensure that all source voltages are equal to (1 + j0) before starting fault analysis.

The other two main output selections allow the user to get full output at bus and summary outputs elsewhere or get just the fault-current summary table.

Abbreviated Output for Balanced Conditions

When ASCC is used to calculate only three-phase faults, the output format is as shown in Figure 11.57, “Abbreviated Output Format of ASCC when only Three-Phase Fault is Calculated”. This abbreviated report contains the same information as in the balanced fault part of the full output format, but has space lines removed from the header.

ASCC Summary File

Figure 11.58, “Fault Summary File #BDF1 (Breaker Duty File)(Corresponds to Figure 11.53, “Dialog to Apply Activity ASCC to System Shown in Figure 11.15, “Sample System for Fault Analysis”” and Figure 11.54, “Output from ASCC from Dialog in Figure 11.53, “Dialog to Apply Activity ASCC to System Shown in Figure 11.15, “Sample System for Fault Analysis”” (Sheet 1 of 3)”)” shows a sample summary file produced by ASCC. This file is intended to be read by postprocessing programs that need bus fault-current information to check circuit breaker loadings or otherwise review system conditions on a routine basis. While fault currents are given per-unit in this file, they can easily be converted into amperes by the postprocessing program if the base voltage field of the bus name is properly specified in setting up the fault analysis data for PSS®E.

```
ACTIVITY? ASCC

ENTER OUTPUT DEVICE CODE:
 0 FOR NO OUTPUT       1 FOR CRT TERMINAL
 2 FOR A FILE          3 FOR KMW_UP
 4 FOR QMS_LG          5 FOR HARD COPY TERMINAL
 6 FOR ALTERNATE SPOOL DEVICE: 1

ENTER :
[1 FOR] , [ 1  FOR ] , [ 1  FOR ] , [1 FOR FLAT] , [1 FOR DOUBLE]
[L - G]   [LINE OUT]   [LINE END]   [CONDITIONS]   [ PRECISION  ]
1 0 1 1 1                            Disable L-G fault calculation
ENTER FILENAME FOR RELAY OUTPUT: BFF <------------ Record fault duty results in file BFF

DIAGONALS =      7  OFF-DIAGONALS =      8  MAX SIZE =     12
BUS 99999 [DUMMYBUS    ] ISOLATED IN POS. SEQUENCE
POS. SEQUENCE: DIAGONALS =      7  OFF-DIAGONALS =      8

ENTER UP TO 20 BUS NUMBERS
200 300 <------------------------ Do calculations with 200 and 300 as home buses
 ..............................................................................................
 .                                                                               .              .
 .                   PSS®E  SHORT  CIRCUIT  OUTPUT                 TUE, OCT 15 1991  14:57  .   HOME  BUS  IS  :    .
 .                                                                               .              .
 .             PSSE APPLICATION GUIDE                                          FLAT     .  200 [WEST    33.0]  .
 .             UNBALANCED FAULT ANALYSIS EXAMPLE                             CONDITIONS  .                     .
 .                                                                               .              .
 .                        ***  FAULTED  BUS  IS :   200 [WEST     33.0]  ***      .  0  LEVELS  AWAY   .
 ..............................................................................................

 AT BUS    200 [WEST      33.0] AREA    1        (PU) V+:   0.0000+J 0.0000     + – SEQ voltage at bus 200

 THEV. R, X, X/R: POSITIVE  0.00769  0.57262   74.428   Positive sequence Thevenin impedance at bus 200

                                              T H R E E   P H A S E   F A U L T
 ------- FROM -------AREA CKT  I/Z      RE(I+)    IM(I+)   RE(Z+)    IM(Z+)   APP X/R
   100 [WEST GEN 138]   1 1    PU/PU    -0.0065   -1.3427   0.0000    0.1500 9999.999   Contribution arriving at bus 200
   300 [EAST     33.0]  1 1    PU/PU     0.0300   -0.4034   0.1000    0.5500    5.500
       TOTAL   FAULT  CURRENT  (P.U.)    0.0235   -1.7461
   ...............................................................................................
 .                                                                               .              .
 .                   PSS®E  SHORT  CIRCUIT  OUTPUT                 TUE, OCT 15 1991  14:57  .   HOME  BUS  IS  :    .
 .                                                                               .              .
 .             PSSE APPLICATION GUIDE                                          FLAT     .  200 [WEST    33.0]  .
 .             UNBALANCED FAULT ANALYSIS EXAMPLE                             CONDITIONS  .                     .
 .                                                                               .              .
 .                        ***  FAULTED  BUS  IS :   200 [WEST     33.0]  ***      .  1  LEVELS  AWAY   .
 ..............................................................................................

 AT BUS    100 [WEST GEN 138] AREA    1        (PU) V+:  0.2014-J 0.0010     Positive sequence voltage on
                                                                              bus 100 with fault at 200

                                              T H R E E   P H A S E   F A U L T
 ------- FROM -------AREA CKT  I/Z      RE(I+)    IM(I+)   RE(Z+)    IM(Z+)   APP X/R
```

Figure 11.57. Abbreviated Output Format of ASCC when only Three-Phase Fault is Calculated

3	200			1.7462	74.4275	WEST	33.0		
1	200			2.6641	63.5861	WEST	33.0		
3	200	100	1	0.8451	10.9069	WEST	33.0	WEST GEN	138
1	200	100	1	0.9204	8.4762	WEST	33.0	WEST GEN	138
30	200	100	1	0.7503	12.2954	WEST	33.0	WEST GEN	138
10	200	100	1	0.0000	9999.9990	WEST	33.0	WEST GEN	138
3	200	300	1	1.5914	78.2021	WEST	33.0	EAST	33.0
1	200	300	1	2.3914	82.2371	WEST	33.0	EAST	33.0
30	200	300	1	0.8451	10.9069	WEST	33.0	EAST	33.0
10	200	300	1	0.9204	8.4762	WEST	33.0	EAST	33.0
3	300			1.7462	74.4277	EAST	33.0		
1	300			2.6641	63.5861	EAST	33.0		
3	300	200	1	1.5914	78.2023	EAST	33.0	WEST	33.0
1	300	200	1	2.3914	82.2372	EAST	33.0	WEST	33.0
30	300	200	1	0.8451	10.9069	EAST	33.0	WEST	33.0
10	300	200	1	0.9204	8.4762	EAST	33.0	WEST	33.0
3	300	400	1	0.8451	10.9069	EAST	33.0	EAST	138
1	300	400	1	0.9204	8.4762	EAST	33.0	EAST	138
30	300	400	1	0.7503	12.2954	EAST	33.0	EAST	138
10	300	400	1	0.0000	9999.9990	EAST	33.0	EAST	138

Home bus is 200

Home bus is 300

Open branch if line-out or line-end fault

Fault current, per unit

X/R ratio of system at point of fault

Bus names corresponding to bus numbers at left

3 = Three-phase fault at home bus
1 = One-phase fault at home bus
30 = Three-phase fault at far end of open line
10 = One-phase fault at far end of open line

Figure 11.58. Fault Summary File #BDF1 (Breaker Duty File)(Corresponds to Figure 11.53, "Dialog to Apply Activity ASCC to System Shown in Figure 11.15, "Sample System for Fault Analysis"" and Figure 11.54, "Output from ASCC from Dialog in Figure 11.53, "Dialog to Apply Activity ASCC to System Shown in Figure 11.15, "Sample System for Fault Analysis"" (Sheet 1 of 3)")

11.5. Network Reduction for Fault Analysis

11.5.1. Activity SCEQ

While network reduction for fault analysis work could be handled with the standard equivalent handling activities covered in Chapter 8, *Equivalents*, it is usually better to use activity SCEQ, which is designed specifically for fault analysis applications. Activity SCEQ applies all of its operations to all three sequences in parallel, using the same topological boundary definitions for each, as shown in Figure 11.59, "Operation of All Three Sequences in Parallel by Activity SCEQ". Like the equivalent handling of activity EEQV, SCEQ handles all steps of the equivalencing process automatically so that its single execution, in effect, accomplishes the following tasks:

- Separates the external system in the working file.
- Builds an equivalent.
- Replaces the detailed external system model with the equivalent.
- Rejoins the study system onto the equivalent.

In a single step, activity SCEQ, then, replaces a full system model in the working file with a reduced model consisting of detailed study system and equivalenced external system. The boundary buses of the external system are retained so that tie branches appear as real system elements in the reduced system model (see Figure 11.60, "Operation of Activity SCEQ Replacement of External System with Equivalent"). Activity SCEQ can be called with the standard suffixes to define the subsystem to be equivalenced.

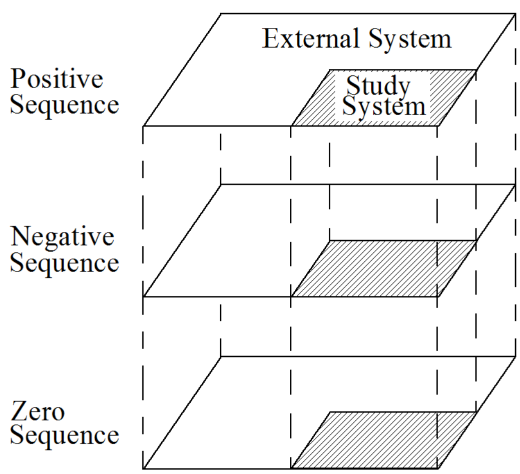


Figure 11.59. Operation of All Three Sequences in Parallel by Activity SCEQ

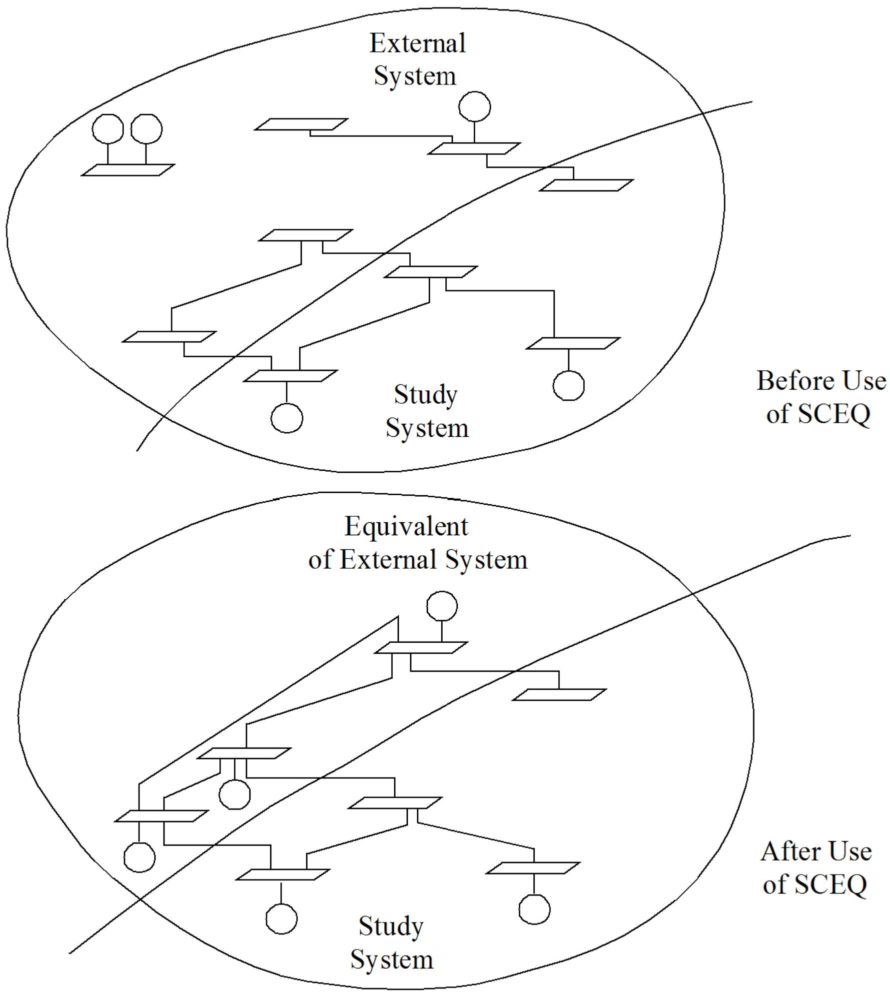


Figure 11.60. Operation of Activity SCEQ Replacement of External System with Equivalent

SCEQ runs a simple network reduction without regard to loads, transformer phase shift, or pre-event voltages. All generators in the external system are represented by simple Norton equivalents so that their effective impedances (i.e., Norton shunt admittances) and positive-sequence source currents can be transferred to the boundary buses by standard network mathematics. Activity SCEQ operates on a standard fault analysis model set up in accordance with Section 8.3, "Boundaries and Boundary Buses ", but with FLAT pre-event voltages (see the section called "Conditioning of the Pre-Event Voltages").

The network reduction is run by setting up the partitioned admittance matrix of the external system:

$$\begin{bmatrix} I_b \\ I_n \end{bmatrix} = \begin{bmatrix} Y_{bb} & Y_{bn} \\ Y_{nb} & Y_{nn} \end{bmatrix} \begin{bmatrix} V_b \\ V_n \end{bmatrix}$$

where:

b Denotes boundary buses.

n Denotes buses to be deleted.

I_b, I_n Contains either zero or generator Norton source current as calculated by CONG,SQ.

The generator internal impedances, Z_{pos}, Z_{neg}, Z_{zero}, where appropriate, are included in the network as shunt elements and are accounted for by the diagonal terms of the admittance matrix. The positive-sequence source currents are taken as ISORCE = (1./Z $_{pos}$). The admittance matrix and equivalent source currents of the reduced network are then obtained from the elimination formula:

$$(I_b - Y_{bn} Y_{nn}^{-1} I_n) = (Y_{bb} - Y_{bn} Y_{nn}^{-1} Y_{nb}) V_b \tag{11.1}$$

After calculating these matrix properties of the reduced network, SCEQ automatically deletes the true data for the external system from the working case and replaces it with data for the equivalent network corresponding to (10.2). This equivalent network comprises:

- Branches with series impedance but no charging capacitance or shunts, and with circuit number 99.
- Equivalent generators with rating equal to system MVA base and a nonzero positive-sequence source impedance.
- Negative- and zero-sequence source impedance for each equivalent generator.
- Positive-, negative-, and zero-sequence equivalent shunts.

This equivalent can have an equivalent generator at every boundary bus. As indicated by the left-hand side of Equation 11.1 the source currents of these generators are the compendium of source current of any real generators at the boundary bus plus equivalent source currents representing the effect of generators at deleted buses. SCEQ replaces all real generators at each boundary bus with a single equivalent generator and identifies it as such by assigning it machine number 9. SCEQ also assigns the circuit number 99 to all equivalent branches.

All shunt admittances (charging, reactors, capacitors, etc.) arising in the equivalent, except the generator Norton admittances, are collected together and included in the equivalent as a single shunt admittance at each boundary bus. These shunts and the generator Norton admittances are always connected as shunts to ground when the equivalent is used within PSS®E.

The form of the equivalent produced by SCEQ is illustrated in Figure 11.61, "Form of Sequence Equivalents Built by Activity SCEQ". Each sequence equivalent is contained in the working case as fault analysis data for equivalent branches and generators. Each equivalent is joined by real tie branches to the study system, which remains in the working case, completely unaltered by SCEQ.

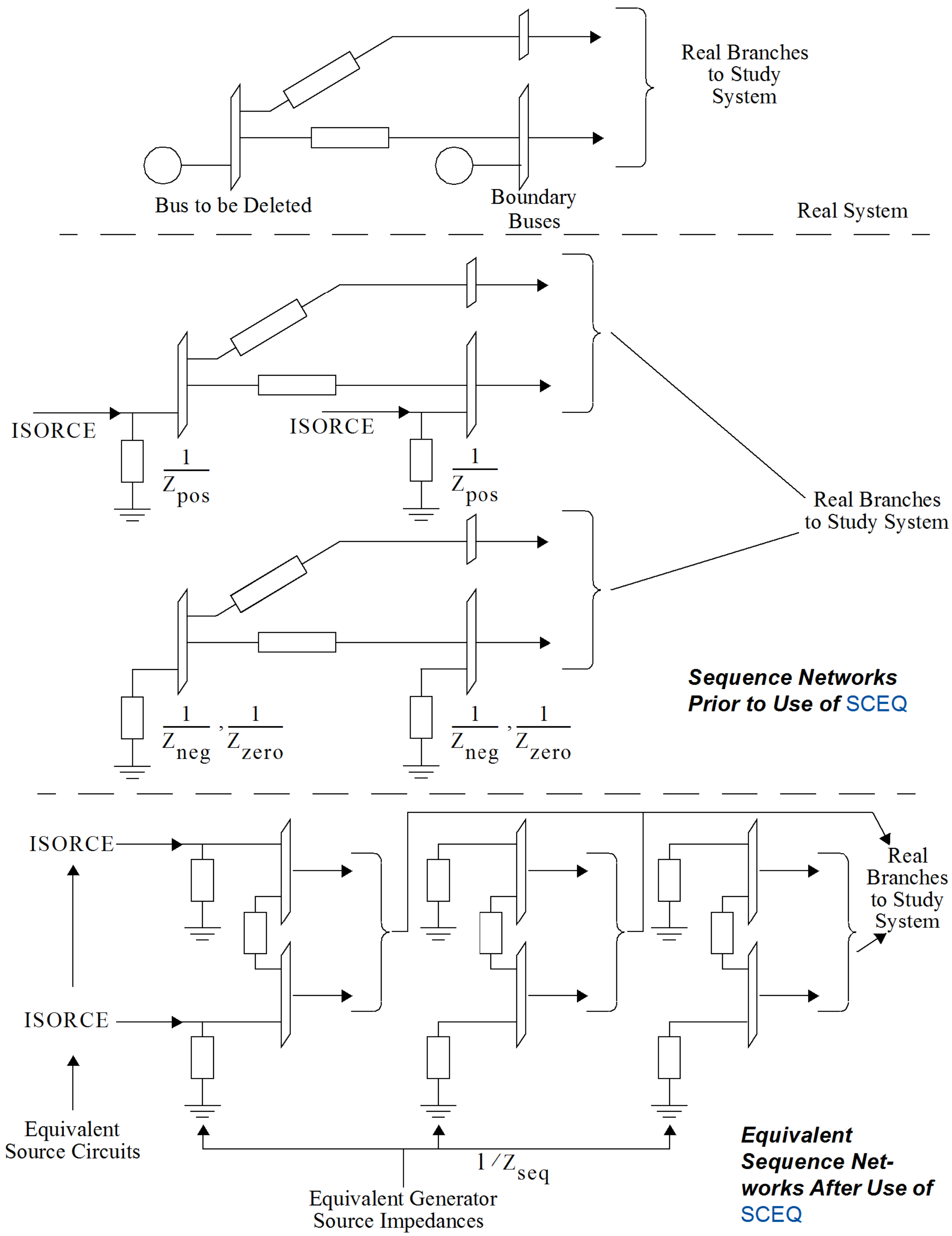


Figure 11.61. Form of Sequence Equivalents Built by Activity SCEQ

The generator positive- and negative-sequence source impedances in the working case, to which SCEQ is applied, need not be identical. If they are different, the positive-sequence and negative-sequence reduced admittance matrices will be different. The standard PSS®E negative-sequence model format recognizes differences between positive and negative sequence only in the generator source impedances, Z_{pos} and Z_{neg}. Hence when SCEQ encounters a negative-sequence equivalent branch impedance different from the corresponding positive-sequence value, it ignores it and uses the positive-sequence value in both sequences. SCEQ gives alarm messages whenever the positive and negative-sequence branch impedances differ by more than 5%. This approximation in the reduction and equivalencing of the negative sequence occurs only when generator Z_{pos} and Z_{neg} values are different and is rarely a significant influence on the accuracy of the equivalent.

11.5.2. Use of SCEQ to Reduce Network

The basic application of SCEQ is to reduce a network in situ in the working case. This type of reduction is attractive when fault analysis work is concentrated on one area of the system because it gives major reductions in the running times of activities SCEQ, SCMU, and ASCC. Because it requires generator source currents, SCEQ must be preceded by activity CONG,SQ and because it does not recognize loads or prefault system conditions, it must also be preceded by activity FLAT,CL. The correct sequence for use of SCEQ for in situ reduction follows:

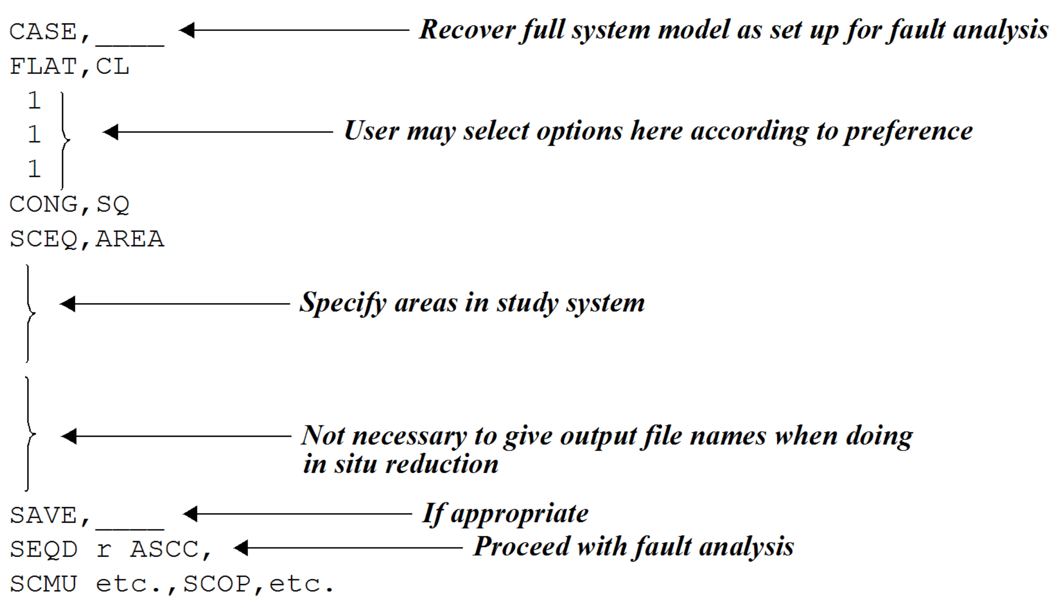


Figure 11.62. Network Reduction using Activity SCEQ

Fault analysis applied after the use of this sequence will give the same results as when the CONG,SQ and SCEQ steps are omitted. (Note: All options in FLAT,CL should be activated by a response of 1 if the FLAT option is to be used in ASCC.)

Figure 11.63, “Sample System for Fault Analysis Network Reduction” through Figure 11.69, “Output from SQLI Showing System as Reduced to Detailed Representation of Area 4 Only for Fault Analysis (Reduced Version of Figure 11.64, “Full Fault Analysis Data Listing for System Shown in Figure 11.63, “Sample System for Fault Analysis Network Reduction” (Sheet 1 of 3)”)” show an application of SCEQ. Figure 11.63, “Sample System for

Fault Analysis Network Reduction" shows the positive-sequence impedance diagram of the sample system used in Chapter 6, *Basic Power Flow Activity Applications*. This system model has several updates and additions in relation to that shown in Figures 6-12 and 6-27. In particular, three individual generators are represented at bus 1600, two individual generators are represented at bus 100, and reactors have been moved from the bus to the line sides of circuit breakers at buses 1600 and 1400. Figure 11.64, "Full Fault Analysis Data Listing for System Shown in Figure 11.63, "Sample System for Fault Analysis Network Reduction" (Sheet 1 of 3)" shows a full fault analysis data listing from activity SQLI,ALL for this system of 24 buses. The dialog for network reduction is shown in Figure 11.67, "Use of SCEQ to Reduce Network for Fault Analysis from 24 Buses to 9 Buses by Equivalencing Areas 1, 2, and 3". Activity SCEQ is instructed to leave area 4 untouched and to reduce areas 1, 2, and 3 to a boundary bus equivalent. Examination of Figure 11.63, "Sample System for Fault Analysis Network Reduction" shows that the boundary buses will be 1400 and 100 and that the equivalent will have one branch, running from 1400 to 100. SCEQ warns that the exact negative-sequence impedance for this branch should be (0.00769 + j0.07035) and then uses the positive-sequence value of (0.00039 + j0.06376) in establishing the equivalent. Figure 11.68, "Output from LIST Showing Equivalent Generators on Buses 100 and 1400" and Figure 11.69, "Output from SQLI Showing System as Reduced to Detailed Representation of Area 4 Only for Fault Analysis (Reduced Version of Figure 11.64, "Full Fault Analysis Data Listing for System Shown in Figure 11.63, "Sample System for Fault Analysis Network Reduction" (Sheet 1 of 3)")" show the data for the reduced system. The two real generators at bus 100, a boundary bus, have been replaced by a single equivalent generator and that an equivalent generator has been created at bus 1400.

With SCEQ completed, fault analysis work may be done with SEQD/SCMU/SCOP or with ASCC, just as if the original full system model was still in the working case.

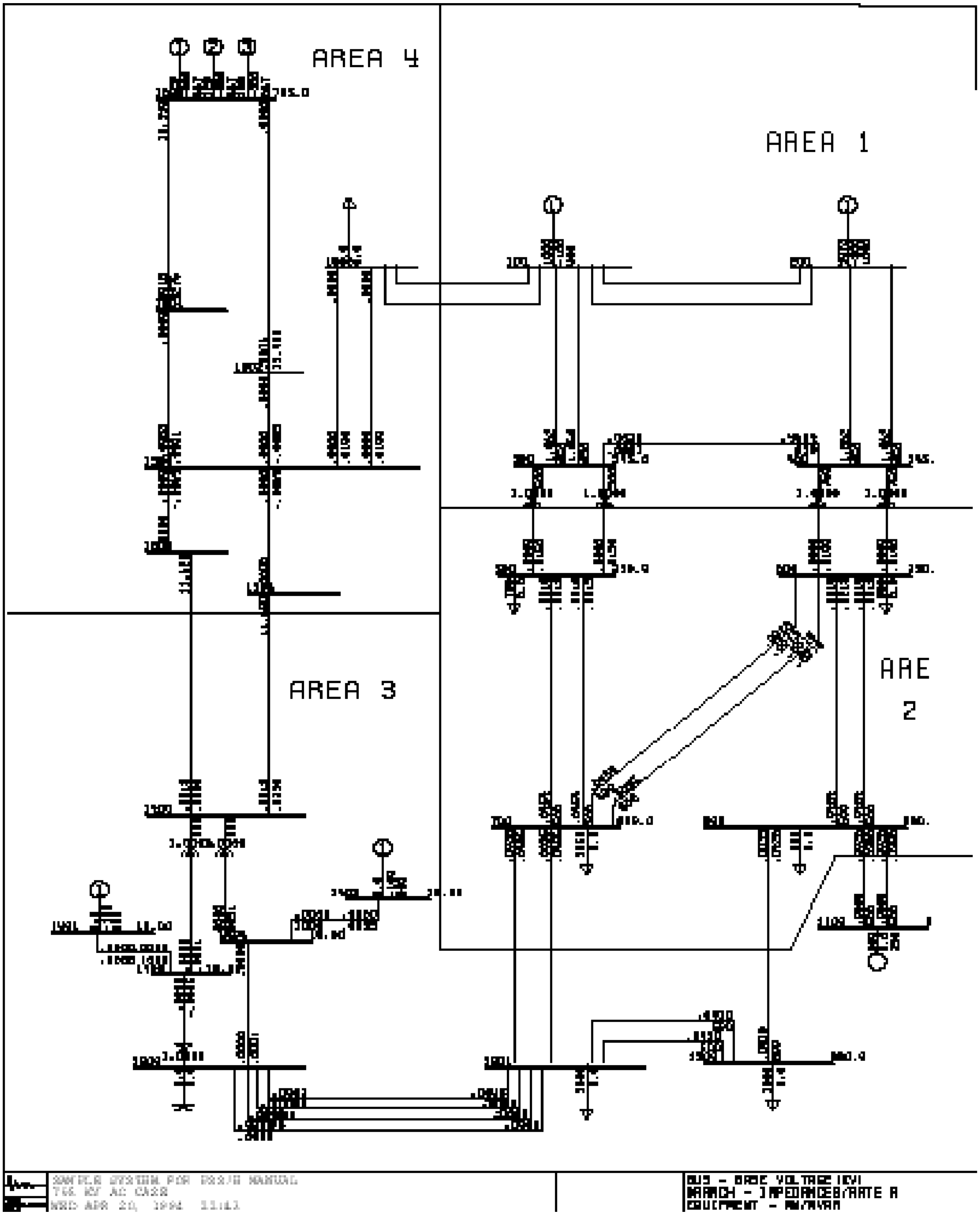


Figure 11.63. Sample System for Fault Analysis Network Reduction

```
     PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS®E      MON, OCT 21 1991  14:44
SAMPLE SYSTEM FOR PSS®E MANUAL                                         BUS DATA
765 KV AC CASE
X------ BUS -----X COD ZERO SEQ SHUNT NEG SEQ SHUNT POS SEQ SHUNT  PLOAD  QLOAD
  100 NUCLEAR  345  2   0.000   0.000  0.000  0.000  0.000  0.000  0.000  0.000
  200 HYDRO    345  2   0.000   0.000  0.000  0.000  0.000  0.000  0.000  0.000
  300 WEST     345  1   0.000   0.000  0.000  0.000  0.000  0.000  0.000  0.000
  400 EAST     345  1   0.000   0.000  0.000  0.000  0.000  0.000  0.000  0.000
  500 WESTLV   230  1   0.000   0.000  0.000  0.000  0.000  0.000  9.750  0.000
  600 EASTLV   230  1   0.000   0.000  0.000  0.000  0.000  0.000  6.500  0.000
  700 SWURB    230  1   0.000   0.000  0.000  0.000  0.000  0.000 16.250  0.000
  800 SETOUN   230  1   0.000   0.000  0.000  0.000  0.000  0.000  6.500  0.000
 1100 CATNIP   230 -2   0.000   0.000  0.000  0.000  0.000  0.000  0.000  0.000
 1200 STERML   230  1   0.000   0.000  0.000  0.000  0.000  0.000  0.000  0.000
 1201 SWIGA    230  1   0.000   0.000  0.000  0.000  0.000  0.000 13.000  0.000
 1300 SERGA    230  1   0.000   0.000  0.000  0.000  0.000  0.000 13.000  0.000
 1400               1   0.000   0.000  0.000  0.000  0.000  0.000  0.000  0.000
 1401 WCOND   18.0  2   0.000   0.000  0.000  0.000  0.000  0.000  0.000  0.000
 1402 ECOND   18.0  2   0.000   0.000  0.000  0.000  0.000  0.000  0.000  0.000
 1403 WDUM    18.0  1   0.000   0.000  0.000  0.000  0.000  0.000  0.000  0.000
 1404 EDUM    18.0  1   0.000   0.000  0.000  0.000  0.000  0.000  0.000  0.000
 1500 MIDPNT   765  1   0.000   0.000  0.000  0.000  0.000-10.000  0.000  0.000
 1501 WCAP     765  1   0.000   0.000  0.000  0.000  0.000  0.000  0.000  0.000
 1502 ECAP     765  1   0.000   0.000  0.000  0.000  0.000  0.000  0.000  0.000
 1503 WCAPA    765  1   0.000   0.000  0.000  0.000  0.000  0.000  0.000  0.000
 1504 ECAPA    765  1   0.000   0.000  0.000  0.000  0.000  0.000  0.000  0.000
 1550 MIDPNTL  345  1   0.000   0.000  0.000  0.000  0.000  0.000  0.000  0.000
 1600 MINE     765  3   0.000   0.000  0.000  0.000  0.000  0.000  0.000  0.000
```

```
     PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS®E      MON, OCT 21 1991  14:44
SAMPLE SYSTEM FOR PSS®E MANUAL                                        GENERATOR
765 KV AC CASE                                                        UNIT DATA
 BUS# ID    ZGEN  (ZERO)      ZGEN  (POS.)     ZGEN  (NEG.) MBASE   X T R A N   GENTAP
  100  1 0.0000 0.3000   0.0000 0.3000   0.0000 0.2000  1100 0.0000 0.1500 1.0250
  100  2 0.0000 0.3000   0.0000 0.3000   0.0000 0.2000  1100 0.0000 0.1500 1.0250
  200  1 0.0000 0.4000   0.0000 0.4000   0.0000 0.2500  1750 0.0000 0.1000 1.0250
 1100  1 0.4000 0.0000   0.4000 0.0000   0.0000 0.2500   500 0.0000 0.1000 1.0250
 1401  1 0.0000 0.2800   0.0000 0.2800   0.0000 0.1800   400 0.0000 0.0000 1.0000
 1402  1 0.0000 0.2800   0.0000 0.2800   0.0000 0.1800   400 0.0000 0.0000 1.0000
 1600  1 0.0000 0.3200   0.0000 0.3200   0.0000 0.2000  1100 0.0000 0.1200 1.0250
 1600  2 0.0000 0.3200   0.0000 0.3200   0.0000 0.2000  1100 0.0000 0.1200 1.0250
 1600  3 0.0000 0.3200   0.0000 0.3200   0.0000 0.2000  1100 0.0000 0.1200 1.0250
```

```
     PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS®E      MON, OCT 21 1991  14:44
SAMPLE SYSTEM FOR PSS®E MANUAL                                      BRANCH DATA
765 KV AC CASE
 FROM      TO  CKT R, X, B  (POS. AND NEG.)     R, X, B  (ZERO SEQ.) STAT RATIO  ANGLE
  100     200   1   0.0025  0.0227  0.4654  0.0050  0.0610  1.2000 1
         MUTUAL       100      200  CKT 2   0.0000  0.0200

  100     200   2   0.0025  0.0227  0.4654  0.0050  0.0610  1.2000 1
         MUTUAL       100      200  CKT 1   0.0000  0.0200

  100     300   1   0.0100  0.0906  1.8617  0.0200  0.2600  4.1000 1
         MUTUAL       100      300  CKT 2   0.0000  0.1000

  100     300   2   0.0100  0.0906  1.8617  0.0200  0.2600  4.1000 1
         MUTUAL       100      300  CKT 1   0.0000  0.1000

  100    1550   1   0.0013  0.0114  0.2327  0.0039  0.0400  0.7000 1
         MUTUAL       100     1550  CKT 2   0.0000  0.0150

  100    1550   2   0.0013  0.0114  0.2327  0.0039  0.0400  0.7000 1
         MUTUAL       100     1550  CKT 1   0.0000  0.0150
```

Figure 11.64. Full Fault Analysis Data Listing for System Shown in Figure 11.63, "Sample System for Fault Analysis Network Reduction" (Sheet 1 of 3)

```
    200     400    1   0.0100  0.0906  1.8617  0.0200  0.2600  4.1000 1
              MUTUAL      200     400  CKT 2   0.0000  0.1000

    200     400    2   0.0100  0.0906  1.8617  0.0200  0.2600  4.1000 1
              MUTUAL      200     400  CKT 1   0.0000  0.1000

    300     400    1   0.0025  0.0227  0.4654  0.0050  0.0610  1.2000 1
    300G    500G   1   0.0000  0.0150  0.0000  0.0000  0.0150  0.0000 1 0.9250
    300G    500G   2   0.0000  0.0150  0.0000  0.0000  0.0150  0.0000 1 0.9250
    400G    600G   1   0.0000  0.0100  0.0000  0.0000  0.0100  0.0000 1 0.9250
    400G    600G   2   0.0000  0.0100  0.0000  0.0000  0.0100  0.0000 1 0.9250
    500     700    1   0.0018  0.0213  0.0454  0.0050  0.0630  0.1400 1
              MUTUAL      500     700  CKT 2   0.0000  0.0400

    500     700    2   0.0018  0.0213  0.0454  0.0050  0.0630  0.1400 1
              MUTUAL      500     700  CKT 1   0.0000  0.0400

    600     700    1   0.0018  0.0213  0.0454  0.0050  0.0630  0.1400 1
              MUTUAL      600     700  CKT 2   0.0000  0.0400

    600     700    2   0.0018  0.0213  0.0454  0.0050  0.0630  0.1400 1
              MUTUAL      600     700  CKT 1   0.0000  0.0400

    600     800    1   0.0018  0.0213  0.0454  0.0050  0.0630  0.1400 1
              MUTUAL      600     800  CKT 2   0.0000  0.0400

    600     800    2   0.0018  0.0213  0.0454  0.0050  0.0630  0.1400 1
              MUTUAL      600     800  CKT 1   0.0000  0.0400

    700    1201    1   0.0035  0.0426  0.0910  0.0090  0.1250  0.2700 1
              MUTUAL      700    1201  CKT 2   0.0000  0.0600

    700    1201    2   0.0035  0.0426  0.0910  0.0090  0.1250  0.2700 1
              MUTUAL      700    1201  CKT 1   0.0000  0.0600

    800    1100    1   0.0026  0.0320  0.0680  0.0075  0.1000  0.1900 1
              MUTUAL      800    1100  CKT 2   0.0000  0.0500

1      PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS®E      MON, OCT 21 1991  14:44
 SAMPLE SYSTEM FOR PSS®E MANUAL                                   BRANCH DATA
 765 KV AC CASE
  FROM      TO  CKT R, X, B (POS. AND NEG.)    R, X, B (ZERO SEQ.) STAT RATIO  ANGLE
    800    1100    2   0.0026  0.0320  0.0680  0.0075  0.1000  0.1900 1
              MUTUAL      800    1100  CKT 1   0.0000  0.0500

    800    1300    1   0.0035  0.0426  0.0910  0.0100  0.1300  0.2700 1
   1200    1201    1   0.0002  0.0020  0.0045  0.0003  0.0060  0.0130 1
              MUTUAL     1200    1201  CKT 2   0.0000  0.0040
              MUTUAL     1200    1201  CKT 3   0.0000  0.0020
              MUTUAL     1200    1201  CKT 4   0.0000  0.0020

   1200    1201    2   0.0002  0.0020  0.0045  0.0003  0.0060  0.0130 1
              MUTUAL     1200    1201  CKT 1   0.0000  0.0040
              MUTUAL     1200    1201  CKT 3   0.0000  0.0020
              MUTUAL     1200    1201  CKT 4   0.0000  0.0020

   1200    1201    3   0.0002  0.0020  0.0045  0.0003  0.0060  0.0130 1
              MUTUAL     1200    1201  CKT 1   0.0000  0.0020
              MUTUAL     1200    1201  CKT 2   0.0000  0.0020
              MUTUAL     1200    1201  CKT 4   0.0000  0.0040

   1200    1201    4   0.0002  0.0020  0.0045  0.0003  0.0060  0.0130 1
              MUTUAL     1200    1201  CKT 1   0.0000  0.0020
              MUTUAL     1200    1201  CKT 2   0.0000  0.0020
              MUTUAL     1200    1201  CKT 3   0.0000  0.0040

   1200G   1403G   1   0.0000 -0.0005  0.0000  0.0000 -0.0005  0.0000 1 1.0000
   1200G   1404G   1   0.0000 -0.0005  0.0000  0.0000 -0.0005  0.0000 1 1.0000
   1201    1300    1   0.0035  0.0426  0.0910  0.0100  0.1250  0.2700 1
              MUTUAL     1201    1300  CKT 2   0.0000  0.0600
```

Figure 11.65. Full Fault Analysis Data Listing for System Shown in Figure 11.63, "Sample System for Fault Analysis Network Reduction" (Sheet 2 of 3)

```
1201    1300    2   0.0035  0.0426  0.0910  0.0100  0.1250  0.2700 1
          MUTUAL     1201     1300   CKT 1   0.0000  0.0600

1400G   1403G   1   0.0000  0.0031  0.0000  0.0000  0.0038  0.0000 1 1.0000
1400G   1404G   1   0.0000  0.0031  0.0000  0.0000  0.0038  0.0000 1 1.0000
1400    1503    1   0.0013  0.0230 11.6200  0.0036  0.0700 33.0000 1
          MUTUAL     1400     1504   CKT 1   0.0000  0.0250

1400    1504    1   0.0013  0.0230 11.6200  0.0036  0.0700 33.0000 1
          MUTUAL     1400     1503   CKT 1   0.0000  0.0250

1401    1403    1   0.0000  0.0035  0.0000  0.0000  0.0000  0.0000 1
1402    1404    1   0.0000  0.0035  0.0000  0.0000  0.0000  0.0000 1
1500    1501    1   0.0000 -0.0083  0.0000  0.0000 -0.0083  0.0000 1
1500    1502    1   0.0000 -0.0083  0.0000  0.0000 -0.0083  0.0000 1
1500    1503    1   0.0000 -0.0069  0.0000  0.0000 -0.0069  0.0000 1
1500    1504    1   0.0000 -0.0069  0.0000  0.0000 -0.0069  0.0000 1
1500G   1550G   1   0.0000  0.0100  0.0000  0.0000  0.0100  0.0000 1 1.0000
1500G   1550G   2   0.0000  0.0100  0.0000  0.0000  0.0100  0.0000 1 1.0000
1501    1600    1   0.0015  0.0276 13.9400  0.0045  0.0770 36.0000 1
          MUTUAL     1502     1600   CKT 1   0.0000  0.0250

1502    1600    1   0.0015  0.0276 13.9400  0.0045  0.0770 36.0000 1
          MUTUAL     1501     1600   CKT 1   0.0000  0.0250


     PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS®E      MON, OCT 21 1991  14:44
SAMPLE SYSTEM FOR PSS®E MANUAL                                  LINE SHUNT DATA
765 KV AC CASE
 FROM     TO CKT  G,B  (FROM POS)   G,B  (TO POS)  G,B  (FROM ZER)    G,B  (TO ZER)  STAT
 1400   1503   1  0.0000-0.0500   0.0000 0.0000   0.0000 0.0000   0.0000 0.0000    1
 1400   1504   1  0.0000-0.0500   0.0000 0.0000   0.0000 0.0000   0.0000 0.0000    1
 1501   1600   1  0.0000 0.0000   0.0000-0.0500   0.0000 0.0000   0.0000 0.0000    1
 1502   1600   1  0.0000 0.0000   0.0000-0.0500   0.0000 0.0000   0.0000 0.0000    1


     PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS®E      MON, OCT 21 1991  14:44
SAMPLE SYSTEM FOR PSS®E MANUAL                                      MUTUAL DATA
765 KV AC CASE
 FROM     TO CKT      FROM     TO CKT     MUTUAL IMPEDANCE      B1        B2
  100    200   1       100    200   2       0.0000    0.0200   1.0000    1.0000
  100    300   1       100    300   2       0.0000    0.1000   1.0000    1.0000
  100   1550   1       100   1550   2       0.0000    0.0150   1.0000    1.0000
  200    400   1       200    400   2       0.0000    0.1000   1.0000    1.0000
  500    700   1       500    700   2       0.0000    0.0400   1.0000    1.0000
  600    700   1       600    700   2       0.0000    0.0400   1.0000    1.0000
  600    800   1       600    800   2       0.0000    0.0400   1.0000    1.0000
  700   1201   1       700   1201   2       0.0000    0.0600   1.0000    1.0000
  800   1100   1       800   1100   2       0.0000    0.0500   1.0000    1.0000
 1200   1201   1      1200   1201   2       0.0000    0.0040   1.0000    1.0000
 1200   1201   1      1200   1201   3       0.0000    0.0020   1.0000    1.0000
 1200   1201   1      1200   1201   4       0.0000    0.0020   1.0000    1.0000
 1200   1201   2      1200   1201   3       0.0000    0.0020   1.0000    1.0000
 1200   1201   2      1200   1201   4       0.0000    0.0020   1.0000    1.0000
 1200   1201   3      1200   1201   4       0.0000    0.0040   1.0000    1.0000
 1201   1300   1      1201   1300   2       0.0000    0.0600   1.0000    1.0000
 1400   1503   1      1400   1504   1       0.0000    0.0250   1.0000    1.0000
 1501   1600   1      1502   1600   1       0.0000    0.0250   1.0000    1.0000
```

Figure 11.66. Full Fault Analysis Data Listing for System Shown in Figure 11.63, "Sample System for Fault Analysis Network Reduction" (Sheet 3 of 3)

```
ACTIVITY? CASE SCAC2                                  Recover full system case prepared
SAMPLE SYSTEM FOR PSS®E MANUAL                        for fault analysis
765 KV AC CASE

CASE SCAC2.SAV WAS SAVED ON MON, OCT 21 1991  09:33

ACTIVITY? FLAT, CL

ENTER 1 TO SET TAP RATIOS TO UNITY: 1
ENTER 1 TO SET CHARGING TO ZERO: 1
ENTER 1 TO SET SHUNTS TO ZERO: 1

ACTIVITY? CONG, SQ
GENERATORS CONVERTED

ACTIVITY? SCEQ, AREA                                  Network reduction by area

USER SPECIFIES SUBSYSTEM TO BE EQUIVALENCED
ENTER UP TO 20 AREA NUMBERS
1, 2, 3                                               Equivalence Areas 1, 2, and 3
ENTER UP TO 20 AREA NUMBERS

REBUILDING TABLES--WAIT...
DIAGONALS =     17  OFF-DIAGONALS =    31  MAX SIZE =     40


ENTER BRANCH THRESHOLD TOLERANCE: 5                   Ignore high Z branches

EQUIVALENT BRANCH  1400 TO   100:                     Difference due to
   POSITIVE SEQUENCE Z =      0.00039      0.06376    difference between
   NEGATIVE SEQUENCE Z =      0.00769      0.07035    Zpos and Zneg
DIAGONALS =     17  OFF-DIAGONALS =    29  MAX SIZE =     36
BUS  1401 [WCOND   18.0] ISOLATED IN ZERO SEQUENCE
BUS  1402 [ECOND   18.0] ISOLATED IN ZERO SEQUENCE    That's right, OK

REBUILDING TABLES--WAIT...

ENTER RAW DATA OUTPUT FILE NAME:                      No need for files in this
ENTER SEQUENCE DATA OUTPUT FILE NAME:                 application
```

Figure 11.67. Use of SCEQ to Reduce Network for Fault Analysis from 24 Buses to 9 Buses by Equivalencing Areas 1, 2, and 3

Reduced system contains Area 4, plus boundary buses

```
SAMPLE SYSTEM FOR PSS®E MANUAL                                        BUS DATA
765 KV AC CASE
 BUS#   NAME   BSKV CODE   VOLT   ANGLE    PLOAD    QLOAD      S H U N T    AREA ZONE
  100 NUCLEAR  345    2  1.0000    0.0      0.0      0.0      0.0      0.0     1    1
 1400                 2  1.0000    0.0      0.0      0.0      0.0      0.0     3    1
 1500 MIDPNT   765    1  1.0000    0.0      0.0      0.0      0.0      0.0     4    1
 1501 WCAP     765    1  1.0000    0.0      0.0      0.0      0.0      0.0     4    1
 1502 ECAP     765    1  1.0000    0.0      0.0      0.0      0.0      0.0     4    1
 1503 WCAPA    765    1  1.0000    0.0      0.0      0.0      0.0      0.0     4    1
 1504 ECAPA    765    1  1.0000    0.0      0.0      0.0      0.0      0.0     4    1
 1550 MIDPNTL  345    1  1.0000    0.0      0.0      0.0      0.0      0.0     4    1
 1600 MINE     765    2  1.0000    0.0      0.0      0.0      0.0      0.0     4    2
```

```
SAMPLE SYSTEM FOR PSS®E MANUAL                                      GENERATING
765 KV AC CASE                                                      PLANT DATA
 BUS#   NAME   BSKV COD MCNS PGEN    QGEN    QMAX    QMIN VSCHED  VACT. REMOT PCT Q
  100 NUCLEAR  345   2   1     0.0    0.0     0.0     0.0 1.0000 1.0000
 1400                2   1     0.0    0.0     0.0     0.0 1.0000 1.0000
 1600 MINE     765   2   3     0.0    0.0 2000.0-1000.0 1.0400 1.0000
```

Equivalent generator on bus 1400

Reduction replaces two real generators with one equivalent generator

Equivalent generator ZSORCE set equal to equivalent Zpos

```
SAMPLE SYSTEM FOR PSS®E MANUAL                                       GENERATOR
765 KV AC CASE                                                       UNIT DATA
 BUS#   NAME   BSKV COD ID ST PGEN QGEN QMAX QMIN PMAX PMIN MBASE Z S O R C E    X T R A N
GENTAP
  100 NUCLEAR  345   2   9  1    0    0    0    0    0    0   100 0.0006 0.0134
 1400                2   9  1    0    0    0    0    0    0   100 0.0046 0.0315
 1600 MINE     765   2   1  1    0    0  667 -333 1610  320  1100 0.0000 0.2000
0.0000 0.1200 1.0000
 1600 MINE     765   2   2  1    0    0  667 -333 1610  320  1100 0.0000 0.2000
0.0000 0.1200 1.0000
 1600 MINE     765   2   3  1    0    0  667 -333 1610  320  1100 0.0000 0.2000
0.0000 0.1200 1.0000
```

Figure 11.68. Output from LIST Showing Equivalent Generators on Buses 100 and 1400

```
SAMPLE SYSTEM FOR PSS®E MANUAL                                             BUS DATA
765 KV AC CASE
X------ BUS -----X COD ZERO SEQ SHUNT NEG SEQ SHUNT POS SEQ SHUNT   PLOAD   QLOAD
  100 NUCLEAR  345  2    0.000    0.000  0.000   0.000  0.000  0.000  0.000  0.000
 1400               2    0.000    0.000  0.000   0.000  0.000  0.000  0.000  0.000
 1500 MIDPNT   765  1    0.000    0.000  0.000   0.000  0.000  0.000  0.000  0.000
 1501 WCAP     765  1    0.000    0.000  0.000   0.000  0.000  0.000  0.000  0.000
 1502 ECAP     765  1    0.000    0.000  0.000   0.000  0.000  0.000  0.000  0.000
 1503 WCAPA    765  1    0.000    0.000  0.000   0.000  0.000  0.000  0.000  0.000
 1504 ECAPA    765  1    0.000    0.000  0.000   0.000  0.000  0.000  0.000  0.000
 1550 MIDPNTL  345  1    0.000    0.000  0.000   0.000  0.000  0.000  0.000  0.000
 1600 MINE     765  2    0.000    0.000  0.000   0.000  0.000  0.000  0.000  0.000
```

All zero as a result of FLAT,CL

```
SAMPLE SYSTEM FOR PSS®E MANUAL                                            GENERATOR
765 KV AC CASE                                                            UNIT DATA
 BUS# ID    ZGEN (ZERO)     ZGEN (POS.)     ZGEN (NEG.) MBASE    X T R A N   GENTAP
  100   9 0.0000 0.0059  0.0006 0.0134  0.0002 0.0104   100 0.0000 0.0000 1.0000
 1400   9 0.0089 0.1885  0.0046 0.0315  0.0000 0.0218   100 0.0000 0.0000 1.0000
 1600   1 0.0000 0.3200  0.0000 0.3200  0.0000 0.2000  1100 0.0000 0.1200 1.0000
 1600   2 0.0000 0.3200  0.0000 0.3200  0.0000 0.2000  1100 0.0000 0.1200 1.0000
 1600   3 0.0000 0.3200  0.0000 0.3200  0.0000 0.2000  1100 0.0000 0.1200 1.0000
```

***Equivalent generators created by* SCEQ**

```
SAMPLE SYSTEM FOR PSS®E MANUAL                                          BRANCH DATA
765 KV AC CASE
 FROM     TO   CKT R, X, B (POS. AND NEG.)    R, X, B (ZERO SEQ.) STAT RATIO   ANGLE
  100   1400   99   0.0004  0.0638  0.0000  0.0253  0.4261  0.0000 1
  100   1550    1   0.0013  0.0114  0.0000  0.0039  0.0400  0.0000 1
          MUTUAL      100     1550  CKT 2   0.0000  0.0150

  100   1550    2   0.0013  0.0114  0.0000  0.0039  0.0400  0.0000 1
          MUTUAL      100     1550  CKT 1   0.0000  0.0150

 1400   1503    1   0.0013  0.0230  0.0000  0.0036  0.0700  0.0000 1
          MUTUAL     1400     1504  CKT 1   0.0000  0.0250

 1400   1504    1   0.0013  0.0230  0.0000  0.0036  0.0700  0.0000 1
          MUTUAL     1400     1503  CKT 1   0.0000  0.0250

 1500   1501    1   0.0000 -0.0083  0.0000  0.0000 -0.0083  0.0000 1
 1500   1502    1   0.0000 -0.0083  0.0000  0.0000 -0.0083  0.0000 1
 1500   1503    1   0.0000 -0.0069  0.0000  0.0000 -0.0069  0.0000 1
 1500   1504    1   0.0000 -0.0069  0.0000  0.0000 -0.0069  0.0000 1
 1500G  1550G   1   0.0000  0.0100  0.0000  0.0000  0.0100  0.0000 1 1.0000
 1500G  1550G   2   0.0000  0.0100  0.0000  0.0000  0.0100  0.0000 1 1.0000

 1501   1600    1   0.0015  0.0276  0.0000  0.0045  0.0770  0.0000 1
          MUTUAL     1502     1600  CKT 1   0.0000  0.0250

 1502   1600    1   0.0015  0.0276  0.0000  0.0045  0.0770  0.0000 1
          MUTUAL     1501     1600  CKT 1   0.0000  0.0250
```

***Equivalent branch created by* SCEQ**

Real branches within Area 4 and ties to equivalenced area

```
SAMPLE SYSTEM FOR PSS®E MANUAL                                          MUTUAL DATA
765 KV AC CASE
 FROM    TO CKT    FROM    TO CKT   MUTUAL IMPEDANCE        B1        B2
  100  1550   1     100  1550   2    0.0000    0.0150    1.0000    1.0000
 1400  1503   1    1400  1504   1    0.0000    0.0250    1.0000    1.0000
 1501  1600   1    1502  1600   1    0.0000    0.0250    1.0000    1.0000
```

***These two coupled branches are ties and hence unchanged by* SCEQ**

Figure 11.69. Output from SQLI Showing System as Reduced to Detailed Representation of Area 4 Only for Fault Analysis (Reduced Version of Figure 11.64, “Full Fault Analysis Data Listing for System Shown in Figure 11.63, “Sample System for Fault Analysis Network Reduction” (Sheet 1 of 3)”)

11.5.3. Output of Sequence Network Equivalents from SCEQ

Figure 11.70, "Equivalent Formed by SCEQ for Areas 1, 2 and 3 in Example Shown in Figure 11.67, "Use of SCEQ to Reduce Network for Fault Analysis from 24 Buses to 9 Buses by Equivalencing Areas 1, 2, and 3"" shows the complete set of positive-, negative-, and zero-sequence equivalents produced by activity SCEQ in Figure 11.67, "Use of SCEQ to Reduce Network for Fault Analysis from 24 Buses to 9 Buses by Equivalencing Areas 1, 2, and 3". Equivalents of this form are useful in a wide variety of analyses outside of PSS®E, such as transient network analyzer (TNA) work and analysis of sub synchronous resonance. SCEQ allows these equivalents to be put out in raw data files in the formats used by activities READ and RESQ. These files of equivalent data can be read back into PSS®E or used as source data for other programs. Figure 11.71, "Raw Data Files Describing Equivalents Built By SCEQ" shows the two files produced by SCEQ in the example of Figure 11.67, "Use of SCEQ to Reduce Network for Fault Analysis from 24 Buses to 9 Buses by Equivalencing Areas 1, 2, and 3".

SCEQ appends the value of ISORCE onto the Z_{pos} records of the sequence raw data file. This is for convenience only; it is ignored by RESQ if the file is used as input to that activity.

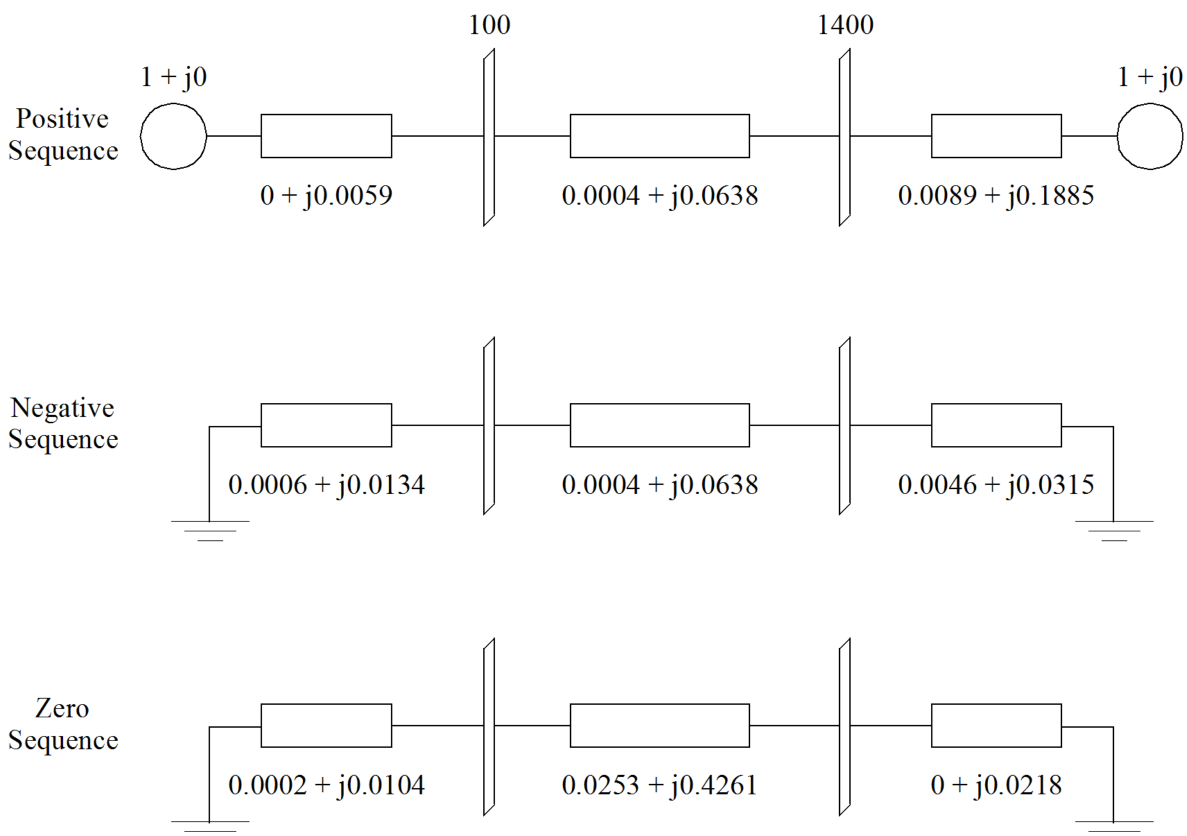


Figure 11.70. Equivalent Formed by SCEQ for Areas 1, 2 and 3 in Example Shown in Figure 11.67, "Use of SCEQ to Reduce Network for Fault Analysis from 24 Buses to 9 Buses by Equivalencing Areas 1, 2, and 3"

```
0    100.00          / MON, OCT 21 1991  17:20
SAMPLE SYSTEM FOR PSS®E MANUAL
765 KV AC CASE
 100 2     0.000     0.000     0.000     0.000    1 1.00000     0.0000 'NUCLEAR ' 345.00    1
1400 2     0.000     0.000     0.000     0.000    3 1.00000     0.0000 '         '  0.000    1
0
 100 9    0.000    0.000    0.000    0.000 1.00000     0 100.000 0.00057 0.01340 0.00000 0.00000 1.00000 1 100.0    0.000    0.000
1400 9    0.000    0.000    0.000    0.000 1.00000     0 100.000 0.00462 0.03147 0.00000 0.00000 1.00000 1 100.0    0.000    0.000
0
 100     1400 99   0.00039   0.06376 0.00000     0.00     0.00     0.00,,,    0.00000    0.00000    0.00000    0.00000 1
0
0
  1    0      0.000    9998.998 'GENSYS  '
  3    0      0.000    9998.998 'NEWLOAD '
  4    0      0.000    9998.998 'REMGEN  '
0
0
0
0
0
0
0
```

Circuit 99 denotes equivalent branch

Machine No. 9 denotes equivalent generator

a. Positive-Sequence Equivalent Data in Raw Data File Format of activity READ

Machine No. 9 denotes equivalent generator

```
0         / MON, OCT 21 1991  17:20
  100 9     0.00057    0.01340
 1400 9     0.00462    0.03147
0
  100 9     0.00015    0.01037
 1400 9     0.00004    0.02176
0
  100 9     0.00004    0.00589
 1400 9     0.00894    0.18852
0
0
0
  100  1400 99   0.02526   0.42610   0.00000   0.00000   0.00000   0.00000   0.00000
0
0
0
```

Circuit 99 denotes equivalent branch

b. Negative- And Zero-Sequence Data in Raw Data File Format of activity TRSQ

Figure 11.71. Raw Data Files Describing Equivalents Built By SCEQ

11.6. Special Situations

11.6.1. Isolated Ungrounded Subsystems

While PSS®E has no difficulty in handling situations where one or more of the sequence networks is separated into unconnected subsystems, it does require that at least one point in each subsystem be connected to ground by a finite admittance. This admittance may be provided by charging capacitance, by a shunt branch, by a generator, by transformer grounding, or by load, but it must exist. It is fairly common to encounter system conditions that isolate an ungrounded subsystem in the zero-sequence network, or in the positive and negative sequences if load charging or shunt branches are not being considered. The user of PSS®E must recognize and avoid situations involving ungrounded subsystems.

Figure 11.72, "System Configuration to Illustrate Special Situations" illustrates the possibility of isolating an ungrounded subsystem. Consider the following problem: Examine the currents in the individual phase leads and windings of the delta-wye transformer shown in Figure 11.72, "System Configuration to Illustrate Special Situations"a and consider that normal fault analysis assumptions will be made so that resistance, all shunt branches, and load are neglected. The three symmetrical component networks corresponding to Figure 11.72, "System Configuration to Illustrate Special Situations"a are shown in Figure 11.72, "System Configuration to Illustrate Special Situations"b.

Next consider the problem of solving for phase currents with these conditions:

1. A three-phase fault at bus 4.

2. A blown fuse in the a-phase transformer lead.

An immediate temptation would be to set up this situation in this sequence:

1. Use CHNG to open branch 1-2.

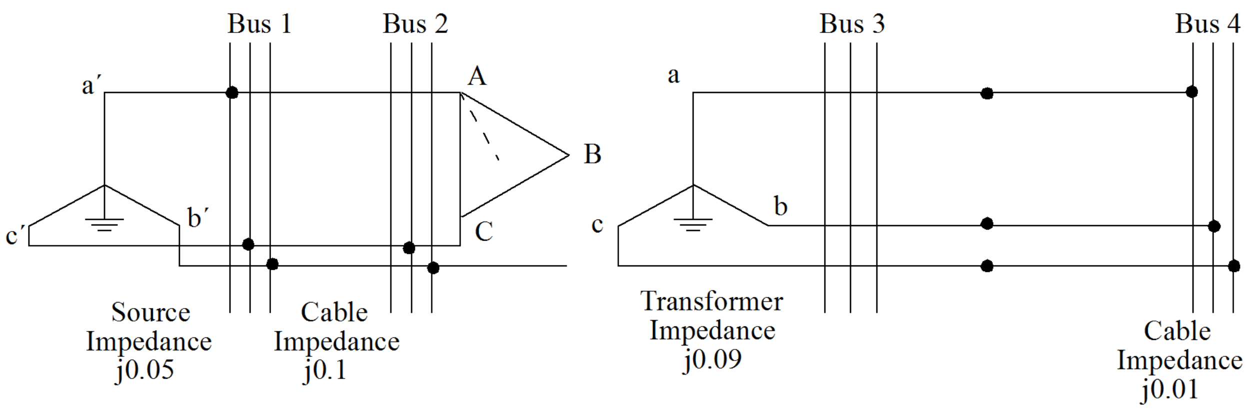
2. Run activity SCEQ.

3. Use SCMU to apply the three-phase fault at bus 4 and to close phases B and C between buses 1 and 2.

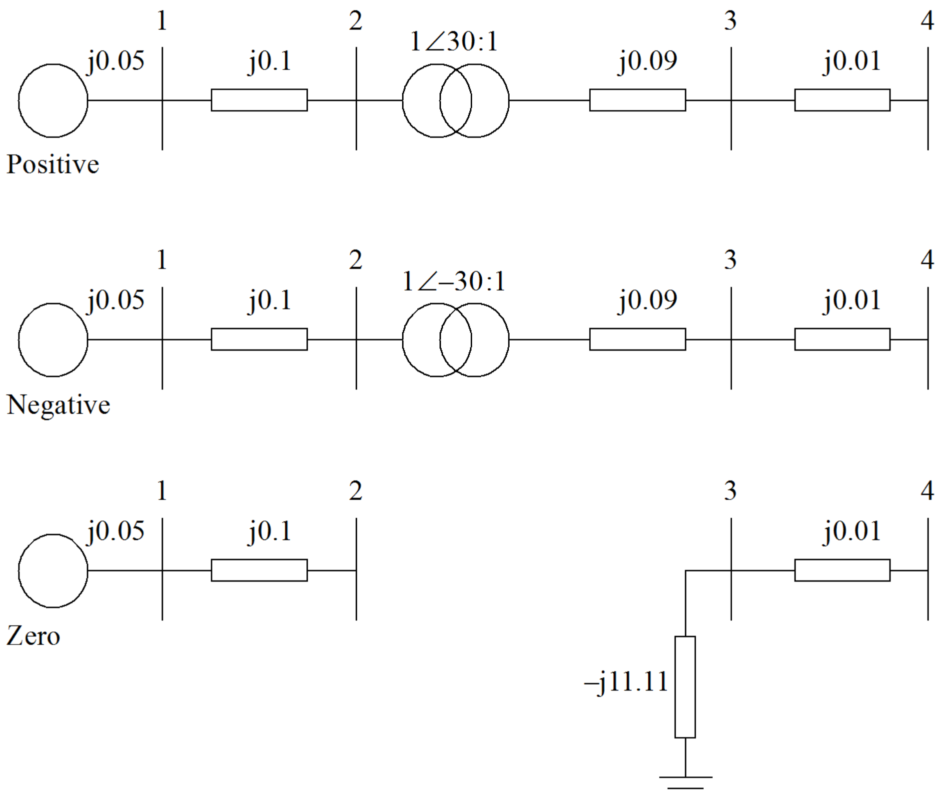
This approach is *not acceptable*, however, because in the case where the transformer between buses 2 and 3 was not grounded, the opening of branch 1-2 leaves buses 2, 3, and 4 as an isolated ungrounded subsystem in the positive- and negative-sequences, and presents SCEQ with a singular admittance matrix. The three-phase fault is *not* effective as a ground tie in this case because a fault applied by SCMU is treated as an external constraint on the network solution, not as a part of the network being solved. Two alternative ways of avoiding this problem follow:

Alternative A		Alternative B
Apply a three-phase fault with CHNG by placing a large inductive shunt at bus 4. Open branch 1-2 with CHNG. Run SEQD. Use SCMU to close two phases between buses 1 and 2.		Make no changes to the base system configuration, but proceed directly with SEQD. Use SCMU to apply the three-phase fault at bus 4. Continue using SCMU to close one phase between buses 1 and 2, with a reactance of -j0.1, as shown in Figure 11.73, "Use of Single-Phase Closed Unbalance to Cancel One Phase of an In-

Alternative A		Alternative B
		Service Branch and Produce Effect of a Single Open Phase”, to cancel all current in the opened phase.



a. Actual Configuration



b. Sequence Networks

Figure 11.72. System Configuration to Illustrate Special Situations

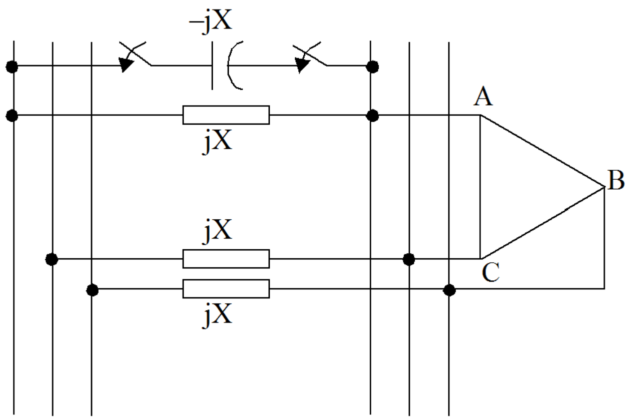


Figure 11.73. Use of Single-Phase Closed Unbalance to Cancel One Phase of an In-Service Branch and Produce Effect of a Single Open Phase

Alternative A still involves separated subsystems in all three sequence networks, but it is acceptable because each subsystem has a branch to ground.

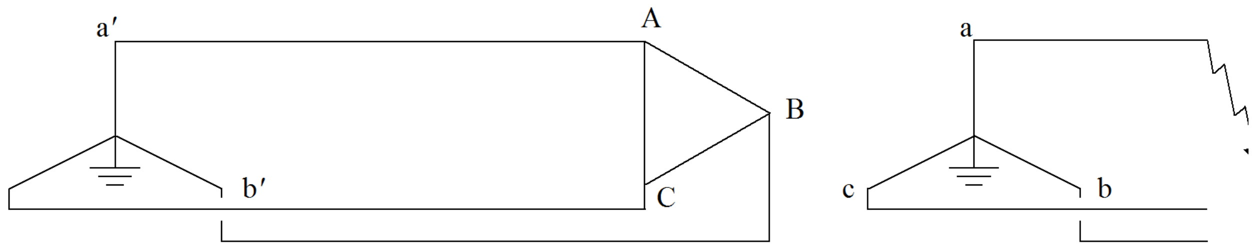
Alternative B avoids the separation in the positive- and negative-sequence networks. The resonant circuit created by the cancelling phase closure does not invalidate the solution because the cancelling branch is treated as an external constraint and not as a part of the sequence networks.

11.6.2. Singular Fault Constraints

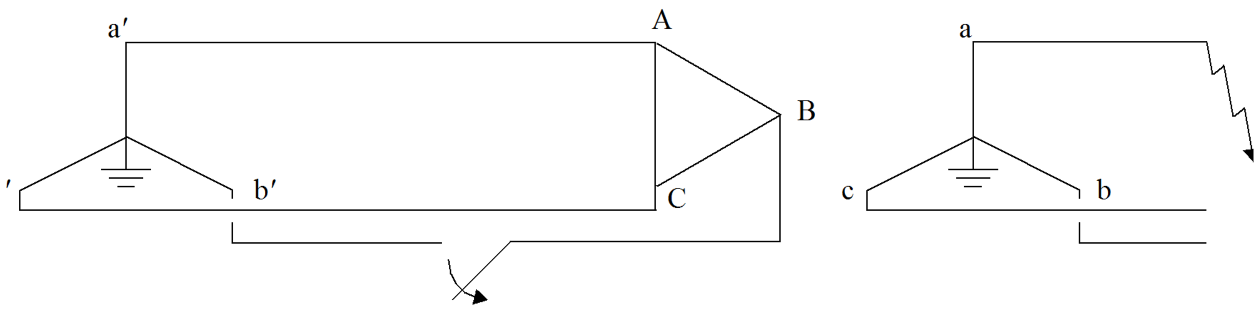
The application of simultaneous faults, especially in combinations involving open phases, can produce singular fault constraints. A singular fault constraint is a situation in which one or more node voltages or phase currents can take on an arbitrary value without violating Kirchhoff's Laws as applied to the symmetrical component networks.

The problem of singular fault constraints is best illustrated by an example. Consider first the solution of the system shown in Figure 11.72, "System Configuration to Illustrate Special Situations"a with the single unbalance of a L-G fault at the transformer secondary terminals, bus 4, as shown in Figure 11.74, "Combined Transformer Faults Illustrating Possibility of Singular Fault Constraint"a. This fault may be applied in the most straightforward manner within SCMU. It may readily be seen from inspection of Figure 11.74, "Combined Transformer Faults Illustrating Possibility of Singular Fault Constraint"a that the primary phase current, b ′ B, must be zero, and the primary a ′ A- and c ′ C-phase currents must be equal and opposite, and equal to 1 / √ 3 times secondary fault current.

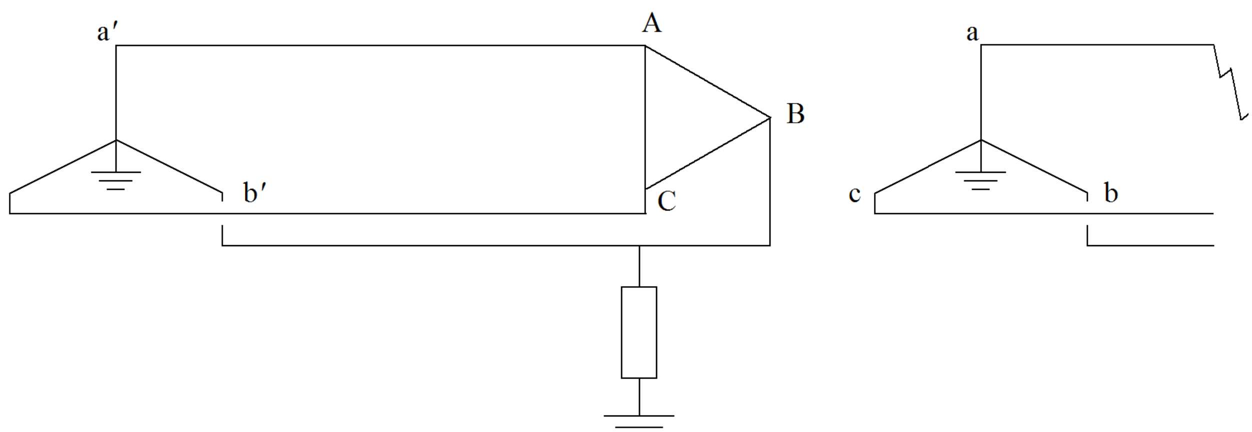
Figure 11.75, "Solution for Case of Figure 11.74, "Combined Transformer Faults Illustrating Possibility of Singular Fault Constraint"(a)" summarizes the solution dialog for this case and shows that these conditions are correctly reproduced by SCMU. The B-phase voltage at bus 2 is identical to the b-phase supply voltage, a direct consequence of the zero current in the b ′ B phase branch.



a. Simple L-G Fault



b. Add Open Primary Phase



c. Add Constraining L-G Fault at B-Phase of Bus 2

Figure 11.74. Combined Transformer Faults Illustrating Possibility of Singular Fault Constraint

```
ACTIVITY? CASE TCSC
FAULT ANALYSIS TEST CASE
D-Y TRANSFORMER

CASE TCSC.SAV WAS SAVED ON MON, OCT 28 1991  09:37

ACTIVITY? SEQD
DIAGONALS =       4  OFF-DIAGONALS =       3  MAX SIZE =       6
POS. SEQUENCE: DIAGONALS =       4  OFF-DIAGONALS =       3
NEG. SEQUENCE: DIAGONALS =       4  OFF-DIAGONALS =       3
DIAGONALS =       4  OFF-DIAGONALS =       2  MAX SIZE =       4
ZERO SEQUENCE: DIAGONALS =       4  OFF-DIAGONALS =       2

ACTIVITY? SCMU

UNBALANCES TO BE APPLIED:

LINE TO GROUND FAULT AT BUS      4   PHASE 1
  L-G Z =    0.0000E+00    0.0000E+00

ENTER 1 IF OK, 0 TO RE-SPECIFY UNBALANCES, -1 TO EXIT ACTIVITY: 1

              SEQUENCE THEVENIN IMPEDANCES AT FAULTED BUSES:

  BUS    NAME   BSKV          ZERO                POSITIVE             NEGATIVE
    4                  0.00000   0.10000     0.00000   0.25000     0.00000   0.25000

LINE TO GROUND FAULT AT BUS      4:

SEQUENCE              /V0/      AN(V0)      /V+/      AN(V+)      /V-/      AN(V-)
PHASE                 /VA/      AN(VA)      /VB/      AN(VB)      /VC/      AN(VC)

    4   (P.U.)       0.1667     150.00     0.5833     -30.00     0.4167     150.00
                     0.0000       0.00     0.9014    -136.10     0.9014      76.10

SEQUENCE              /I0/      AN(I0)      /I+/      AN(I+)      /I-/      AN(I-)
PHASE                 /IA/      AN(IA)      /IB/      AN(IB)      /IC/      AN(IC)

FROM      3 1        1.6667    -120.00     1.6667    -120.00     1.6667    -120.00
                     5.0000    -120.00     0.0000       0.00     0.0000       0.00

SEQUENCE              /V0/      AN(V0)      /V+/      AN(V+)      /V-/      AN(V-)
PHASE                 /VA/      AN(VA)      /VB/      AN(VB)      /VC/      AN(VC)

    2   (P.U.)       0.0000       0.00     0.7500       0.00     0.2500     120.00
                     0.6614      19.11     1.0000    -120.00     0.6614     100.89

SEQUENCE              /I0/      AN(I0)      /I+/      AN(I+)      /I-/      AN(I-)
PHASE                 /IA/      AN(IA)      /IB/      AN(IB)      /IC/      AN(IC)

FROM      1 1        0.0000       0.00     1.6667     -90.00     1.6667    -150.00
                     2.8867    -120.00     0.0000       0.00     2.8867      60.00

FROM      3 1        0.0000       0.00     1.6667      90.00     1.6667      30.00
                     2.8867      60.00     0.0000       0.00     2.8867    -120.00

SUM OF CONTRIBUTIONS INTO BUS      2:

    2                0.0000       0.00     0.0000       0.00     0.0000       0.00
                     0.0000       0.00     0.0000       0.00     0.0000       0.00
```

Pick up case TCSC, already solved to shift voltage at buses 3 and 4 by 30°

SCEQ ***to set up system matrices for fault solutions***

SCMU ***with L-G fault at bus 4 and phase 1***

Bus 4 has zero phase 1 voltage

Fault current is 5.0 per unit in phase 1

Bus 2 phase 2 voltage is 1.0 per unit

Equal and opposite currents in phases 1 and 3

Figure 11.75. Solution for Case of Figure 11.74, "Combined Transformer Faults Illustrating Possibility of Singular Fault Constraint"(a)

Next consider the situation shown in Figure 11.74, "Combined Transformer Faults Illustrating Possibility of Singular Fault Constraint"b in which the same secondary L-G fault is accompanied by opening of the primary b ′ B-phase lead. This situation may be set up by using Alternative B of Section 11.6.1, "Isolated Ungrounded Subsystems" to avoid isolating an ungrounded subsystem. Because the fault current in this lead was zero in the previous case, opening the lead should have no effect on the solution. Figure 11.76, "Solution for Case of Figure 11.74, "Combined Transformer Faults Illustrating Possibility of Singular Fault Constraint"(b)", which summarizes the solution dialog for this case, shows however that the combined fault produces a singular fault constraint matrix. Examination of the result indicates that:

1. All currents are, correctly, unchanged.

2. The B-phase voltage at bus 2 has a value of 1.0489 where a zero value would have been expected from examination of Figure 11.74, "Combined Transformer Faults Illustrating Possibility of Singular Fault Constraint"b.

3. As a result, the voltages at bus 4, phases b and c, now differ from the expected symmetrical values.

The singularity and anomalous result arise in this case because the symmetrical component representation of the transformer describes only its terminal-to-terminal characteristics and not its internal winding arrangements. Hence, it does not recognize the need for equal AB and BC voltages when the b ′ B lead is opened.

This fault constraint singularity may be avoided by considering an equivalent situation that constrains the B-phase voltage at bus 2. This situation is shown in Figure 11.74, "Combined Transformer Faults Illustrating Possibility of Singular Fault Constraint"c, where the previous two faults are augmented by a L-G fault of finite impedance at the B-phase of bus 2. This last fault requires the B-phase voltage at bus 2 to be zero, rather than allowing an arbitrary value, and therefore avoids the singular constraint. Inspection of Figure 11.74, "Combined Transformer Faults Illustrating Possibility of Singular Fault Constraint"c shows that this last case should give the same currents as in the previous two cases. Figure 11.77, "Solution for Case of Figure 11.74, "Combined Transformer Faults Illustrating Possibility of Singular Fault Constraint"(c)" summarizes the solution dialog and confirms that the solution is as expected.

```
ACTIVITY? SCMU

UNBALANCES TO BE APPLIED:

LINE TO GROUND FAULT AT BUS    4  PHASE 1
  L-G Z =    0.0000E+00   0.0000E+00

ONE PHASE CLOSED BETWEEN BUSES  1 AND 2  PHASE 2  Z =   0.0000E+00  -0.1000

ENTER 1 IF OK, 0 TO RE-SPECIFY UNBALANCES, -1 TO EXIT ACTIVITY: 1

              SEQUENCE THEVENIN IMPEDANCES AT FAULTED BUSES:

  BUS   NAME  BSKV           ZERO                POSITIVE              NEGATIVE
   4                 0.00000   0.10000    0.00000   0.25000    0.00000   0.25000
   1                 0.00000   0.05000    0.00000   0.05000    0.00000   0.05000
   2                 0.00000   0.15000    0.00000   0.15000    0.00000   0.15000

SINGULAR MATRIX IN CMSOL--PIVOT =   0.00000E+00  -0.14901E-06
```

SCMU to rerun the case with L-G fault at bus 4 and phase 2 open at transformer primary

Fault solution detects singular fault constraint matrix

```
LINE TO GROUND FAULT AT BUS     4:

SEQUENCE           /V0/     AN(V0)     /V+/     AN(V+)     /V-/     AN(V-)
PHASE              /VA/     AN(VA)     /VB/     AN(VB)     /VC/     AN(VC)

    4  (P.U.)     0.1667    150.00    0.5970    -23.65    0.4317    158.79
                  0.0000      0.00    0.8937   -128.73    0.9555     82.41

SEQUENCE           /I0/     AN(I0)     /I+/     AN(I+)     /I-/     AN(I-)
PHASE              /IA/     AN(IA)     /IB/     AN(IB)     /IC/     AN(IC)

FROM      3 1     1.6667   -120.00    1.6667   -120.00    1.6667   -120.00
                  5.0000   -120.00    0.0000      0.00    0.0000      0.00

SEQUENCE           /V0/     AN(V0)     /V+/     AN(V+)     /V-/     AN(V-)
PHASE              /VA/     AN(VA)     /VB/     AN(VB)     /VC/     AN(VC)

    1  (P.U.)     0.0000      0.00    0.9167      0.00    0.0833    120.00
                  0.8780      4.71    1.0000   -120.00    0.8780    115.29

    2  (P.U.)     0.0668    -38.61    0.7629      4.96    0.2682    134.25
                  0.6614     19.11    1.0489   -109.12    0.6614    100.89

SEQUENCE           /V0/     AN(V0)     /V+/     AN(V+)     /V-/     AN(V-)
PHASE              /VA/     AN(VA)     /VB/     AN(VB)     /VC/     AN(VC)

    2  (P.U.)     0.0668    -38.61    0.7629      4.96    0.2682    134.25
                  0.6614     19.11    1.0489   -109.12    0.6614    100.89

SEQUENCE           /I0/     AN(I0)     /I+/     AN(I+)     /I-/     AN(I-)
PHASE              /IA/     AN(IA)     /IB/     AN(IB)     /IC/     AN(IC)

FROM      1       0.6677   -128.61    0.6677     -8.61    0.6677    111.39
                  0.0000      0.00    2.0030   -128.61    0.0000      0.00

FROM      1 1     0.6677     51.39    1.7001   -112.85    1.8860   -129.51
                  2.8867   -120.00    2.0030     51.39    2.8867     60.00
```

Zero voltage at bus 4 phase 1

Phase 1 fault current unchanged at bus 4

Phase 2 voltage at bus 2 is now 1.0489 per unit

2.003 per-unit current in closed phase cancels out to leave phase currents unchanged

Figure 11.76. Solution for Case of Figure 11.74, "Combined Transformer Faults Illustrating Possibility of Singular Fault Constraint"(b)

```
ACTIVITY? SCMU
```

SCMU to rerun the case with L-G fault at bus 4, phase 2 open at transformer primary, L-G fault on phase 2 of primary terminals

```
UNBALANCES TO BE APPLIED:

LINE TO GROUND FAULT AT BUS      4   PHASE 1
  L-G Z =    0.0000E+00   0.0000E+00

LINE TO GROUND FAULT AT BUS      2     PHASE 2
  L-G Z =    0.0000E+00   0.3000

ONE PHASE CLOSED BETWEEN BUSES      1   AND   2
  PHASE 2  Z =    0.0000E+00  -0.1000

ENTER 1 IF OK, 0 TO RE-SPECIFY UNBALANCES, -1 TO EXIT ACTIVITY: 1

              SEQUENCE THEVENIN IMPEDANCES AT FAULTED BUSES:

  BUS   NAME  BSKV          ZERO               POSITIVE              NEGATIVE
   4                 0.00000  0.10000     0.00000  0.25000     0.00000  0.25000
   2                 0.00000  0.15000     0.00000  0.15000     0.00000  0.15000
   1                 0.00000  0.05000     0.00000  0.05000     0.00000  0.05000
```

No singularity this time

```
LINE TO GROUND FAULT AT BUS      4:

SEQUENCE           /V0/     AN(V0)      /V+/     AN(V+)      /V-/     AN(V-)
PHASE              /VA/     AN(VA)      /VB/     AN(VB)      /VC/     AN(VC)

    4  (P.U.)     0.1667    150.00     0.2500    -30.00     0.0833    150.00
                  0.0000      0.00     0.3819   -160.89     0.3819    100.89

SEQUENCE           /I0/     AN(I0)      /I+/     AN(I+)      /I-/     AN(I-)
PHASE              /IA/     AN(IA)      /IB/     AN(IB)      /IC/     AN(IC)

FROM      3 1     1.6667   -120.00     1.6667   -120.00     1.6667   -120.00
                  5.0000   -120.00     0.0000      0.00     0.0000      0.00
```

Fault current is unchanged

```
LINE TO GROUND FAULT AT BUS      2:

SEQUENCE           /V0/     AN(V0)      /V+/     AN(V+)      /V-/     AN(V-)
PHASE              /VA/     AN(VA)      /VB/     AN(VB)      /VC/     AN(VC)

    2  (P.U.)     0.3333     60.00     0.4167      0.00     0.0833    -60.00
                  0.6614     19.11     0.0000      0.00     0.6614    100.89
```

Zero voltage at bus 2, phase 2, phases 1 and 3 a unchanged

```
SEQUENCE           /I0/     AN(I0)      /I+/     AN(I+)      /I-/     AN(I-)
PHASE              /IA/     AN(IA)      /IB/     AN(IB)      /IC/     AN(IC)

FROM      1       3.3333    -30.00     3.3333     90.00     3.3333   -150.00
                  0.0000      0.00    10.0000    -30.00     0.0000      0.00

FROM      1 1     3.3333    150.00     5.0000    -90.00     1.6667     30.00
                  2.8867   -120.00    10.0000    150.00     2.8867     60.00

FROM      3 1     0.0000      0.00     1.6667     90.00     1.6667     30.00
                  2.8868     60.00     0.0000      0.00     2.8867   -120.00
```

10 per-unit curre in closed phase cancels out leaving primary currents unchanged

Figure 11.77. Solution for Case of Figure 11.74, "Combined Transformer Faults Illustrating Possibility of Singular Fault Constraint"(c)

11.7. Special Positive-Sequence Equivalents

Activities SCMU and ASCC are based on the assumption that the phase self- and mutual-impedances of each branch are balanced. Several situations exist, especially in dynamics, where the user will want to simulate a situation in which unbalance of the phase impedances and phase-to-phase coupling is a key effect. Activity SPCB was designed to calculate positive-sequence equivalents for these cases. Activity SPCB constructs positive-sequence equivalents for the following situations:

1. One open phase either grounded or not.

2. Two open phases.

3. Mid-line, line-ground, line-line-ground, or three-phase fault.

4. One breaker open.

A series of situations where this activity would be used is shown in Figure 11.78, “Situations in which SPCB Would be Used”. In this series, a line-ground fault 40% of the way down the line from bus 151, is assumed. The user, in a stability study, may then want to simulate the results of a stuck breaker. Finally, the user would want to see if stability was maintained when another breaker finally opens the faulted phase. The dialog to obtain the positive-sequence equivalents is shown in Figure 11.79, “Dialog for Using Activity SPCB (Sheet 1 of 3)”. In Figure 11.82, “Initial Line Data”, the pre unbalance line impedances and shunts are shown. The output of activity SPCB is displayed in Figure 11.83, “Pi Equivalent for Line-Ground Fault 40% Down Line From Bus 151” and, in Figure 11.84, “Stability Case Dialog for Mid-Line Fault”, the dialog used in a stability run to model the line-ground fault is shown.

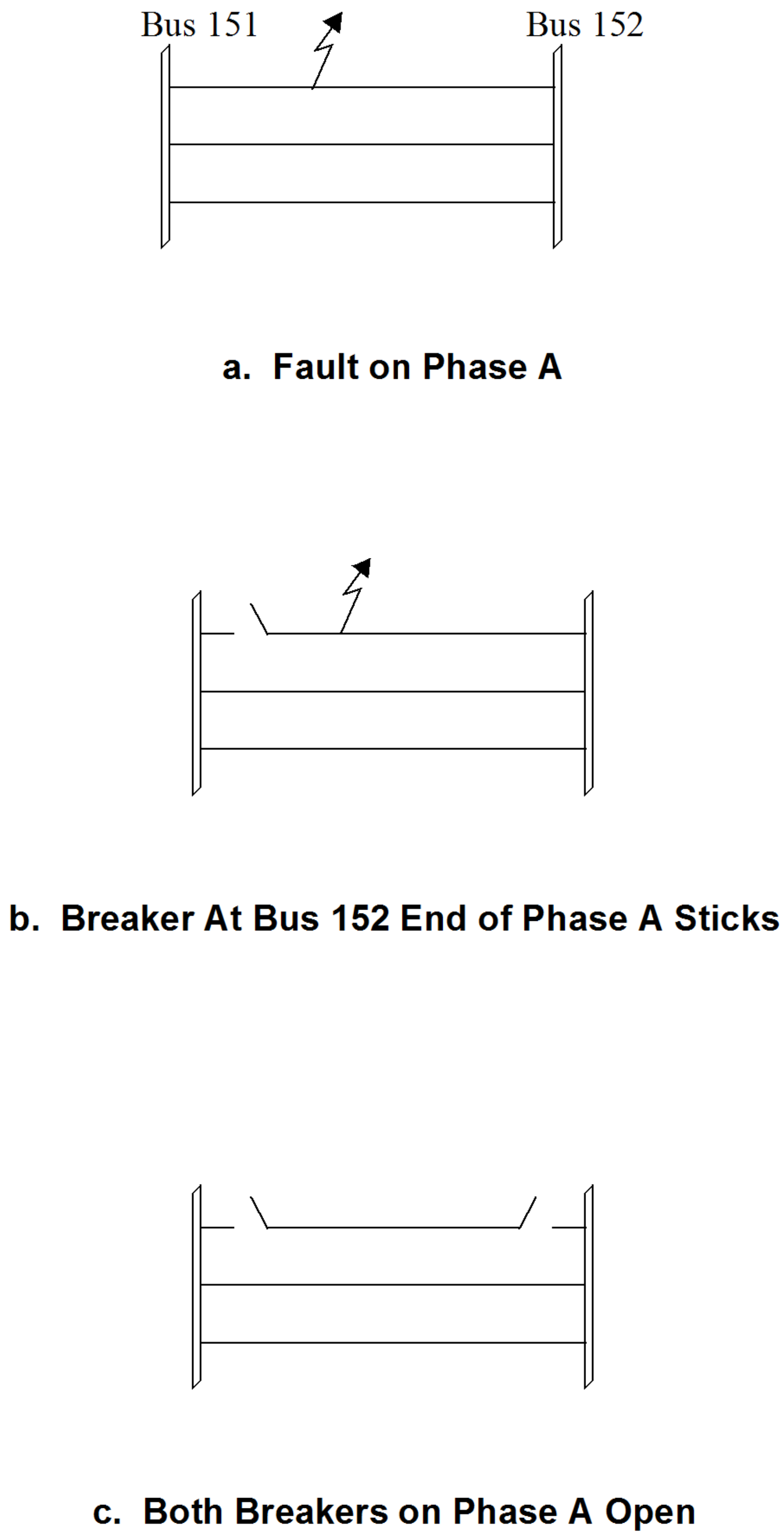


Figure 11.78. Situations in which SPCB Would be Used

```
ACTIVITY? CASE SAVNW                    Pick up case that includes sequence data
PSS®E PROGRAM APPLICATION GUIDE EXAMPLE
BASE CASE INCLUDING SEQUENCE DATA

CASE SAVNW.SAV WAS SAVED ON THU, APR 19 1990  12:00

ACTIVITY? FNSL                          Make sure it is solved
ORDERING NETWORK
DIAGONALS =     19   OFF-DIAGONALS =     34  MAX SIZE =    50

ENTER ITERATION NUMBER FOR VAR LIMITS
 0 FOR IMMEDIATELY, -1 TO IGNORE COMPLETELY: 0
ITER    DELTAP    BUS      DELTAQ    BUS       DELTA/V/    BUS    DELTAANG    BUS
  0     0.0002(  202)     0.0025(  205)      0.00001(  205)    0.00000(  102)
  1     0.0000(  151)     0.0000( 3005)
REACHED TOLERANCE IN   1 ITERATIONS

LARGEST MISMATCH:     0.00 MW     0.00 MVAR      0.00 MVA-BUS    152 [MID500    500]
SYSTEM TOTAL ABSOLUTE MISMATCH:                  0.02 MVA

ACTIVITY? CHNG

ENTER CHANGE CODE:
 0 = EXIT ACTIVITY                  1 = BUS DATA
 2 = GENERATOR DATA                 3 = BRANCH DATA
 4 = TRANSFORMER DATA               5 = AREA INTERCHANGE DATA
 6 = TWO-TERMINAL DC LINE DATA      7 = SOLUTION PARAMETERS
 8 = CASE HEADING                   9 = SWITCHED SHUNT DATA
10 = IMPEDANCE CORRECTION TABLES   11 = MULTI-TERMINAL DC DATA
12 = ZONE DATA: 3

ENTER FROM BUS, TO BUS, CIRCUIT IDENTIFIER
 (FROM BUS = 0 FOR NEW CHANGE CODE, -1 TO EXIT): 151 152

BRANCH DATA FOR CIRCUIT 1  FROM    151 [NUCPANT  500] TO    152 [MID500    500]:
 STATUS     LINE R     LINE X   CHARGING   RATE-A   RATE-B   RATE-C
OLD   1   0.00260   0.04600   3.50000   1200.0     0.0      0.0 CHANGE IT? 1   Branch must
ENTER STATUS, R, X, CHARGING, RATE-A, RATE-B, RATE-C, # OF CIRCUITS              be out-of-
0                                                                                 service
NEW   0   0.00260   0.04600   3.50000   1200.0     0.0      0.0

LINE SHUNTS: BUS    151 [NUCPANT  500]  BUS   152 [MID500    500]
OLD                  0.00000   0.00000         0.00000   0.00000 CHANGE IT? 0

ENTER CHANGE CODE:
 0 = EXIT ACTIVITY                  1 = BUS DATA
 2 = GENERATOR DATA                 3 = BRANCH DATA
 4 = TRANSFORMER DATA               5 = AREA INTERCHANGE DATA
 6 = TWO-TERMINAL DC LINE DATA      7 = SOLUTION PARAMETERS
 8 = CASE HEADING                   9 = SWITCHED SHUNT DATA
10 = IMPEDANCE CORRECTION TABLES   11 = MULTI-TERMINAL DC DATA
12 = ZONE DATA: 0

ACTIVITY? SEQD                                                   All three sequences
DIAGONALS =     20   OFF-DIAGONALS =     38  MAX SIZE =    54    must be factorized
POS. SEQUENCE: DIAGONALS =     20  OFF-DIAGONALS =     38
DIAGONALS =     20   OFF-DIAGONALS =     35  MAX SIZE =    48
BUS    101 [NUC-A     21.6] ISOLATED IN ZERO SEQUENCE
BUS    102 [NUC-B     21.6] ISOLATED IN ZERO SEQUENCE
BUS    206 [URBGEN    18.0] ISOLATED IN ZERO SEQUENCE
ZERO SEQUENCE: DIAGONALS =     20  OFF-DIAGONALS =     35

ACTIVITY? SPCB                                                  Run activity SPCB

ENTER OUTPUT DEVICE CODE:
 0 FOR NO OUTPUT     1 FOR CRT TERMINAL
 2 FOR A FILE        3 FOR KMW_UP
 4 FOR QMS_LG        5 FOR HARD COPY TERMINAL
 6 FOR ALTERNATE SPOOL DEVICE: 1
```

Figure 11.79. Dialog for Using Activity SPCB (Sheet 1 of 3)

```
ENTER FROM BUS, TO BUS NUMBERS OF BRANCH WITH UNBALANCE: 151 152

ZERO SEQUENCE THEVENIN IMPEDANCE SUBMATRIX:
  BUS         151 [NUCPANT  500]          152 [MID500    500]
  151   (    0.00003,    0.00471)   (    0.00007,    0.00202)
  152   (    0.00007,    0.00202)   (    0.00360,    0.03682)

POS. SEQUENCE THEVENIN IMPEDANCE SUBMATRIX:
  BUS         151 [NUCPANT  500]          152 [MID500    500]
  151   (    0.00233,    0.01588)   (    0.00333,    0.00848)
  152   (    0.00333,    0.00848)   (    0.00629,    0.01780)

NEG. SEQUENCE THEVENIN IMPEDANCE SUBMATRIX:
  BUS         151 [NUCPANT  500]          152 [MID500    500]
  151   (    0.00233,    0.01588)   (    0.00333,    0.00848)
  152   (    0.00333,    0.00848)   (    0.00629,    0.01780)

FROM BUS    151 [NUCPANT  500] TO BUS    152 [MID500    500]
ENTER CIRCUIT ID OR -1 TO EXIT ACTIVITY: 1

ENTER UNBALANCE CODE:
  0 TO EXIT                  1 FOR ONE PHASE OPEN
  2 FOR TWO PHASES OPEN      3 FOR IN-LINE FAULT
  4 FOR ONE BREAKER OPEN     5 FOR NO UNBALANCE: 3

ENTER TYPE OF FAULT:
 1 FOR LINE-GROUND     2 FOR LINE-LINE-GROUND
 3 FOR THREE PHASE: 1

ENTER IMPEDANCE TO GROUND (R,X): 0. 0.
ENTER FAULT LOCATION AS FRACTION OF LINE FROM BUS   151 [NUCPANT  500]: .4

PI EQUIVALENT Y MATRIX IS:
(      1.7221,    -24.8373)    (     -0.8931,     18.3901)
(     -0.8931,     18.3901)    (      1.4458,    -22.1050)

TO SIMULATE:

ONE PHASE GROUNDED WITH IMPEDANCE=      0.0000 +J      0.0000
  40.0 PERCENT OF WAY DOWN LINE FROM   151 [NUCPANT  500]

FOR BRANCH FROM BUS   151 [NUCPANT  500] TO BUS   152 [MID500    500] CIRCUIT 1
 USE EQUIVALENT R+JX= (     0.00263,     0.05425)  B= 0.0

AT BUS    151 [NUCPANT  500] USE LINE CONNECTED SHUNT= (    0.82907,    -6.44712)

AT BUS    152 [MID500    500] USE LINE CONNECTED SHUNT= (    0.55273,    -3.71482)

ENTER UNBALANCE CODE:
  0 TO EXIT                  1 FOR ONE PHASE OPEN
  2 FOR TWO PHASES OPEN      3 FOR IN-LINE FAULT
  4 FOR ONE BREAKER OPEN     5 FOR NO UNBALANCE: 4

ENTER 1 TO INCLUDE A PATH TO GROUND: 1
ENTER IMPEDANCE TO GROUND (R,X): 0. 0.

ENTER FAULT LOCATION AS FRACTION OF LINE FROM BUS   151 [NUCPANT  500]: .4

ENTER 1 IF BREAKER AT BUS   151 [NUCPANT  500] IS OPEN: 1

PI EQUIVALENT Y MATRIX IS:
(      0.6770,    -10.3099)    (     -0.7206,     13.8591)
(     -0.7218,     13.8661)    (      1.4410,    -20.7085)
```

Unbalance is between bus 151 and bus 152

Circuit 1

Mid-line fault

Line ground

40% down line

In stability, user should change impedance to 0.00263 + j0.05425 and set B to 0.0

These line shunts should be applied

Open breaker now

Figure 11.80. Dialog for Using Activity SPCB (Sheet 2 of 3)

```
TO SIMULATE:

BREAKER ON ONE PHASE OPEN AT BUS   151 [NUCPANT  500] END
THE PHASE IS
 GROUNDED WITH IMPEDANCE=       0.0000 +J       0.0000
  40.0 PERCENT OF WAY DOWN LINE FROM   151 [NUCPANT  500]

FOR BRANCH FROM BUS   151 [NUCPANT  500] TO BUS   152 [MID500   500] CIRCUIT 1
 USE EQUIVALENT R+JX= (    0.00374,     0.07194)  B= 0.0

AT BUS   151 [NUCPANT  500] USE LINE CONNECTED SHUNT= (   -0.04416,     3.55270)

AT BUS   152 [MID500   500] USE LINE CONNECTED SHUNT= (    0.71979,    -6.84593)
```

Equivalent pi for unbalance

```
ENTER UNBALANCE CODE:
  0 TO EXIT                1 FOR ONE PHASE OPEN
  2 FOR TWO PHASES OPEN    3 FOR IN-LINE FAULT
  4 FOR ONE BREAKER OPEN   5 FOR NO UNBALANCE: 1
```

Now open phase, assume fault immediately extinguishes (no ground path)

```
ENTER 1 TO INCLUDE A PATH TO GROUND: 0

PI EQUIVALENT Y MATRIX IS:
(      0.7162,     -9.6430)    (     -0.6977,     11.0660)
(     -0.6976,     11.0639)    (      0.6846,     -9.8205)

TO SIMULATE:

ONE PHASE OPEN

FOR BRANCH FROM BUS   151 [NUCPANT  500] TO BUS   152 [MID500   500] CIRCUIT 1
 USE EQUIVALENT R+JX= (    0.00568,     0.09002)  B= 0.0

AT BUS   151 [NUCPANT  500] USE LINE CONNECTED SHUNT= (    0.01859,     1.42191)

AT BUS   152 [MID500   500] USE LINE CONNECTED SHUNT= (   -0.01305,     1.24439)
```

Equivalent pi

```
ENTER UNBALANCE CODE:
  0 TO EXIT                1 FOR ONE PHASE OPEN
  2 FOR TWO PHASES OPEN    3 FOR IN-LINE FAULT
  4 FOR ONE BREAKER OPEN   5 FOR NO UNBALANCE:
```

Figure 11.81. Dialog for Using Activity SPCB (Sheet 3 of 3)

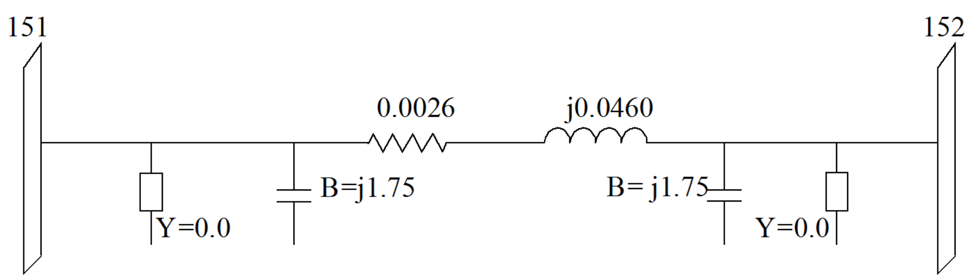


Figure 11.82. Initial Line Data

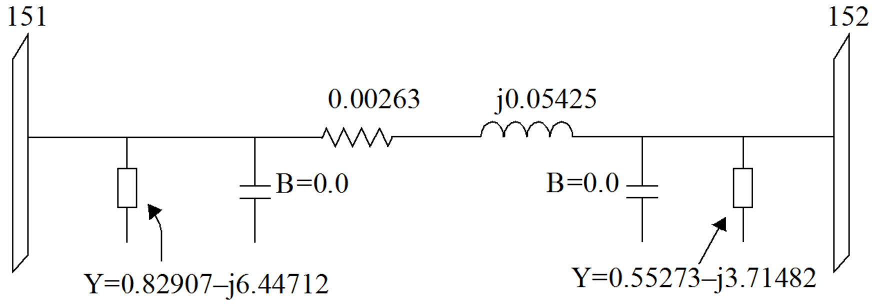


Figure 11.83. Pi Equivalent for Line-Ground Fault 40% Down Line From Bus 151

```
ACTIVITY? ALTR

PSS®E PROGRAM APPLICATION GUIDE EXAMPLE
BASE CASE INCLUDING SEQUENCE DATA

TIME = 0.0000

ENTER CHANGE CODE:
 0 = NO MORE CHANGES       1 = OUTPUT CHANNEL DATA
 2 = CONS                  3 = VARS
 4 = CRT PLOT CHANNELS     5 = ICONS
 6 = SOLUTION PARAMETERS   7 = STATES
 8 = CASE HEADING: 0

NETWORK DATA CHANGES (1=YES, 0=NO)? 1 <-------------- Yes, network changes
PICK UP NEW SAVED CASE (1=YES, 0=NO)? 0

ENTER CHANGE CODE:
 0 = EXIT ACTIVITY                  1 = BUS DATA
 2 = GENERATOR DATA                 3 = BRANCH DATA
 4 = TRANSFORMER DATA               5 = AREA INTERCHANGE DATA
 6 = TWO-TERMINAL DC LINE DATA      7 = SOLUTION PARAMETERS
 8 = CASE HEADING                   9 = SWITCHED SHUNT DATA
10 = IMPEDANCE CORRECTION TABLES   11 = MULTI-TERMINAL DC DATA
12 = ZONE DATA: 3 <------------------------------------------ Branch data

ENTER FROM BUS, TO BUS, CIRCUIT IDENTIFIER
 (FROM BUS = 0 FOR NEW CHANGE CODE, -1 TO EXIT): 151 152

BRANCH DATA FOR CIRCUIT 1  FROM   151 [NUCPANT  500] TO   152 [MID500   500]:  Change
 STATUS     LINE R     LINE X   CHARGING   RATE-A   RATE-B   RATE-C          impedance
OLD    1    0.00260    0.04600   3.50000   1200.0     0.0      0.0 CHANGE IT? 1 <--and set
ENTER STATUS, R, X, CHARGING, RATE-A, RATE-B, RATE-C, # OF CIRCUITS          net charging
, .00263, .05425, 0                                                          to zero
NEW    1    0.00263    0.05425   0.00000   1200.0     0.0      0.0

LINE SHUNTS: BUS    151 [NUCPANT   500]   BUS    152 [MID500    500]          Change
OLD                 0.00000    0.00000         0.00000    0.00000 CHANGE IT? 1 <-- line shunt
ENTER FROM BUS SHUNT, TO BUS SHUNT: .82907 -6.44712 .55273 -3.71482           data
NEW                 0.82907   -6.44712         0.55273   -3.71482

METERED END IS BUS   151 [NUCPANT   500]. ENTER 1 TO REVERSE: 0

ENTER FROM BUS, TO BUS, CIRCUIT IDENTIFIER
 (FROM BUS = 0 FOR NEW CHANGE CODE, -1 TO EXIT): -1
   20 DIAGONAL AND     38 OFF-DIAGONAL ELEMENTS

ACTIVITY? RUN

AT TIME =   0.000 ENTER TPAUSE, NPRT, NPLT, CRTPLT: .1 10 1
CHANNEL OUTPUT FILE IS OUT1
   TIME   ANG1NUC-A      ANG1HYDRO      ANG1URBGEN     ANG1MINE       ANG1CATDOG
  0.000     60.386         30.609         26.895         13.609         22.090
            P 1NUC-A       P 1HYDRO       P 1URBGEN      P 1MINE        P 1CATDOG
    6       6.2454         4.9359         7.1353         2.1685         0.88180
            Q 1NUC-A       Q 1HYDRO       Q 1URBGEN      Q 1MINE        Q 1CATDOG
   11       3.5682         5.8957         7.4036         3.1673         0.94522
          ET 1NUC-A      ET 1HYDRO      ET 1URBGEN     ET 1MINE       ET 1CATDOG
   16       0.90982        0.91378        0.90918        0.98532        0.86420
          EFD1NUC-A      EFD1HYDRO      EFD1URBGEN     EFD1MINE       EFD1CATDOG
   21       2.2634         3.5011         2.5020         1.7653         3.0048
          SPD1NUC-A      SPD1HYDRO      SPD1URBGEN     SPD1MINE       SPD1CATDOG
   26      0.33719E-03    0.24060E-03    0.30415E-03    0.75357E-04    0.25129E-03
          PM 1NUC-A      PM 1HYDRO      PM 1URBGEN       V-HYDRO        V-SUB230
   31       0.83931        0.83710        0.81032        0.91378        0.84809
          M  201-   204  M  205-   154  R  201-   204  2
   36       509.97         496.68         0.16351        0.86086E-02
```

Figure 11.84. Stability Case Dialog for Mid-Line Fault

11.8. Two-Wire System Option

11.8.1. Introduction

PSS®E includes an option in activities SEQD, SCMU, SCOP, and ASCC to handle certain two- and one-phase systems. This option was implemented primarily to handle certain European electric traction systems having a primary transmission system of two phases at 180° displacement feeding a single-phase catenary system. The basic system connections in this system are shown in Figure 11.85, "Two-Phase System Configuration for Railway Application", but other two- and one-phase systems can be handled by the appropriate setup of the sequence network models.

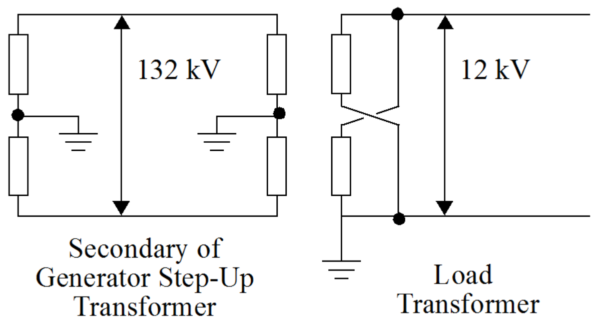


Figure 11.85. Two-Phase System Configuration for Railway Application

The two-phase system option is invoked by activity OPTN. The short circuit phase option allows the selection of two-phase instead of the conventional three-phase mode. Selecting the two-phase option has the following effects:

- The symmetrical component a operator becomes (−1+j0), and the negative sequence is ignored, giving

$$\begin{bmatrix} i_0 \\ i_1 \end{bmatrix} = 1/2 \begin{bmatrix} 1 & 1 \\ 1 & -1 \end{bmatrix} \begin{bmatrix} i_a \\ i_b \end{bmatrix}$$

- The base voltage is taken to be the line-to-line voltage at base conditions, and the base current is taken to be the corresponding line current so that

$$\text{L base} = \frac{MVA_{base}}{V_{LL\ base}}$$

$$Z_{LG\ base} = \frac{V^2_{LL\ base}}{2\ MVA_{base}}$$

- Line-to-ground voltages in kV are calculated as

  $V_{LG} = 0.5(V_{LL\ base} \times v_{pu})$

Phase currents in amperes are calculated as

$I_p = I_{L\ base} \times I_{pu}$

where v_{pu} and I_{pu} are the per-unit bus voltage and branch current, respectively.

Running PSS®E using the two-phase option is identical to its use in conventional three-phase mode except for the following:

1. Negative-sequence data may be entered for generators, branches, and loads but it is ignored in activities SEQD, SCMU, SCOP, and ASCC.
2. Unbalanced faults may involve only phases 1 and 3. (The excluded phase in an L-L-G fault must be phase 2.) The three-phase fault option of SCMU (option 7) must not be used.
3. The two-phases-closed fault (option 6) should not be used.

11.8.2. Two-Phase System Data

Transmission Lines

A two-phase two-conductor transmission line is characterized by positive- and zero-sequence impedances

$Z_1 = Z_p - Z_m$

$Z_0 = Z_p + Z_m$

where

Z_1 Positive-sequence impedance.

Z_0 Zero-sequence impedance.

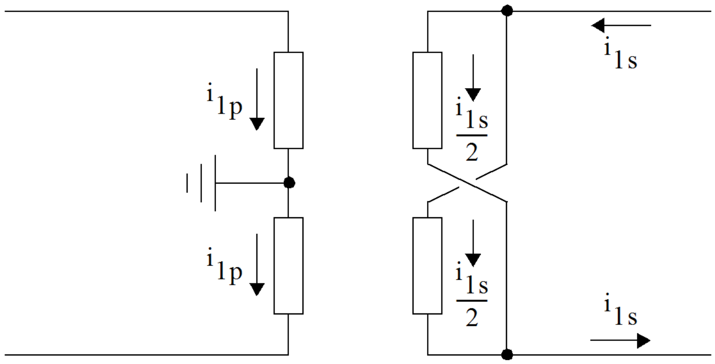
Z_p Self impedance of one phase conductor.

Z_m Mutual impedance between the phase conductors.

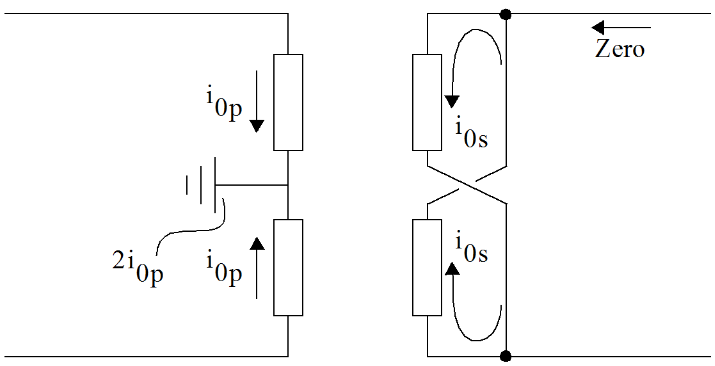
Similar expressions hold for the charging capacitances in the positive- and zero-sequences.

Transformers

The positive and zero-sequence characteristics of transformers must be determined from their internal connections. As an example, consider the transformer connection shown in Figure 11.85, “Two-Phase System Configuration for Railway Application”. The behavior of the transformer when positive and zero-sequence currents, respectively, flow in its primary windings are shown in Figure 11.86, “Behavior of Transformer with Secondary Windings Parallel to Single-Phase Load”. When positive-sequence current flows in the primary side, the two secondary windings are effectively in parallel and a positive-sequence current flows in the secondary leads. When a zero-sequence current flows in the primary leads, the direction of current is reversed in one primary and secondary winding. The two secondary windings now form a short-circuited loop; a current corresponding to the primary zero-sequence current flows around this loop, but no zero-sequence current flows in the secondary leads. The behavior of the primary and secondary currents in this transformer is not affected by the grounding of one secondary lead; no zero-sequence current can flow into the transformer because the ground is external to it.



a. Positive-Sequence Behavior



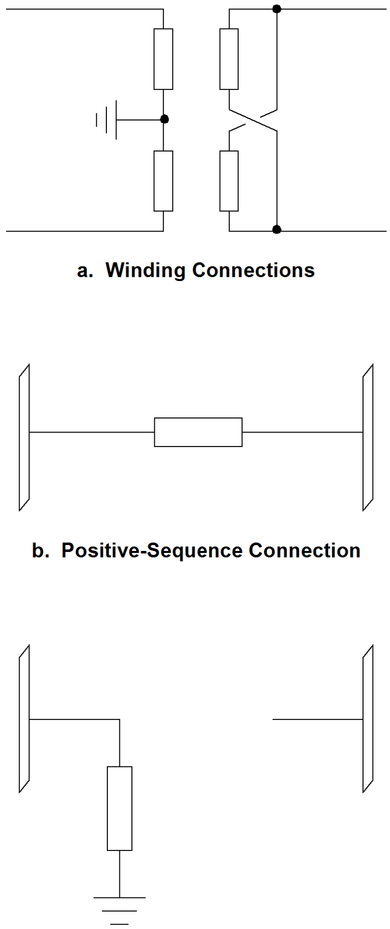
b. Zero-Sequence Behavior

Figure 11.86. Behavior of Transformer with Secondary Windings Parallel to Single-Phase Load

The modeling of the load transformer in PSS®E can be handled in a completely standard manner by the use of connection codes. The positive- and zero-sequence connections corresponding to Figure 11.85, "Two-Phase System Configuration for Railway Application" and Figure 11.86, "Behavior of Transformer with Secondary Windings Parallel to Single-Phase Load", are shown in Figure 11.87, "Sequence Connections Corresponding to Figure 11.86, "Behavior of Transformer with Secondary Windings Parallel to Single-Phase Load"". They may be specified to PSS®E by a winding connection code of 2 (no series path; ground path on the winding 1 side).

Secondary Circuits

The load on the secondary side of the transformer shown in Figure 11.85, "Two-Phase System Configuration for Railway Application" must be modeled according to its physical connections. Straightforward possibilities are shown in Figure 11.88, "Sequence Circuits for Loads on Two-Phase System". Grounding of one phase of a load does not create a zero-sequence path to ground. A ground must exist inside the load device in order for it to carry a zero-sequence current; such internal ground connections exist in the center-tapped load (Figure 11.88, "Sequence Circuits for Loads on Two-Phase System"a) and in the transmission line section (Figure 11.88, "Sequence Circuits for Loads on Two-Phase System"d) as a result of its shunt charging capacitances.

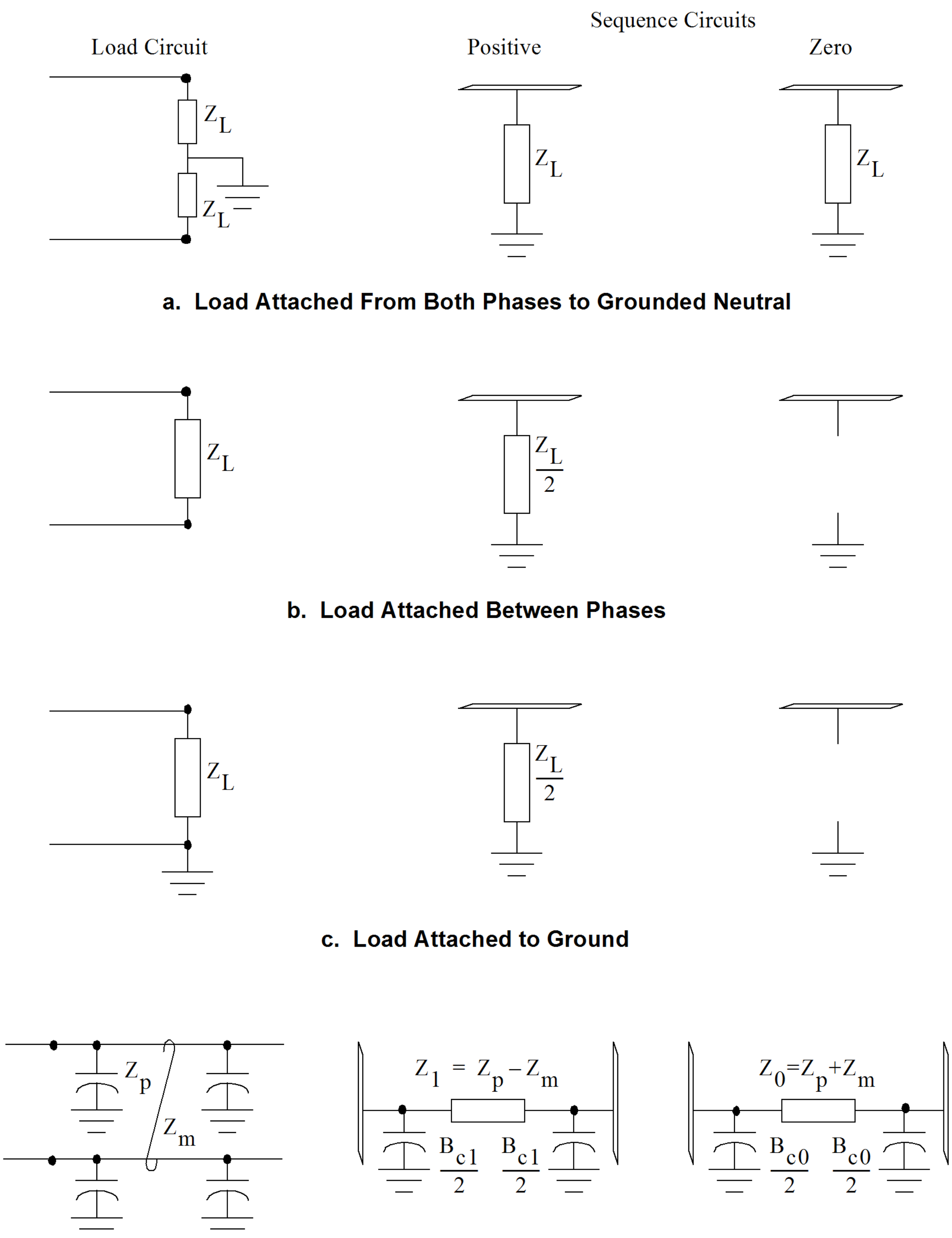


a. Winding Connections

b. Positive-Sequence Connection

c. Zero-Sequence Connection

Figure 11.87. Sequence Connections Corresponding to Figure 11.86, “Behavior of Transformer with Secondary Windings Parallel to Single-Phase Load”



a. Load Attached From Both Phases to Grounded Neutral

b. Load Attached Between Phases

c. Load Attached to Ground

d. Mutual Coupling

Figure 11.88. Sequence Circuits for Loads on Two-Phase System

Faults

Faults on the two phase system may be represented by the standard PSS®E repertoire, except that the three-phase and single-phase-open faults must not be used. The two phase system consists of phases a and c. Hence an L-G fault must be on phase a or c, and an L-L-G fault must exclude phase b.

11.8.3. Example

Figure 11.89, "Sample System for Two-Phase Example Calculations" shows a small sample system for use in two-phase fault analysis examples. The system data are summarized in Figure 11.90, "Raw Data Files for Two-Phase System" and Figure 11.91, "Data Listings for Two-Phase System".

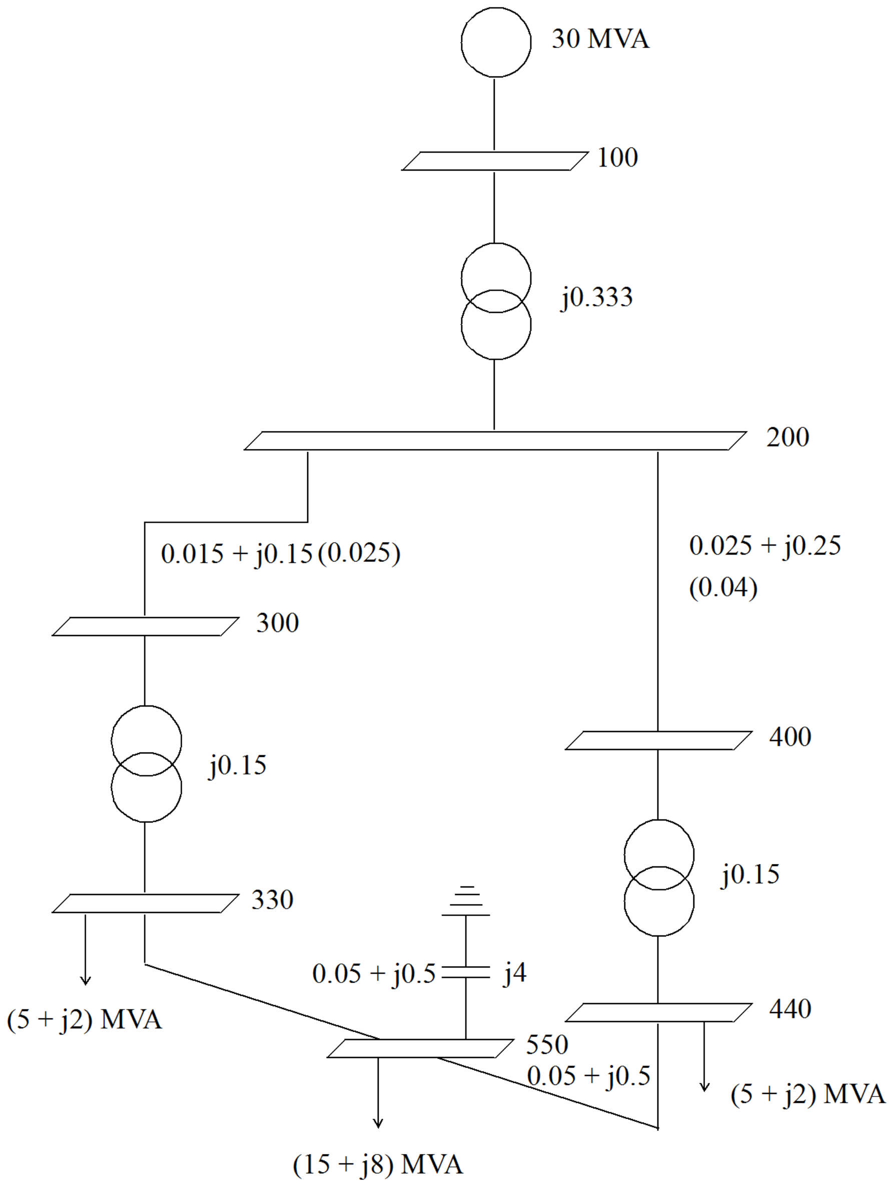


Figure 11.89. Sample System for Two-Phase Example Calculations

```
0 100
SMALL TWO PHASE EXAMPLE
SYSTEM FOR PROGRAM APPLICATION GUIDE
100   3    0    0    0      0      1     1     0   'GEN-1'     10
200   1    0    0    0      0      1     1     0   'HYDRO'    132
300   1    0    0    0      0      1     1     0   'WEST'     132
400   1    0    0    0      0      1     1     0   'EAST'     132
330   1    5    2    0      0      1     1     0   'EAST-LOD'   12
440   1    5    2    0      0      1     1     0   'WEST-LOD'   12
550   1   15    8    0      4      1     1     0   'MAIN-LOD'   12
0
100 3    0    0    20   0    1   200     30      0   .2   0    0   1     1     1
0
200 100   1   0    .33  0     35.      35.      35.        1.
200 300   1 .015  .15  .025  40        40.      40.
200 400   1 .025  .25  .04   40        40.      40.
330 300   1   0    .15   0    20        20.      20.        1.
440 400   1   0    .15   0    20        20.      20.        1.
330 550   1 .05   .5    0    15        15.      15.
440 550   1 .05   .5    0    15        15.      15.
0
200 100 1     200      1.15   .85  1.03       1.01     .00625    0
330 300 1     330      1.15   .85   1.0        .98     .00625    0
440 400 1     440      1.15   .85   1.0        .98     .00625    0
0
0
0
0
0
0
0
0
```

a. Power Flow Raw Data

```
0
100    3     0       .2
0
0
100    3     0        0
0
0
0
200  100     1       0        .33
200  300     1      .02       .3     .04
200  400     1      .04       .45    .065
330  300     1      0         .15
440  400     1      0         .15
330  550     1      .04       .8
440  550     1      .04       .8
0
0
200  100    1      1      2
330  300    1      2      1
440  400    1      2      1
0
```

Connection codes to represent parallel-secondary transformer connections

b. Sequence Raw Data

Figure 11.90. Raw Data Files for Two-Phase System

```
     PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS®E      TUE, OCT 08 1991   14:46
SMALL TWO PHASE EXAMPLE                                                BUS DATA
SYSTEM FOR PROGRAM APPLICATION GUIDE
 BUS#    NAME   BSKV CODE    VOLT   ANGLE    PLOAD    QLOAD      S H U N T  AREA ZONE
  100 GEN-1     10.0    3  1.0000     0.0      0.0      0.0     0.0      0.0     1    1
  200 HYDRO      132    1  1.0164    -4.8      0.0      0.0     0.0      0.0     1    1
  300 WEST       132    1  1.0090    -5.9      0.0      0.0     0.0      0.0     1    1
  330 EAST-LOD12.0      1  0.9958    -7.0      5.0      2.0     0.0      0.0     1    1
  400 EAST       132    1  1.0069    -6.4      0.0      0.0     0.0      0.0     1    1
  440 WEST-LOD12.0      1  0.9942    -7.5      5.0      2.0     0.0      0.0     1    1
  550 MAIN-LOD12.0      1  0.9798    -9.4     15.0      8.0     0.0      4.0     1    1


 BUS#    NAME   BSKV COD MCNS PGEN    QGEN    QMAX    QMIN VSCHED   VACT. REMOT PCT Q
  100 GEN-1     10.0  3    1   25.1     5.4    20.0     0.0 1.0000 1.0164   200   1.0


 FROM     TO CKT NAME      NAME      LINE R   LINE X  CHRGING TP ST RATA RATB RATC
  100     200* 1  GEN-1     HYDRO     0.0000   0.3300   0.0000  T  1   35   35   35
  200*    300  1  HYDRO     WEST      0.0150   0.1500   0.0250     1   40   40   40
  200*    400  1  HYDRO     EAST      0.0250   0.2500   0.0400     1   40   40   40
  300     330* 1  WEST      EAST-LOD  0.0000   0.1500   0.0000  T  1   20   20   20
  330*    550  1  EAST-LOD MAIN-LOD   0.0500   0.5000   0.0000     1   15   15   15
  400     440* 1  EAST      WEST-LOD  0.0000   0.1500   0.0000  T  1   20   20   20
  440*    550  1  WEST-LOD MAIN-LOD   0.0500   0.5000   0.0000     1   15   15   15


 FROM    TO CKT TP RATIO  ANGLE RG CONT   RMAX    RMIN    VMAX    VMIN   STEP TAB
  100   200   1  T 1.0313   0.00 1    200 1.1500  0.8500  1.0300  1.0100 0.00625
  300   330   1  T 0.9937   0.00 1    330 1.1500  0.8500  1.0000  0.9800 0.00625
  400   440   1  T 0.9937   0.00 1    440 1.1500  0.8500  1.0000  0.9800 0.00625


X------ BUS -----X COD ZERO SEQ SHUNT NEG SEQ SHUNT POS SEQ SHUNT  PLOAD  QLOAD
  100 GEN-1    10.0  3   0.000   0.000  0.000  0.000  0.000  0.000  0.000  0.000
  200 HYDRO     132  1   0.000   0.000  0.000  0.000  0.000  0.000  0.000  0.000
  300 WEST      132  1   0.000   0.000  0.000  0.000  0.000  0.000  0.000  0.000
  330 EAST-LOD12.0   1   0.000   0.000  0.000  0.000  0.000  0.000  0.050  0.020
  400 EAST      132  1   0.000   0.000  0.000  0.000  0.000  0.000  0.000  0.000
  440 WEST-LOD12.0   1   0.000   0.000  0.000  0.000  0.000  0.000  0.050  0.020
  550 MAIN-LOD12.0   1   0.000   0.000  0.000  0.000  0.000  0.040  0.150  0.080

 BUS# ID    ZGEN (ZERO)     ZGEN (POS.)     ZGEN (NEG.) MBASE    X T R A N   GENTAP
  100  3 0.0000 0.0000   0.0000 0.2000   0.0000 0.2000     30 0.0000 0.0000 1.0000


 FROM     TO   CKT R, X, B (POS. AND NEG.)    R, X, B (ZERO SEQ.) STAT RATIO   ANGLE
  100U    200GT 1   0.0000  0.3300  0.0000  0.0000  0.3300  0.0000 1 1.0313
  200     300   1   0.0150  0.1500  0.0250  0.0200  0.3000  0.0400 1
  200     400   1   0.0250  0.2500  0.0400  0.0400  0.4500  0.0650 1
  300G    330UT 1   0.0000  0.1500  0.0000  0.0000  0.1500  0.0000 1 0.9937
  330     550   1   0.0500  0.5000  0.0000  0.0400  0.8000  0.0000 1
  400G    440UT 1   0.0000  0.1500  0.0000  0.0000  0.1500  0.0000 1 0.9937
  440     550   1   0.0500  0.5000  0.0000  0.0400  0.8000  0.0000 1
```

Capacitor bank not grounded internally

Connection codes reflect center tapped primary/parallel secondary transformer arrangements

Figure 11.91. Data Listings for Two-Phase System

The initial condition power flow solution is shown in Figure 11.92, “Initial Condition Power Flow Solution for Two-Phase Sample System”; this is exactly the same as for a three-phase system solution because it involves only balanced operation and the positive sequence. The bus voltages in kilovolts are line-to-line values. This solution was made with the following PSS®E option settings:

- 50 Hz base frequency.
- Two-phase solution mode.
- Polar output of fault analysis results.

```
     PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS®E      TUE, OCT 08 1991  14:58
SMALL TWO PHASE EXAMPLE                                                  RATING
SYSTEM FOR PROGRAM APPLICATION GUIDE                                      SET A

BUS    100 GEN-1    10.0 AREA CKT    MW     MVAR     MVA  %I 1.0000PU   0.00  100
 GENERATION                1        25.1     5.5R   25.7  86 10.000KV
 TO    200 HYDRO     132   1  1     25.1     5.5    25.7  73 1.0313UN

BUS    200 HYDRO     132 AREA CKT    MW     MVAR     MVA  %I 1.0162PU  -4.83  200
                           1                                 134.13KV
 TO    100 GEN-1    10.0   1  1    -25.1    -3.3    25.3  71 1.0313LK
 TO    300 WEST      132   1  1     13.3     2.5    13.5  33
 TO    400 EAST      132   1  1     11.8     0.8    11.9  29

BUS    300 WEST      132 AREA CKT    MW     MVAR     MVA  %I 1.0087PU  -5.91  300
                           1                                 133.15KV
 TO    200 HYDRO     132   1  1    -13.3    -4.8    14.1  35
 TO    330 EAST-LOD12.0    1  1     13.3     4.8    14.1  70 0.9937UN

BUS    330 EAST-LOD12.0 AREA CKT     MW     MVAR     MVA  %I 0.9955PU  -7.04  330
                           1                                 11.946KV
 TO LOAD-PQ                          5.0     2.0     5.4
 TO    300 WEST      132   1  1    -13.3    -4.5    14.0  70 0.9937LK
 TO    550 MAIN-LOD12.0    1  1      8.3     2.5     8.6  58

BUS    400 EAST      132 AREA CKT    MW     MVAR     MVA  %I 1.0066PU  -6.45  400
                           1                                 132.88KV
 TO    200 HYDRO     132   1  1    -11.8    -4.5    12.6  31
 TO    440 WEST-LOD12.0    1  1     11.8     4.5    12.6  63 0.9937UN

BUS    440 WEST-LOD12.0 AREA CKT     MW     MVAR     MVA  %I 0.9938PU  -7.45  440
                           1                                 11.926KV
 TO LOAD-PQ                          5.0     2.0     5.4
 TO    400 EAST      132   1  1    -11.8    -4.3    12.6  63 0.9937LK
 TO    550 MAIN-LOD12.0    1  1      6.8     2.3     7.2  48

BUS    550 MAIN-LOD12.0 AREA CKT     MW     MVAR     MVA  %I 0.9795PU  -9.39  550
                           1                                 11.754KV
 TO LOAD-PQ                         15.0     8.0    17.0
 TO SHUNT                            0.0    -3.8     3.8
 TO    330 EAST-LOD12.0    1  1     -8.2    -2.1     8.5  58
 TO    440 WEST-LOD12.0    1  1     -6.8    -2.0     7.1  48
```

Figure 11.92. Initial Condition Power Flow Solution for Two-Phase Sample System

Figure 11.93, "Output from Activity SCOP Corresponding to Figure 11.92, "Initial Condition Power Flow Solution for Two-Phase Sample System"" shows output from activity SCOP corresponding directly to Figure 11.92, "Initial Condition Power Flow Solution for Two-Phase Sample System", with no fault applied. In this report the negative sequence and b-phase fields have no significance. The a and c phase voltage fields show sequence and phase voltages on a line-to-ground basis. The current values are in terms of per unit line current.

Comparison of the flow into bus 550 from bus 330 in Figure 11.92, "Initial Condition Power Flow Solution for Two-Phase Sample System" and Figure 11.93, "Output from Activity SCOP Corresponding to Figure 11.92, "Initial Condition Power Flow Solution for Two-Phase Sample System"" shows:

Received MVA = 8.5

Receiving voltage = 0.9795 per unit = 11.754 kV (L-L) = 5.877 kV (L-G)

Phase current, I_p, from Figure 11.92, “Initial Condition Power Flow Solution for Two-Phase Sample System”, =

$$\frac{MVA}{V_{LL}} = \frac{8.5E6}{11.754E3} = 723.2A$$

Base phase current =

$$\frac{MVA_{base}}{V_{LL\ base}} = \frac{100E6}{12E3} = 8333.3\text{ A}$$

Per-unit phase current, from Figure 11.92, “Initial Condition Power Flow Solution for Two-Phase Sample System”, =

$$\frac{723.2}{8333.3} = 0.08605\text{ per unit}$$

Per-unit phase current, from Figure 11.93, “Output from Activity SCOP Corresponding to Figure 11.92, “Initial Condition Power Flow Solution for Two-Phase Sample System””, = 0.0867 per unit

Rerunning activity POUT with the kVA output option in effect shows that bus 550 receives 8496.5 kVA from bus 330. Redoing the above calculations gives the per-unit current as

$$\frac{8.4965E6}{11.754E3 \times 8333.3} = 0.08674\text{ per unit}$$

All transformers in the system are connected as shown in Figure 11.85, “Two-Phase System Configuration for Railway Application” with two low-voltage windings in parallel. This is reflected in the connection code data in Figure 11.90, “Raw Data Files for Two-Phase System” and Figure 11.91, “Data Listings for Two-Phase System”. The shunt capacitor bank at bus 550 is connected line-to-line and is not grounded internally.

Figure 11.94, “Simple L-G Fault at Bus 300” shows the output from activity SCMU for a single L-G fault applied at bus 300.

As expected, the a-phase bus voltage at the fault is zero, and a current of 1.6341 per unit flows into the fault, and at the fault $I_0 = I_1 = V_{oc} / Z_0 + Z_1$.

$$I_0 = I_1 = \frac{1.009}{0.00127 + j0.11696 + 0.28804 + j1.07742}$$

$$= 0.1933 - j0.798 = 0.8211 \angle{-76.4^o}$$

Figure 11.95, “Simple Ground Connection at Bus 330” shows the result of SCMU for an L-G fault at bus 330. Here, because no zero-sequence ground path exists in the secondary system except for the fault, there is no fault current, and no unbalance appears in the 132 kV primary system.

The ground connection at one point in the system does not affect the balanced load current at bus 330, and the fault current is zero. The a-phase voltage at bus 330 is zero, as expected. The c-phase voltage at bus 330 is listed by SCMU as 1.991 per unit. The phase voltages listed by SCMU are per-unit of phase-to-ground base voltage, and correspond to an a-phase-to-ground voltage of 1.991 × (12 / 2) = 11.95 kV.

```
SEQUENCE             /V0/      AN(V0)      /V+/      AN(V+)      /V-/      AN(V-)
PHASE                /VA/      AN(VA)      /VB/      AN(VB)      /VC/      AN(VC)

  550   (P.U.)      0.0000      0.00      0.9795     -9.39      0.0000      0.00
MAIN-LOD12.0        0.9795     -9.39      0.0000      0.00      0.9795    170.61

SEQUENCE             /I0/      AN(I0)      /I+/      AN(I+)      /I-/      AN(I-)
PHASE                /IA/      AN(IA)      /IB/      AN(IB)      /IC/      AN(IC)

TO    330   1       0.0000      0.00      0.0867    155.97      0.0000      0.00
EAST-LOD12.0        0.0867    155.97      0.0000      0.00      0.0867    -24.03

TO    440   1       0.0000      0.00      0.0722    154.05      0.0000      0.00
WEST-LOD12.0        0.0722    154.05      0.0000      0.00      0.0722    -25.95

SUM OF              0.0000      0.00      0.1589    -24.90      0.0000      0.00
CONTRIBUTIONS       0.1589    -24.90      0.0000      0.00      0.1589    155.10

SEQUENCE             /V0/      AN(V0)      /V+/      AN(V+)      /V-/      AN(V-)
PHASE                /VA/      AN(VA)      /VB/      AN(VB)      /VC/      AN(VC)

  330   (P.U.)      0.0000      0.00      0.9955     -7.04      0.0000      0.00
EAST-LOD12.0        0.9955     -7.04      0.0000      0.00      0.9955    172.96

SEQUENCE             /I0/      AN(I0)      /I+/      AN(I+)      /I-/      AN(I-)
PHASE                /IA/      AN(IA)      /IB/      AN(IB)      /IC/      AN(IC)

TO    300   1       0.0000      0.00      0.1407    154.13      0.0000      0.00
WEST       132      0.1407    154.13      0.0000      0.00      0.1407    -25.87

TO    550   1       0.0000      0.00      0.0867    -24.03      0.0000      0.00
MAIN-LOD12.0        0.0867    -24.03      0.0000      0.00      0.0867    155.97

SUM OF              0.0000      0.00      0.0541    -28.84      0.0000      0.00
CONTRIBUTIONS       0.0541    -28.84      0.0000      0.00      0.0541    151.16
```

Figure 11.93. Output from Activity SCOP Corresponding to Figure 11.92, "Initial Condition Power Flow Solution for Two-Phase Sample System"

```
LINE TO GROUND FAULT AT BUS   300 [WEST     132]   PHASE 1
  L-G Z =    0.0000E+00   0.0000E+00

              SEQUENCE THEVENIN IMPEDANCES AT FAULTED BUSES:

  BUS   NAME  BSKV          ZERO               POSITIVE             NEGATIVE
  300 WEST     132     0.00127  0.11696     0.28804  1.07742     0.00000  0.00000


LINE TO GROUND FAULT AT BUS   300 [WEST     132]:

SEQUENCE            /V0/     AN(V0)     /V+/     AN(V+)     /V-/     AN(V-)
PHASE               /VA/     AN(VA)     /VB/     AN(VB)     /VC/     AN(VC)

  300  (P.U.)      0.0960   -172.91    0.0960      7.09    0.0000      0.00
WEST     132       0.0000      0.00    0.0000      0.00    0.1920   -172.91

SEQUENCE            /I0/     AN(I0)     /I+/     AN(I+)     /I-/     AN(I-)
PHASE               /IA/     AN(IA)     /IB/     AN(IB)     /IC/     AN(IC)

FROM    200 1      0.1810    -80.09    0.7558    -80.88    0.0000      0.00   Load currents
HYDRO     132      0.9368    -80.73    0.0000      0.00    0.5749     98.87   flowing in
                                                                             c-phase
FROM    330 1      0.6400    -82.91    0.0679    -98.25    0.0000      0.00
EAST-LOD12.0       0.7057    -84.37    0.0000      0.00    0.5749    -81.13
                                     a-phase fault current contributions

SUM OF CONTRIBUTIONS INTO BUS   300 [WEST     132]:

  300              0.8208    -82.29    0.8208    -82.29    0.0000      0.00
WEST     132       1.6417    -82.29    0.0000      0.00    0.0000      0.00

CONTRIBUTIONS EQUIVALENT POSITIVE SEQUENCE ADMITTANCE    0.0927   -8.5492

                                                                    I0 = I1 for a-phase
FAULT CURRENT AT BUS   300 [WEST     132]:                          fault current

  300              0.8208    -82.29    0.8208    -82.29    0.0000      0.00
WEST     132       1.6417    -82.29    0.0000      0.00    0.0000      0.00   Fault current

POSITIVE SEQUENCE EQUIVALENT FAULT ADMITTANCE    0.0927   -8.5492
```

Figure 11.94. Simple L-G Fault at Bus 300

```
UNBALANCES APPLIED:

LINE TO GROUND FAULT AT BUS    330 [EAST-LOD12.0]    PHASE 1
  L-G Z =    0.0000E+00    0.0000E+00


              SEQUENCE THEVENIN IMPEDANCES AT FAULTED BUSES:

  BUS    NAME   BSKV         ZERO                POSITIVE             NEGATIVE
  330 EAST-LOD12.0   *****************    0.32217   1.14687       0.00000   0.00000

LINE TO GROUND FAULT AT BUS    330 [EAST-LOD12.0]:                    Zero voltage at point of
                                                                      ground on system
SEQUENCE             /V0/      AN(V0)     /V+/      AN(V+)     /V-/      AN(V-)
PHASE                /VA/      AN(VA)     /VB/      AN(VB)     /VC/      AN(VC)
                                                                                  Voltage on
  330   (P.U.)       0.9955    172.96     0.9955    -7.04      0.0000      0.00   ungrounded
EAST-LOD12.0         0.0000      0.00     0.0000     0.00      1.9910    172.96   phase is fully
                                                                                  offset
SEQUENCE             /I0/      AN(I0)     /I+/      AN(I+)     /I-/      AN(I-)
PHASE                /IA/      AN(IA)     /IB/      AN(IB)     /IC/      AN(IC)

FROM    300 1        0.0000      0.00     0.1407    -25.87     0.0000      0.00
WEST       132       0.1407    -25.87     0.0000      0.00     0.1407    154.13

FROM    550 1        0.0000      0.00     0.0867    155.97     0.0000      0.00
MAIN-LOD12.0         0.0867    155.97     0.0000      0.00     0.0867    -24.03


SUM OF CONTRIBUTIONS INTO BUS    330 [EAST-LOD12.0]:                            Ground does
                                                                                not affect
  330                0.0000      0.00     0.0541    -28.84     0.0000      0.00   balanced
EAST-LOD12.0         0.0541    -28.84     0.0000      0.00     0.0541    151.16   load cur-
                                                                                rent;
CONTRIBUTIONS EQUIVALENT POSITIVE SEQUENCE ADMITTANCE       0.0505    -0.0202   compare
                                                                                with
                                                 Fault current is zero
FAULT CURRENT AT BUS    330 [EAST-LOD12.0]:

  330                0.0000      0.00     0.0000      0.00     0.0000      0.00
EAST-LOD12.0         0.0000      0.00     0.0000      0.00     0.0000      0.00

POSITIVE SEQUENCE EQUIVALENT FAULT ADMITTANCE      0.0000      0.0000
```

Figure 11.95. Simple Ground Connection at Bus 330

Figure 11.96, "Secondary System Grounded at Buses 330 and 550" shows the results from SCMU when the a-phase of the 12-kV system is grounded (by an L-G fault) at both bus 330 and bus 550. In this case, the ungrounded zero-sequence network, as specified by the data in Figure 11.91, "Data Listings for Two-Phase System", cannot be handled by PSS®E because its admittance matrix is singular. This problem is rectified by connecting a low admittance branch (B = j0.01) to ground in the zero sequence at bus 330; this small shunt admittance is insignificant in relation to the admittances of the system branches, but is adequate to avoid the numerical problems stemming from the singular matrix.

Figure 11.97, "Current Flows (per unit) from Figure 11.96, "Secondary System Grounded at Buses 330 and 550"" shows the phase currents from Figure 11.96, "Secondary System Grounded at Buses 330 and 550" on the 2-line diagram of the secondary system. Note the following:

- The SUM OF CONTRIBUTIONS shown by SCMU for the a-phase includes both load and ground current.
- Current does flow on the a-phase conductor from bus 330 to 550 even though it is solidly grounded at both ends, as a result of the mutual coupling between the two phases of the line. No current would flow in

the a-phase conductor if the two phases were of isolated-phase construction and had no phase-to-phase mutual impedance.

Figure 11.98, “Secondary System Grounded at Buses 330 and 550 with L-G Fault at Bus 550” shows the output from SCMU for the system grounded as in Figure 11.96, “Secondary System Grounded at Buses 330 and 550” and Figure 11.97, “Current Flows (per unit) from Figure 11.96, “Secondary System Grounded at Buses 330 and 550””, and with a line-to-line fault at bus 550. Again, some current flows in the grounded a-phase conductor from bus 330 to bus 550.

```
LINE TO GROUND FAULT AT BUS    330 [EAST-LOD12.0]    PHASE 1
  L-G Z =    0.0000E+00    0.0000E+00

LINE TO GROUND FAULT AT BUS    550 [MAIN-LOD12.0]    PHASE 1
  L-G Z =    0.0000E+00    0.0000E+00

              SEQUENCE THEVENIN IMPEDANCES AT FAULTED BUSES:

  BUS   NAME   BSKV          ZERO              POSITIVE            NEGATIVE
  330 EAST-LOD12.0     0.00007*********    0.32217  1.14687    0.00000  0.00000
  550 MAIN-LOD12.0     0.04007-99.20067    0.42517  1.25624    0.00000  0.00000


SEQUENCE              /V0/     AN(V0)     /V+/     AN(V+)     /V-/     AN(V-)
PHASE                 /VA/     AN(VA)     /VB/     AN(VB)     /VC/     AN(VC)

  330   (P.U.)       1.0066    172.51    1.0066     -7.49    0.0000      0.00
EAST-LOD12.0         0.0000      0.00    0.0000      0.00    2.0132    172.51

SEQUENCE              /I0/     AN(I0)     /I+/     AN(I+)     /I-/     AN(I-)
PHASE                 /IA/     AN(IA)     /IB/     AN(IB)     /IC/     AN(IC)

FROM    300 1        0.0000      0.00    0.1517    -23.04    0.0000      0.00
WEST      132        0.1517    -23.04    0.0000      0.00    0.1517    156.96

FROM    550 1        0.0386    -26.93    0.0616    155.92    0.0000      0.00
MAIN-LOD12.0         0.0231    160.69    0.0000      0.00    0.1001    -25.18


SUM OF CONTRIBUTIONS INTO BUS    330 [EAST-LOD12.0]:

  330                0.0386    -26.93    0.0902    -22.33    0.0000      0.00
EAST-LOD12.0         0.1287    -23.71    0.0000      0.00    0.0518    161.10

CONTRIBUTIONS EQUIVALENT POSITIVE SEQUENCE ADMITTANCE     0.0866    -0.0229

LINE TO GROUND FAULT AT BUS    550 [MAIN-LOD12.0]:

SEQUENCE              /V0/     AN(V0)     /V+/     AN(V+)     /V-/     AN(V-)
PHASE                 /VA/     AN(VA)     /VB/     AN(VB)     /VC/     AN(VC)

  550   (P.U.)       0.9953    170.86    0.9953     -9.14    0.0000      0.00
MAIN-LOD12.0         0.0000      0.00    0.0000      0.00    1.9906    170.86

SEQUENCE              /I0/     AN(I0)     /I+/     AN(I+)     /I-/     AN(I-)
PHASE                 /IA/     AN(IA)     /IB/     AN(IB)     /IC/     AN(IC)

FROM    330 1        0.0386    153.07    0.0616    -24.08    0.0000      0.00
EAST-LOD12.0         0.0231    -19.31    0.0000      0.00    0.1001    154.82

FROM    440 1        0.0000      0.00    0.0614    -23.79    0.0000      0.00
WEST-LOD12.0         0.0614    -23.79    0.0000      0.00    0.0614    156.21


SUM OF CONTRIBUTIONS INTO BUS    550 [MAIN-LOD12.0]:

  550                0.0386    153.07    0.1229    -23.93    0.0000      0.00
MAIN-LOD12.0         0.0844    -22.56    0.0000      0.00    0.1615    155.35

CONTRIBUTIONS EQUIVALENT POSITIVE SEQUENCE ADMITTANCE     0.1194    -0.0315
```

Zero voltage at grounded point (bus 330)

Note current flow in a-phase conductor even though it is grounded at both ends

Load current (bus 330)

Zero voltage at grounded point (bus 550)

Algebraic sum of load and ground current

Load current (bus 550)

Figure 11.96. Secondary System Grounded at Buses 330 and 550

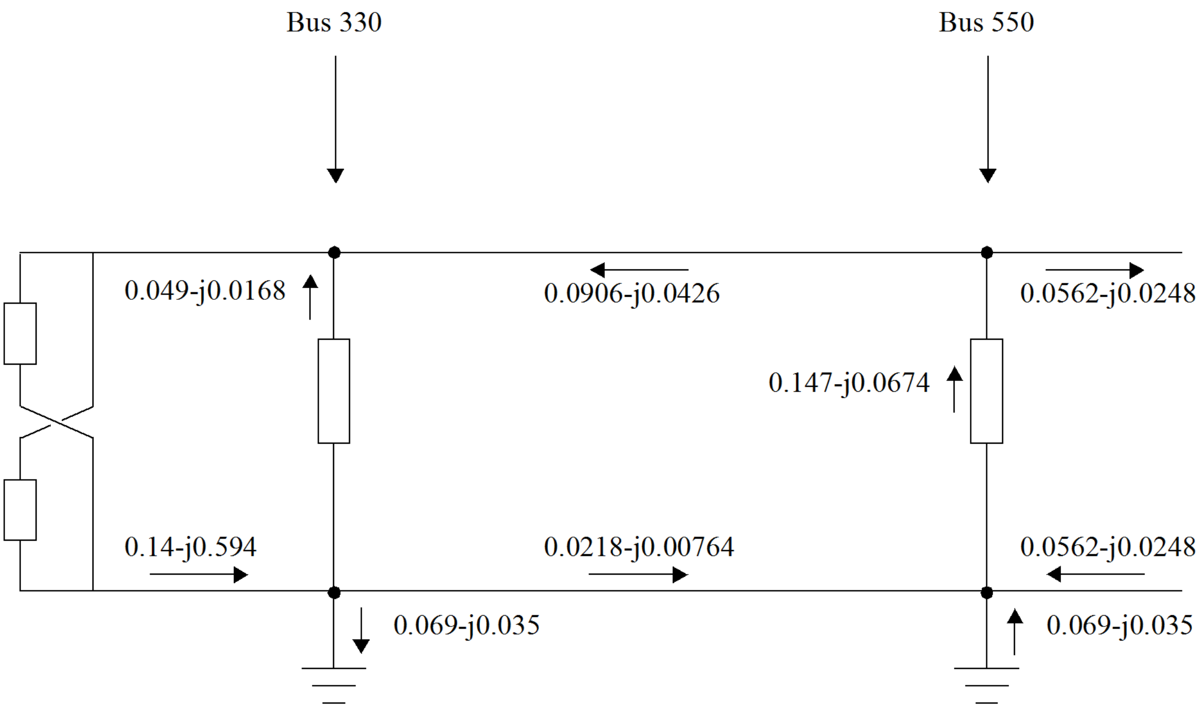


Figure 11.97. Current Flows (per unit) from Figure 11.96, "Secondary System Grounded at Buses 330 and 550"

```
LINE TO GROUND FAULT AT BUS    330 [EAST-LOD12.0]    PHASE 1
  L-G Z =    0.0000E+00    0.0000E+00

LINE TO GROUND FAULT AT BUS    550 [MAIN-LOD12.0]    PHASE 1
  L-G Z =    0.0000E+00    0.0000E+00

LINE TO LINE TO GROUND FAULT AT BUS    550 [MAIN-LOD12.0]    EXCLUDED PHASE 2
  L-L Z =    0.0000E+00    0.0000E+00    L-G Z =      9999.         9999.

              SEQUENCE THEVENIN IMPEDANCES AT FAULTED BUSES:

  BUS   NAME  BSKV          ZERO                POSITIVE            NEGATIVE
  330 EAST-LOD12.0    0.00007*********    0.32207   1.14707    0.00000   0.00000
  550 MAIN-LOD12.0    0.04007-99.20067    0.42504   1.25651    0.00000   0.00000

SEQUENCE             RE(V0)    IM(V0)    RE(V+)    IM(V+)    RE(V-)    IM(V-)
PHASE                RE(VA)    IM(VA)    RE(VB)    IM(VB)    RE(VC)    IM(VC)

  330   (P.U.)      -0.1420   -0.0107    0.1420    0.0107    0.0000    0.0000
EAST-LOD12.0         0.0000    0.0000    0.0000    0.0000   -0.2840   -0.0214

SEQUENCE             RE(I0)    IM(I0)    RE(I+)    IM(I+)    RE(I-)    IM(I-)
PHASE                RE(IA)    IM(IA)    RE(IB)    IM(IB)    RE(IC)    IM(IC)

FROM    300 1        0.0000    0.0000    0.0788   -0.4563    0.0000    0.0000
WEST      132        0.0788   -0.4563    0.0000    0.0000   -0.0788    0.4563

FROM    550 1        0.0222   -0.1764   -0.0494    0.2790    0.0000    0.0000
MAIN-LOD12.0        -0.0271    0.1027    0.0000    0.0000    0.0716   -0.4554


SEQUENCE             RE(V0)    IM(V0)    RE(V+)    IM(V+)    RE(V-)    IM(V-)
PHASE                RE(VA)    IM(VA)    RE(VB)    IM(VB)    RE(VC)    IM(VC)

  550   (P.U.)       0.0000    0.0000    0.0000    0.0000    0.0000    0.0000
MAIN-LOD12.0         0.0000    0.0000    0.0000    0.0000    0.0000    0.0000

SEQUENCE             RE(I0)    IM(I0)    RE(I+)    IM(I+)    RE(I-)    IM(I-)
PHASE                RE(IA)    IM(IA)    RE(IB)    IM(IB)    RE(IC)    IM(IC)

FROM    330 1       -0.0222    0.1764    0.0494   -0.2790    0.0000    0.0000
EAST-LOD12.0         0.0271   -0.1027    0.0000    0.0000   -0.0716    0.4554

FROM    440 1        0.0000    0.0000    0.0526   -0.3059    0.0000    0.0000
WEST-LOD12.0         0.0526   -0.3059    0.0000    0.0000   -0.0526    0.3059

SUM OF CONTRIBUTIONS INTO BUS    550 [MAIN-LOD12.0]:

  550              -0.0222    0.1764    0.1019   -0.5850    0.0000    0.0000
MAIN-LOD12.0        0.0797   -0.4086    0.0000    0.0000   -0.1241    0.7613
```

va = vc = 0 at fault

Current in grounded a-phase due to phase-to-phase mutual coupling

Sum of L-L fault current and ground current

L-L fault current

Figure 11.98. Secondary System Grounded at Buses 330 and 550 with L-G Fault at Bus 550

11.9. Calculation of Circuit Breaker Interrupting Duty

11.9.1. Introduction

The sudden application of a short-circuit fault to a power system produces currents where the transient form is shown in Figure 11.99, "Transient Phase Currents in Suddenly Applied Short Circuit". In the case of a three-phase fault (simultaneously applied in each phase), the total fault current in each phase consists of the following:

1. An alternating component that decays from an initial subtransient value to a final steady-state value.
2. A decaying unidirectional component where the initial amplitude is equal to the difference between the initial instantaneous value of the alternating component of fault current and the instantaneous current in the phase just prior to fault application.

Depending upon the standard (e.g., ANSI Standard C37.5 – 1975 or the International Electrotechnical Commission standards) the determination of circuit breaker duty requires the calculation of either of these values:

- The maximum instantaneous value of current in any phase at the instant, a few milliseconds after fault initiation, when the circuit breaker contacts separate.
- The root-mean-square (rms) value of current wave consisting of sinusoidal component of constant amplitude equal to the instantaneous amplitude of the decaying alternating component at an instant, superimposed on a constant unidirectional component of amplitude equal to that of the decaying unidirectional component at the same instant.

Figure 11.100, "Forms of Expression of Fault Current at Instant of Circuit Breaker Opening" illustrates the two current values of interest. The maximum instantaneous value, as shown in Figure 11.100, "Forms of Expression of Fault Current at Instant of Circuit Breaker Opening"a is of interest in connection with the IEC Circuit Breaker standards, while the rms value shown in Figure 11.100, "Forms of Expression of Fault Current at Instant of Circuit Breaker Opening"b is used by ANSI C37 standards. In this section, we describe the calculations made in PSS®E.

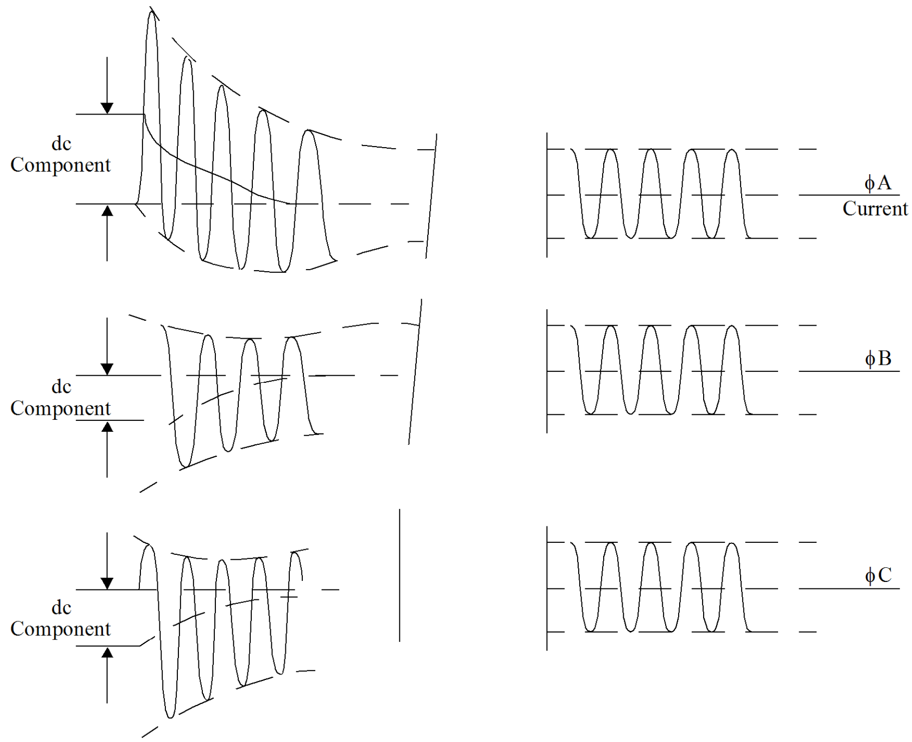


Figure 11.99. Transient Phase Currents in Suddenly Applied Short Circuit

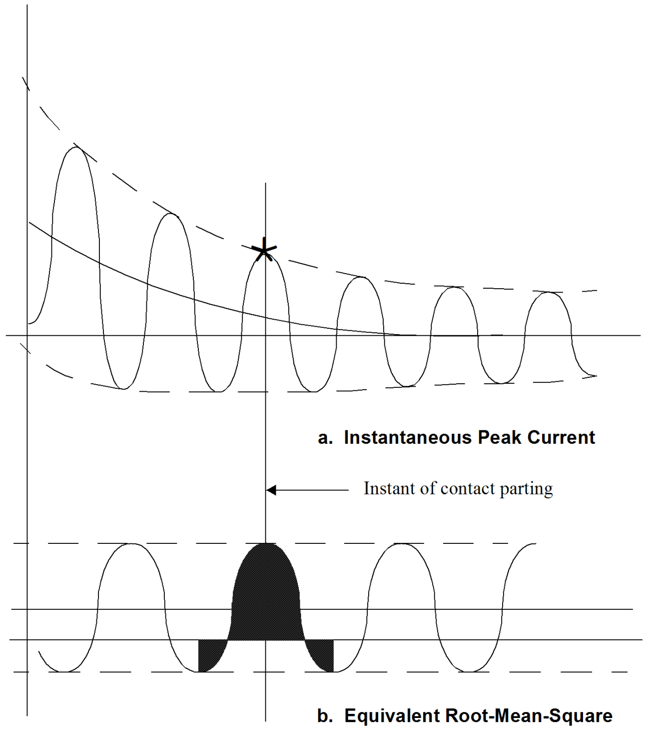


Figure 11.100. Forms of Expression of Fault Current at Instant of Circuit Breaker Opening

To determine these current amplitudes, the following data must be considered:

- The alternating current component results from *decaying* machine internal flux linkages behind *constant* subtransient impedances of the machines.
- The unidirectional component is, at the instant of fault application, determined by the value of the alternating component.

The alternating components can be approximated, with acceptable accuracy for several cycles after fault application, by expressing the generator flux as:

$$\Psi''_d = \Psi''_{do}(L''_d + L_e)\left[\left(\frac{1}{L_d + L_e}\right) + \left(\frac{1}{L'_d + L_e} - \frac{1}{L_d + L_e}\right)e^{-t/T'_{dz}}\right.$$
$$\left. + \left(\frac{1}{L''_d + L_e} - \frac{1}{L'_d + L_e}\right)e^{-t/T''_{dz}}\right]$$
$$+ i_{do}(L''_d + L_e)\left[\frac{L_d - L''_d}{L_d + L_e}(1 - e^{-t/T'_{dz}})\right.$$
$$\left. + \frac{L'_d - L''_d}{L'_d + L_e}(e^{-t/T'_{dz}} - e^{-t/T''_{dz}})\right]$$

and the equivalent for the q-axis. For induction motors ($L_d = L_q$ and $L'_d = L'_q$), the Ld terms are not in the above equations.

The calculations for initial fluxes, Ψ''_{do} and Ψ''_{qo}, and initial currents, i_{do} and i_{qo}, are based on the initial conditions in the power flow before fault application. The value of L_e at each generator is calculated by dividing the voltage at each terminal by the current flowing at the terminals at fault initiation. Because an initial loading on the machine, L_e, will never be infinity, this approximation will result in flux decaying even for very remote machines. The user is responsible for not including data for machines where flux decay is not wanted.

The initial value of the unidirectional component of fault current is, in the worst case, equal to the initial amplitude of the alternating component; this corresponds to a fully offset current wave as shown for Phase A in Figure 11.99, “Transient Phase Currents in Suddenly Applied Short Circuit”. Using full offset is, of course, conservative. The actual maximum offset depends on the fault point X/R and the point on the wave where the fault occurs. Thus, the peak is reached after some dc decay has occurred. The decay of the unidirectional component of fault current is given by:

$$i_{dc} = I_{ac}(0)\left[a_1 e^{-k_1 t} + a_2 e^{-k_2 t} + a_3 e^{-k_3 t} + \dots a_n e^{-k_n t}\right]$$

where $a_1 + a_2 + \dots + a_n = 1$

and

- The coefficients k_i, characterize the decay of the initial unidirectional components throughout the network.
- The coefficients, a_i, express the contribution of each decaying unidirectional current component to the unidirectional fault current.

In general, an exact expression of the unidirectional fault current would involve a number of *k* and a coefficients equal to the number of branches in the network. Their determination would require a calculation of the eigenvalues and eigenvectors of the differential equations

$[L_{net}]\,[sI_{net}] + [R_{net}]\,[i_{net}] = [0]$

where $[R_{net} + sL_{net}]$ is the operational impedance matrix of the complete network. This calculation is impractical for normal system analysis work, and it is usual to approximate the unidirectional fault current by

$$i_{dc} = I_{ac}(0)\, e^{-t/T_s} = L_{Thev} / R_{Thev}$$

where L_{Thev} and R_{Thev} are the Thevenin impedance (reactance, resistance) at the point of the fault.

11.9.2. Activity BKDY

Activity BKDY is a special short-circuit calculation activity. It determines the amplitude of the alternating and unidirectional (dc) components of current flowing in symmetrical faults and in the branches of the network. The alternating and dc components are calculated as indicated in Section 11.9.1, "Introduction" for the instant of fault application and for a specified time after the fault initiation. These component amplitudes are then used to determine the following:

- The maximum instantaneous current that could flow in any phase at the specified time after fault application, assuming that the fault was initiated at such a time, in relation to the voltage wave that the specified time after application corresponds to a current peak (Figure 11.100, "Forms of Expression of Fault Current at Instant of Circuit Breaker Opening").
- The rms value of the current at the specified time after fault application (Figure 11.100, "Forms of Expression of Fault Current at Instant of Circuit Breaker Opening").

The maximum instantaneous current, $I_{total\ peak}$, and rms currents, $I_{total\ rms}$, are determined by

$$I_{total\ peak} = I_{dc} + I_{ac}$$

$$I_{total\ rms} = \sqrt{I_{dc}^2 + I_{rms}^2}$$

where

I_{dc} Instantaneous amplitude of unidirectional component.

I_{ac} Peak amplitude of alternating component.

It is convenient to define an instantaneous rms value of the alternating current component, I_{rms}, by

$$I_{rms} = \frac{I_{ac}}{\sqrt{2}}$$

enabling the total rms current to be written as

$$I_{total\ rms} = \sqrt{I_{dc}^2 + I_{rms}^2}$$

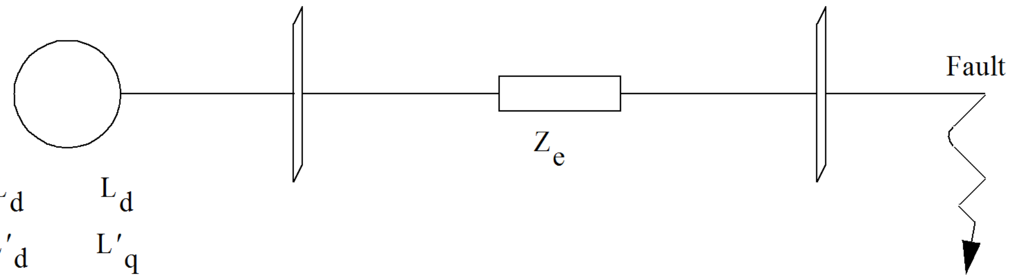
Activity BKDY starts with a load-flow case corresponding to system conditions just before the application of the fault. The values of the initial internal fluxes, Ψ''_{do}, Ψ''_{qo}, and initial currents, i_{do} and i_{qo}, are calculated from the prefault machine currents, terminal voltages, and the characteristic machine impedances, ZSORCE.

BKDY recognizes that the time constants T'_{dz}, T''_{dz}, T'_{qz}, T''_{qz} governing the decay of machine internal fluxes and currents are dependent on the relative values of the machine impedances and the impedances of the network between the machines and the fault. The relationships used to calculate these time constants are shown in Figure 11.101, "Relationships Between Machine Time Constants in Radial System". The L_e term is calculated at each machine in the network by dividing terminal voltage by terminal current at the instant the fault is applied.

If the fault location is close to major machines, it will present these machines with conditions approximating a short circuit at their terminals, $L_e = 0$. In this case the short-circuit time constants result. If the fault location is remote from key generators or fault impedances are high, open-circuit time constants result. Activity BKDY reads the machine reactances, open-circuit time constants, and short-circuit time constants, from a Breaker Duty File. The subtransient reactances specified in this file must correspond to the reactive parts of the impedances, ZSORCE, in the load-flow case. As data used by this activity is often the same as that used in dynamics, activity RWDY, which is available from dynamics, will create an input file for it.

Total dc offset current is calculated in two different manners by activity BKDY. For method one, the instantaneous dc offset for each branch is set equal to the magnitude of the difference between the prefault current on the branch and the instantaneous ac current after the fault. The total dc offset current is the magnitude of the sum of these differences. Decremented dc currents and hence total rms and total peak currents for each path are calculated by decaying each path's initial dc offset current by the Thevenin impedance at the point of the fault looking out each path.

Again the total dc offset current is the magnitude of the sum of the decayed currents, which have been stored and decayed as complex values. The values as calculated by method 1 are listed in the BKDY output on the line headed with FAULT CURRENT. For method two, the total instantaneous dc offset current is assumed to be equal to the total instantaneous ac current. This instantaneous dc offset current is decremented by the equivalent Thevenin impedance of all paths from the fault location. The total dc offset, total rms, and total peak current are listed following the Thevenin impedance and initial voltage on the line beginning with THEVENIN.



L_d	L_d
L'_d	L'_q
L''_d	L''_q
T'_{do}	T'_{do}
T''_{qo}	T''_{qo}

$$T'_{dz} = \frac{L'_d + L_e}{L_d + L_e} T'_{do} \qquad T'_{qz} = \frac{L'_q + L_e}{L_q + L_e} T'_{qo}$$

$$T''_{dz} = \frac{L''_d + L_e}{L'_d + L_e} T''_{do} \qquad T''_{qz} = \frac{L''_q + L_e}{L'_q + L_e} T''_{qo}$$

Figure 11.101. Relationships Between Machine Time Constants in Radial System

Figure 11.102, “Relationship of BKDY Outputs to Offset Fault Current Wave (amps)” shows sample outputs of activity BKDY, using polar coordinates and amperes for clarity. The upper block of output shows decremented values of current based on a contact parting delay time of zero; hence it describes the intersection of the envelope of the fully offset current wave with the t = 0+ axis. The ac component of current is stated in rms terms, the ratio of rms value to amplitude is 1.414, and the initial value of the dc (unidirectional) current component is 1.414 x 18569.7 = 26261.5 A. Also, with no decay taking place, the total peak current is twice the amplitude of the ac component.

The center block of output specifies the situation at 25 milliseconds (1.5 cycles) after fault initiation. Here the ac component of current has decayed to 16239.1 A, while the dc component has decayed more rapidly to 13996.6 A. The final output block, corresponding to 0.5 seconds with the dc component having decayed to essentially zero, shows the expected 1.414 relationship between rms and peak fault current, when expressed in amperes.

```
     PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS®E      WED, OCT 09 1991  14:57
PSS®E PROGRAM APPLICATION GUIDE EXAMPLE                          POLAR
BASE CASE INCLUDING SEQUENCE DATA                              COORDINATES
FAULT DUTY TIME IS  0.000 SECONDS - ALL BREAKERS

AT    154 [DOWNTN   230]   INITIAL RMS       DECREMENTED RMS     /DECREMENTED CURRENTS/
X----- FROM -----X CKT ALTERNATING CURNT  ALTERNATING CURNT PEAK DC  TOT RMS  TOT PEAK
  153 MID230    230 1    1921.4   -72.44    1921.4   -72.44  2124.4   2864.4    4841.6
  153 MID230    230 2    1601.1   -72.44    1601.1   -72.44  1759.5   2379.0    4023.9
  203 EAST230   230 1    1623.5   -74.96    1623.5   -74.96  1909.8   2506.7    4205.9
  205 SUB230    230 1   10775.9   -79.68   10775.9   -79.68 13851.1  17549.2   29090.6
 3008 CATDOG    230 1    2685.1   -84.00    2685.1   -84.00  3245.9   4212.5    7043.2
FAULT CURRENT  (AMPS)  18569.7   -78.52   18569.7   -78.52 22878.9  29466.6   49140.4
THEVENIN IMPEDANCE:     0.00078  0.01473 V: 0.9211     -7.68 26261.5  32163.6   52523.0
```

$\sqrt{2} \times 18569.7 = 26261.5A$

$\sqrt{(26261.5)^2 + \frac{(26261.5)^2}{2}}$

Different because of load on bus

$18569.7 \times \sqrt{2} + 26261.5$

$\sqrt{2} \times 16239.1 = 22965.6$

$\sqrt{(15918.6)^2 + \frac{(22965.6)^2}{2}}$

```
FAULT DUTY TIME IS  0.025 SECONDS - ALL BREAKERS

AT    154 [DOWNTN   230]   INITIAL RMS       DECREMENTED RMS     /DECREMENTED CURRENTS/
X----- FROM -----X CKT ALTERNATING CURNT  ALTERNATING CURNT PEAK DC  TOT RMS  TOT PEAK
  153 MID230    230 1    1921.4   -72.44    1699.5   -66.24  1144.2   2048.8    3547.7
  153 MID230    230 2    1601.1   -72.44    1416.2   -66.24   947.7   1704.1    2950.6
  203 EAST230   230 1    1623.5   -74.96    1439.0   -68.62  1268.5   1918.3    3303.5
  205 SUB230    230 1   10775.9   -79.68    9382.5   -71.93  9028.0  13020.7   22296.9
 3008 CATDOG    230 1    2685.1   -84.00    2337.7   -79.11  1614.9   2841.2    4920.9
FAULT CURRENT  (AMPS)  18569.7   -78.52   16239.1   -71.58 13996.6  21438.6   36962.2
THEVENIN IMPEDANCE:     0.00078  0.01473 V: 0.9211     -7.68 15918.6  22740.1   38884.2
```

Decaying total

Decaying each path independently

$22965.6 + 15918.6 = 38884.2$

```
FAULT DUTY TIME IS  0.500 SECONDS - ALL BREAKERS

AT    154 [DOWNTN   230]   INITIAL RMS       DECREMENTED RMS     /DECREMENTED CURRENTS/
X----- FROM -----X CKT ALTERNATING CURNT  ALTERNATING CURNT PEAK DC  TOT RMS  TOT PEAK
  153 MID230    230 1    1921.4   -72.44    1405.5   -51.12     0.0   1405.5    1987.7
  153 MID230    230 2    1601.1   -72.44    1171.3   -51.12     0.0   1171.3    1656.4
  203 EAST230   230 1    1623.5   -74.96    1192.7   -53.87     0.5   1192.7    1687.3
  205 SUB230    230 1   10775.9   -79.68    7513.8   -59.33     2.7   7513.8   10628.8
 3008 CATDOG    230 1    2685.1   -84.00    1887.5   -68.18     0.0   1887.5    2669.4
FAULT CURRENT  (AMPS)  18569.7   -78.52   13118.0   -58.49     3.2  13118.0   18554.8
THEVENIN IMPEDANCE:     0.00078  0.01473 V: 0.9211     -7.68     1.2  13118.0   18552.8
```

Figure 11.102. Relationship of BKDY Outputs to Offset Fault Current Wave (amps)

11.10. IEC Short Circuit Calculations

The short circuit currents in three phase ac systems are calculated in compliance with IEC 60909, 2001 standard.

11.10.1. Short Circuit Impedances of Electrical Equipment

The impedances of ac systems components are corrected as per IEC 60909-0 standard, Section 3.

Symbols

c	voltage factor in pu
cmax	voltage factor in pu for calculating maximum short circuit currents
ib (DC)	dc component of asymmetrical breaking current in amps
ib (SYM)	symmetrical breaking current (r.m.s.) in amps
ib (ASYM)	asymmetrical breaking current in amps (r.m.s.)
I"k	initial symmetrical short-circuit current in amps (r.m.s)
I"kQ	initial symmetrical short-circuit current in kA (r.m.s.) at feeder connection point Q
ILR	locked rotor current in amps of a asynchronous motor
ip	peak short-circuit current in amps
ip(B)	peak short-circuit current in amps by Method B of IEC 60909 standard
ip(C)	peak short-circuit current in amps by Method C of IEC 60909 standard
IrM	rated current in kA of a asynchronous motor
IrR	rated current in kA of a short circuit limiting reactor
KG	synchronous generator impedance correction factor in pu
KS	power station unit (PSU) with on-load-tap-changer (OLTC) impedance correction factor in pu
KT	transformer impedance correction factor in pu
KG,S	synchronous generator (of PSU with OLTC) impedance correction factor in pu
KT,S	transformer generator (of PSU with OLTC) impedance correction factor in pu
KSO	PSU without OLTC impedance correction factor in pu
KG,SO	synchronous generator (of PSU without OLTC) impedance correction factor in pu
KT,SO	transformer generator (of PSU without OLTC) impedance correction factor in pu
p	number of pole pairs of a motor
pG	range of generator voltage regulation in % on generator rated terminal voltage, pG=(UG-UrG)/UrG
pT	transformer tap range in % on a winding voltage base
SrG	three phase rated MVA of a synchronous machine
SrM	three phase rated MVA of a asynchronous motor
SCMVAQ	three phase short-circuit MVA at the feeder connection point Q
SBASE	three phase system MVA base
UG	generator terminal voltage, line-to-line (r.m.s.) in kV
Un	nominal system voltage, line-to-line (r.m.s.) in kV
UnQ	nominal system voltage, line-to-line (r.m.s.) in kV at the feeder connection point Q

UrG	rated voltage of a synchronous generator, line-to-line (r.m.s.) in kV
UrM	rated voltage of a asynchronous motor, line-to-line (r.m.s.) in kV
UrTLV	rated voltage of a LV winding of transformer, line-to-line (r.m.s.) in kV
UrTHV	rated voltage of a HV winding of transformer, line-to-line (r.m.s.) in kV
ukR	short circuit voltage of a short circuit current limiting reactor in % of its bus voltage
ΦrG	rated power factor of a synchronous generator
ΦrM	rated power factor of a asynchronous motor
ηrM	efficiency of a asynchronous motor in %

Network feeders or Equivalent Generators

$$Z_Q = \frac{c\,U_{nQ}}{\sqrt{3}\,I''_{kQ}}\ \Omega = \frac{c\,U^2_{nQ}}{SCMVA_Q}\ \Omega = \frac{c\,U_{nQ} \times SystemBaseMVA}{SCMVA_Q}\ \ pu$$

In PSS®E, there is no separate data record for equivalent generators. Their data is provided on the generator data record, and additional data to identify it as an equivalent generator is provided in (*.iec) file.

In PSS®E, provide this data without Voltage Factor C. PSS®E will calculate appropriate voltage factors and apply them.

Two and Three Winding Transformers

$$Z_T = R_T + jX_T \quad pu$$

$$K_T = 0.95\,\frac{C_{max}}{1 + 0.6x_T}$$

where:

RT	=	per unit resistance on transformer winding voltage, transformer winding MVA and nominal turns ratio base
	=	RT12, RT13, RT23 for three winding transformer
XT	=	per unit reactance on transformer winding voltage, transformer winding MVA and nominal turns ratio base
	=	XT12, XT13, XT23 for three winding transformer on a common MVA, winding voltage and nominal turns ratio ba
KT	=	impedance correction factor
	=	KT12, KT13, KT23 for three winding transformer

In PSS®E, provide transformer data without impedance correction factors. PSS®E will calculate appropriate impedance correction factors and apply them.

Overhead lines and cables

The overhead lines and cables impedance in pu on system MVA base and bus voltage base is given by:

$Z_L = R_L + jX_L$ pu

There is no impedance correction factor for overhead lines and cables.

Short-circuit limiting reactors

The short circuit current limiting reactor impedance in pu on system MVA base and bus voltage base is given by:

$$Z_R = \frac{u_{kR}}{100\%}$$

where ukR is the impedance voltage in percent on system base MVA and bus voltage base.

There is no impedance correction factor for short-circuit limiting reactors.

Synchronous Generators

$$Z_{GK} = K_G (R_G + j X''_{dv}) \text{ pu}$$

$$K_G = \frac{U_n}{U_{rG}} \frac{c_{max}}{1 + X''_{dv} \sin\phi_{rG}}$$

where:

RG =

generator resistance in per unit on generator terminal voltage base and generator MVA base

X"dv =

saturated subtransient reactance in per unit on generator terminal voltage base and generator MVA base

- If terminal voltage of the generator is different from UrG , KG is calculated from UG=UrG(1+pG).
- If X"dv and X"qv are different, the negative sequence reactance, X(2)G = (X"d + X"q)/2 will be used in fault current calculation.

The PSS®E generator data record does not include generator rated voltage, rated power factor and generator voltage regulation. This additional data is provided in (*.iec) file.

In PSS®E, provide synchronous machines data without impedance correction factors. PSS®E will calculate appropriate impedance correction factors and apply them.

Synchronous Compensators and Motors

These are treated same as synchronous generators.

Power Station Units (Synchronous Generators with GSU transformer model)

Transformer with on-load-tap-changer (OLTC)

- Faults on network buses

$$Z_S = K_S[(R_G + j X''_{dv}) + (R_T + j X_T)] \ \text{pu}$$

$$K_S = \frac{U^2_{nQ}}{U^2_{rG}} \frac{U^2_{rTLV}}{U^2_{rTHV}} \frac{c_{max}}{1 + |X''_{dv} - x_T| \sin\phi_{rG}}$$

- Faults inside a power station unit (on bus connecting generator and unit transformer)

$$K_{G,S} = \frac{c_{max}}{1 + X''_{dv} \sin\phi_{rG}}$$

$$K_{T,S} = \frac{c_{max}}{1 - x_T \sin\phi_{rG}}$$

Transformer without on-load-tap-changer (without OLTC)

- Faults on network buses

$$Z_{SO} = K_{SO}[(R_G + j X''_{dv}) + (R_T + j X_T)] \ \text{pu}$$

$$K_{SO} = \frac{U_{nQ}}{U_{rG}(1 + p_G)} \frac{U_{rTLV}}{U_{rTHV}} (1 \pm p_T) \frac{c_{max}}{1 + X''_{dv} \sin\phi_{rG}}$$

- Faults inside a power station unit (on bus connecting generator and unit transformer)

$$K_{G,SO} = \frac{1}{1 + p_G} \frac{c_{max}}{1 + X''_{dv} \sin\phi_{rG}}$$

$$K_{T,SO} = \frac{1}{1 + p_G} \frac{c_{max}}{1 + X_T \sin\phi_{rG}}$$

Note: PSS®E generator data record does not include rated voltage, rated power factor and voltage regulation. This additional data is provided in (*.iec) file.

In PSS®E, provide power station units data without impedance correction factors. PSS®E will calculate appropriate impedance correction factors and apply them.

Asynchronous Motors

$$S_{rM} = \frac{P_{rM}}{\sin\phi_{rM}\ \eta_{rM}}$$

$$Z_M = \frac{1}{I_{LR}/I_{rM}} \frac{U_{rM}}{\sqrt{3}\ I_{rM}}\ \Omega = \frac{1}{I_{LR}/I_{rM}}\quad \text{pu}$$

In PSS®E, asynchronous motors can be represented on their own data records or on generator data records. To compute IEC symmetrical breaking currents, additional data required for asynchronous motors is provided in (*.iec) file. There is no IEC impedance correction applied to asynchronous motors.

Ignored Devices/Components

The IEC 60909 short circuit calculation ignores devices in positive and negative sequences, but considers in zero sequences the following:

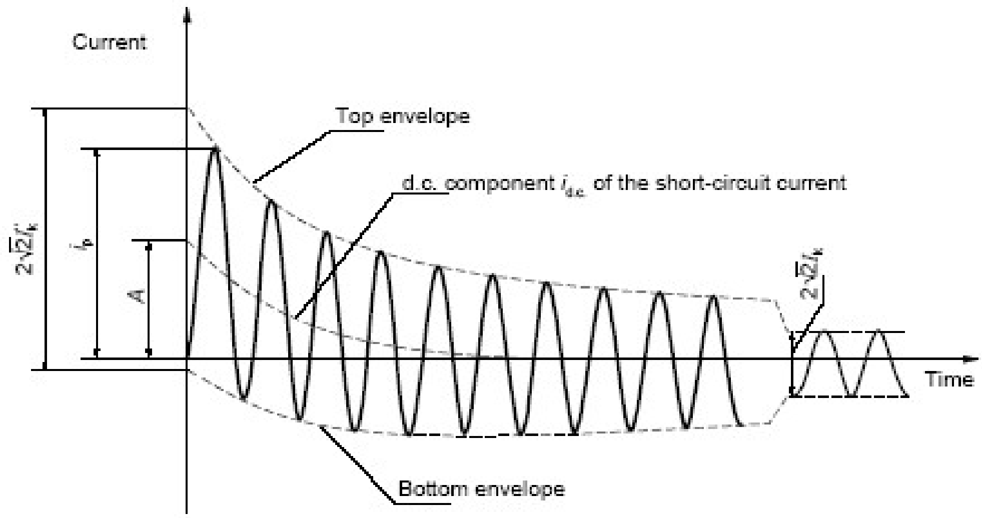
- Non-rotating loads
- Bus fixed shunts
- Line charging susceptances
- Line fixed shunts
- Switched shunts

The following devices are ignored in all sequences:

- FACTS devices
- Two terminal and multi terminal dc lines
- VSC dc lines

11.10.2. Calculation of Short Circuit Currents

Figure 11.103, "Characteristics of Asymmetrical Three-phase Short Circuit Current" shows the characteristics of the asymmetrical three-phase short circuit current. Activity IECS calculates these currents.



I_k'' = initial symmetrical short-circuit current

i_p = peak short-circuit current

I_k = steady-state short-circuit current

$i_{d.c.}$ = d.c. component of short-circuit current

A = initial value of the d.c. component $i_{d.c.}$

Figure 11.103. Characteristics of Asymmetrical Three-phase Short Circuit Current

Equivalent Voltage Source at the Short Circuit Location

The short circuit currents are driven by an equivalent voltage source at the short circuit location. The equivalent voltage source is the only active voltage source in the system. All network feeders, synchronous machines, and asynchronous machines are replaced by their internal impedances. The operational data of the system such as loading, excitation of generators etc. are ignored. (Refer IEC 60909-0 Section 2.3.1). The equivalent voltage source is given by:

$$\text{Equivalent Source Voltage} = \frac{c\,U_n}{\sqrt{3}}\ \text{kV} = c\,\frac{U_{n\ \text{nominal}}}{U_{n\ \text{base}}}\ \text{pu} = c\ \ \text{pu}$$

The voltage factor c is selected as below, considering that the highest voltage in normal system does not differ, on average, by more than approximately +5 % (LV systems) or +10 % (HV systems) from the nominal system voltage Un. (Refer Table 1 of IEC 60909-0). The values are in per unit on a bus voltage base.

Nominal Voltage Un (LL r.m.s.)	Voltage factor c for the calculation of	
	maximum short-circuit currents, cmax (1)	minimum short-circuit currents, cmin
Low voltage 100 V to 1000 V (IEC 60038, table I)	1.05 (3) 1.10 (4)	0.95

Nominal Voltage Un (LL r.m.s.)	Voltage factor c for the calculation of	
	maximum short-circuit currents, cmax [1]	minimum short-circuit currents, cmin
Medium voltage >1 kV to 35 kV (IEC 60038, table III)	1.10	1.00
High Voltage [2] >35 kV (IEC 60038, table IV)		

[1] cmaxUn should not exceed the highest voltage Um for power systems equipment.

[2] If no nominal voltage is defined cmaxUn= Um or cminUn= 0.90 × Um should be applied.

[3] For low-voltage systems with a tolerance of +6 %, for example systems renamed from 380 V to 400 V (LL r.m.s.).

[4] For low-voltage systems with a tolerance of +10 %.

Initial Symmetrical Short Circuit Current, I"k

Thevenin equivalent impedance as seen from short circuit location:

Z1 = Positive sequence

Z2 = Negative sequence

Z0 = Zero sequence

Sequence currents in Phase A at short circuit location:

Ia1 = Positive sequence

Ia2 = Negative sequence

Ia0 = Zero sequence

Phase currents at short circuit location:

Ia = Phase A

Ib = Phase B

Ic = Phase C

Sequence Voltages in Phase A at short circuit location:

Va1 = Positive sequence

Va2 = Negative sequence

Va0 = Zero sequence

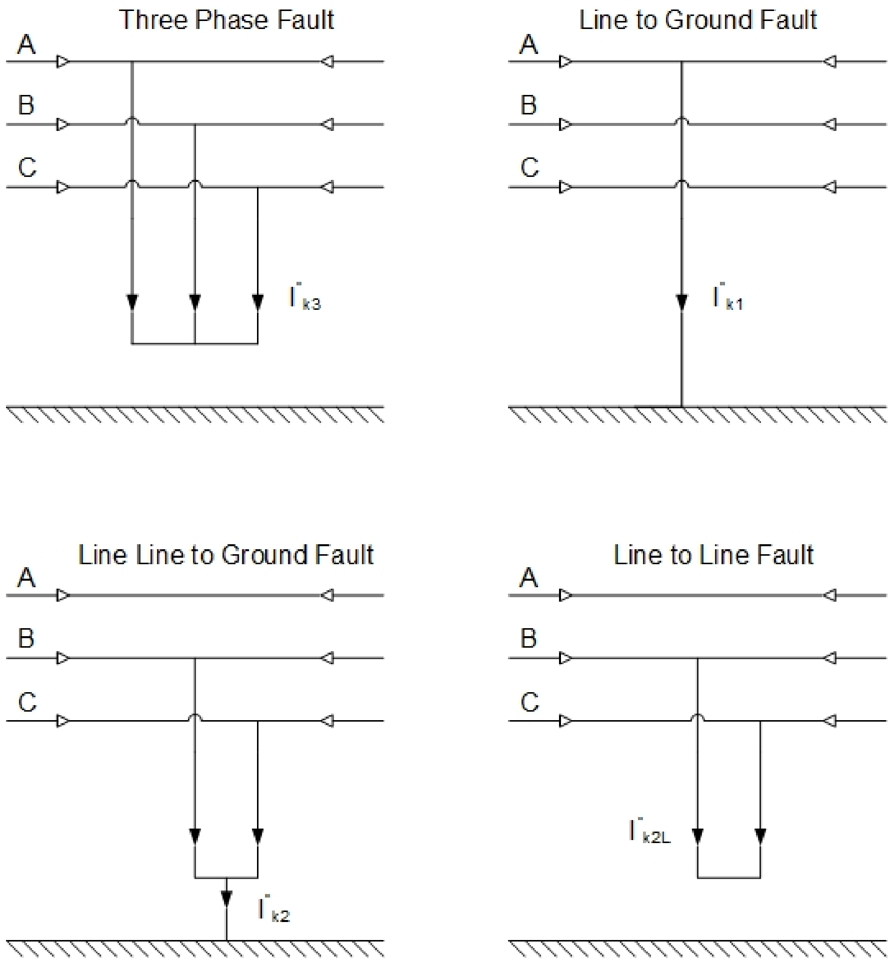


Figure 11.104. Characterization of Short Circuits and their Currents

Three Phase Fault (3PH)

$$I_{a1} = I''_{k3} = \frac{c\,U_{n\,pu}}{Z_1}\;\frac{S_{BASE}}{\sqrt{3}\,U_n}\ \text{A rms}$$

Line to Ground Fault (LG)

$$I_{a1} = I_{a2} = I_{a0},\ I_b = 0,\ I_c = 0,\ V_a = 0$$

$$I_{a0} = \frac{c\, U_{n\,pu}}{Z_1 + Z_2 + Z_0} \quad pu$$

$$I''_{k1} = 3 I_{a0} \frac{S_{BASE}}{\sqrt{3}\, U_n} \ \text{A rms}$$

Two Lines to Ground Fault (LLG)

$$I_a = 0,\ V_b = V_c = 0,\ V_{a1} = V_{a2} = V_{a0}$$

$$I_{a1} = \frac{c\, U_{n\,pu} (Z_2 + Z_0)}{Z_1 Z_2 + Z_1 Z_0 + Z_2 Z_0} \quad pu$$

$$V_{a1} = V_{a2} = V_{a0} = V_{a\ prefault} - I_{a1} Z_1$$

$$I_{a2} = -\frac{V_{a2}}{Z_2}$$

$$I_{a0} = -\frac{V_{a0}}{Z_0}$$

$$I''_{k2} = 3 I_{a0} \frac{S_{BASE}}{\sqrt{3}\, U_n} = \frac{3c\, U_{n\,pu} Z_2}{Z_1 Z_2 + Z_1 Z_0 + Z_2 Z_0} \frac{S_{BASE}}{\sqrt{3}\, U_n} \ \text{A rms}$$

Line to Line Fault (LL)

$$I_a = 0,\ I_b = -I_c,\ V_{a1} = V_{a2},\ V_b = V_c,\ I_{a0} = 0,\ I_{a2} = -I_{a1}$$

$$I_{a1} = \frac{c\, U_{n\,pu}}{Z_1 + Z_2} \quad pu$$

$$I''_{k2L} = I_b = a^2 I_{a1} + a I_{a2} = (a^2 - a) I_{a1} = -j\sqrt{3}\, I_{a1} = (-j\sqrt{3}) \frac{c\, U_{n\,pu}}{Z_1 + Z_2} \frac{S_{BASE}}{\sqrt{3}\, U_n} \ \text{A rms}$$

If Z0 < Z1 and Z2=Z1

I"k2 is the largest of all initial symmetrical short circuit currents in pu.

I"k1 is larger than the three phase short circuit current I"k3, but smaller than I"k2. However, I"k1 will be the largest current to be interrupted by a circuit breaker if 0.23 < Z0/Z1 < 1.0.

Peak Short Circuit Current, ip

For all types of faults (3PH, LL, LLG, and LG), the peak short circuit current, ip, in ampere r.m.s., is calculated as:

$$i_p = K\sqrt{2}\, I_k'' \quad \text{A peak}$$

$$K = 1.02 + 0.98e^{-3R/X}$$

The factor K is determined using one of the following methods.

Method A: Uniform ratio R/X

For this method the factor K is determined taking the smallest ratio of R/X or the largest ratio of X/R of all branches of the network.

It is only necessary to choose the branches that carry partial short-circuit currents at nominal voltage corresponding to the short-circuit location and branches with transformers adjacent to the short-circuit location. Any branch may be a series combination of several series impedances.

Method B: Ratio R/X at the short circuit location

For this method the factor K is multiplied by a factor 1.15 to cover inaccuracies caused by using the ratio Rk / Xk from a network reduction with complex impedances.

$K_{(b)} = 1.15K$

The factor K is found for the ratio Rk / Xk given by the short-circuit impedance Zk = Rk + jXk at the short-circuit location F, calculated for frequency f = 50 Hz or 60 Hz.

Method C: Equivalent frequency fc

An equivalent impedance Zc of the system as seen from the short circuit location is calculated assuming a frequency fc = 20 Hz (for a nominal frequency f = 50 Hz) or fc = 24 Hz (for a nominal frequency f = 60 Hz). The R/X or X/R ratio is then determined according to:

$$\frac{R}{X} = \frac{R_c}{X_c}\,\frac{f_c}{f} = 0.4\,\frac{R_c}{X_c}$$

Method C is recommended for meshed networks.

When using this method in meshed networks with transformers, generators and power station units, the impedance correction factors (KT, KG, KS and KSO) calculated at 50 Hz or 60 Hz are used.

DC Component of the Asymmetrical Short Circuit Current, idc

The maximum dc component idc of the asymmetrical three-phase short circuit current, in A peak, is calculated by:

$i_{dc} = \sqrt{2}\ I''_k e^{-2\pi f t R/X}$ A peak

where:

f is the system nominal frequency in Hz,

t is the breaker contact parting time in seconds,

R/X is the ratio according to the Methods A and C for non-meshed networks.

For meshed networks, the ratio R/X or X/R is to be determined by the Method C. Depending on the product (f . t), the equivalent frequency fc should be used as follows:

f . t	<1	<2.5	<5	<12.5
fc/f	0.27	0.15	0.092	0.055

Symmetrical Short Circuit Breaking Current, Ib

The three-phase symmetrical short-circuit breaking currents are calculated as:

$$I_b = I''_k - \sum_i \frac{\Delta U''_{Gi}}{cU_n / \sqrt{3}} (1 - \mu_i) I''_{kGi} - \sum_j \frac{\Delta U''_{Mj}}{cU_n / \sqrt{3}} (1 - \mu_j q_j) I''_{kMj} \text{ A rms}$$

$$\Delta U''_{Gi} = j X''_{dik} I''_{kGi} = j(K_G \text{ or } K_S \text{ or } K_{SO}) X''_{di} I''_{kGi}$$

$$\Delta U''_{Mj} = j X''_{Mj} I''_{kMj}$$

Converting these equations to per unit:

$$I_b = I''_k - \sum_i \frac{j K_v X''_{di} I''_{kGi}}{c_f} (1 - \mu_i) I''_{kGi} - \sum_j \frac{j X''_{Mj} I''_{kMj}}{c_f} (1 - \mu_j q_j) I''_{kMj} \quad \text{A pu}$$

where:

Kv = KG or KS or KSO

cf = C factor at faulted bus

For synchronous and asynchronous machines, the factors μi, μj are given by:

$$\mu = 0.84 + 0.26e^{-0.26 I''_{kG}/I_{rg}} \qquad \text{for } t_{min} = 0.02 \text{ seconds}$$

$$\mu = 0.71 + 0.51e^{-0.30 I''_{kG}/I_{rg}} \qquad \text{for } t_{min} = 0.05 \text{ seconds}$$

$$\mu = 0.62 + 0.72e^{-0.32 I''_{kG}/I_{rg}} \qquad \text{for } t_{min} = 0.10 \text{ seconds}$$

$$\mu = 0.56 + 0.94e^{-0.38 I''_{kG}/I_{rg}} \qquad \text{for } t_{min} \geq 0.25 \text{ seconds}$$

t_{min} is the minimum breaker contact parting time.

If $I''_{kG} / I_{rG} \leq 2.0$, $\mu = 1$ for all t_{min}

For asynchronous motors, the factors qj are given by:

$$q = 1.03 + 0.12\ 1n(P_{rm}/p) \qquad \text{for } t_{min} = 0.02 \text{ seconds}$$

$$q = 0.79 + 0.12\ 1n(P_{rm}/p) \qquad \text{for } t_{min} = 0.05 \text{ seconds}$$

$$q = 0.57 + 0.12\ 1n(P_{rm}/p) \qquad \text{for } t_{min} = 0.10 \text{ seconds}$$

$$q = 0.26 + 0.12\ 1n(P_{rm}/p) \qquad \text{for } t_{min} \geq 0.25 \text{ seconds}$$

P_{rM} is the motor rated three phase active power in MW.

If q > 1, assume q = 1

c U_n / √ 3 is the equivalent voltage source at the short-circuit location.

Δ U''_{Gi}, Δ U''_{Mj} are the initial internal voltage drop of the synchronous machines (i) and the asynchronous motors (j), respectively.

X"dvik is the corrected saturated subtransient reactance of the synchronous machine (i).

XMj is the reactance for the asynchronous motor (j).

I"kGi, I"kM j are the contributions to the initial r.m.s. symmetrical short-circuit current from the synchronous machines (i) and the asynchronous motors (j) as measured at the terminals of the machines. Because flux decay following a short circuit is not taking into account in the computation of unbalanced faults (IEC 60909 Standard, Section 4.5.2.4), the short-circuit breaking current for unbalanced faults are estimated from the following expressions:

Ib1 = I"k1 (line to ground fault)

Ib2E = I"k2E (two lines to ground fault)

Ib2 = I"k2 (line to line fault)

Asymmetrical Short Circuit Breaking Current, Ib asym

$$I_{b\ asym} = \sqrt{I^2b + i^2dc} \qquad \text{A rms}$$

11.10.3. Example

Figure 11.105, "IEC High Voltage ac Test Network 380/110/30/10 kV" shows a three phase ac system test network given in IEC 60909-4, Section 6, Figure 16.

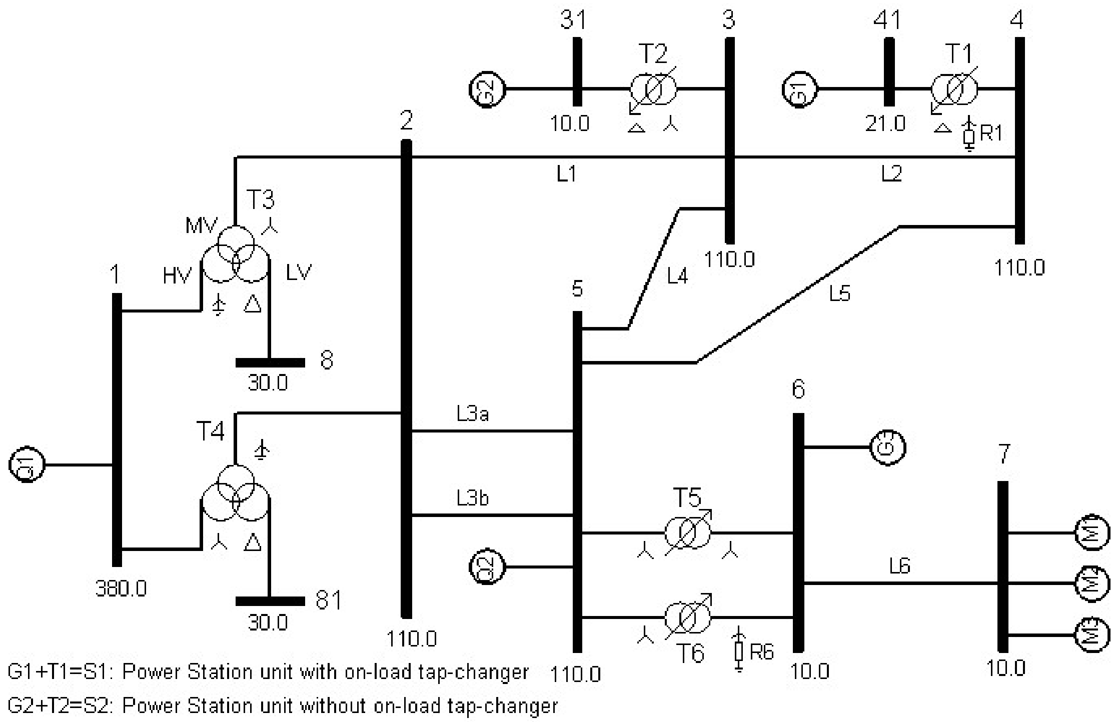


Figure 11.105. IEC High Voltage ac Test Network 380/110/30/10 kV

Data of Electrical Equipment

PSS®E System MVA Base = SBASE = 100 MVA

Network Feeders

$$Z_Q = \left(\frac{U_{nQ}}{\sqrt{3}\, I''_{kQmax}}\right) / Z_{base} = \left(\frac{U_{nQ}}{\sqrt{3}\, I''_{kQmax}}\right) / \left(\frac{U^2{}_{nQ}}{M_{base}}\right) = \frac{M_{base}}{\sqrt{3}\, I''_{kQmax}\, U_{nQ}}$$

$$R_Q = (R_Q / X_Q)\, X_Q \qquad\qquad X_Q = \frac{Z_Q}{\sqrt{1 + (R_Q / X_Q)^2}}$$

Q1 Data	*Q1* PSS®E *Data*
UnQ = 380 kV I"kQmax = 38 kA cmax = 1.1 RQ/XQ = 0.1 X(0)Q/XQ = 0.15 R(0)Q/X(0)Q = 0.15	MBASE = 100 MVA RQ = Rsource = R+ve = R-ve = 0.000397843 pu XQ = Xsource = X+ve = X-ve = 0.00397843 pu R0 = 0.00179029 pu X0 = 0.0119353 pu

Q2 Data	*Q2* PSS®E *Data*
UnQ = 110 kV I"kQmax = 16 kA cmax = 1.1 RQ/XQ = 0.1 X(0)Q/XQ = 3.3 R(0)Q/X(0)Q = 0.2	MBASE = 100 MVA RQ = Rsource = R+ve = R-ve = 0.00326412 pu XQ = Xsource = X+ve = X-ve = 0.0326412 pu R0 = 0.0215432 pu X0 = 0.107716 pu

Generator

G3 Data	*G3* PSS®E *Data*
UrG = 10.5 kV SrG = 10 MVA pG = ± 5 % * x"d = 0.1 pu xdsat = 1.8 pu cos ϕ rG = 0.80 RG = 0.018 Ω	MBASE = 10 MVA urG = 10.5 kV un= 10 kV pG = ± 5 % cos ϕ rG = 0.80 RG = Rsource = R+ve = R-ve = 0.0018 pu (on MBASE, un) XG = Xsource = X+ve = X-ve = 0.11025 pu (on MBASE, un)

*For the calculation, a constant value UG = UrG is assumed.

Power Station Units

$$Z_{G\ base} = \frac{U_{rG}^2}{M_{base}} = \frac{U_{rG}^2}{S_{rG}}$$

$$RG = \frac{R_G\ \Omega}{Z_{G\ base}} \quad pu \qquad R_T = \frac{u_{Rr}\%}{100} \quad pu$$

$$X_G = X_d'' \quad pu \qquad X_T = \sqrt{u_{kr}^2 - u_{Rr}^2} \quad pu$$

S1 Data	*G1* and T1 PSS®E *Data*
UrG = 21 kV	**G1**
SrG = 150 MVA	MBASE = 150 MVA
x"d = 0.14 pu	urG = 21 kV
xdsat = 1.8 pu	cos ϕ rG = 0.85
cos ϕ rG = 0.85	RG = Rsource = R+ve = R-ve = 0.000680272 pu
RG = 0.002 Ω [a]	XG = Xsource = X+ve = X-ve = 0.14 pu
UrTHV / UrTLV = 115 kV / 21 kV	**T1**
SrT = 150 MVA	SBASE12 = 150 MVA
ukr = 16 %	WINDV1 = 115 kV
uRr = 0.5 %	WINDV2 = 21 kV
YNd5 with on-load tap-changer	RT = R12 = 0.005 pu
pT = ± 12 %	XT = X12 = 0.159922 pu
X(0)T / XT = 0.95	R0 = 0.00333333 pu (on SBASE of 100 MVA and 115 kV)
R(0)T / RT = 1.0	X0 = 0.101284 pu (on SBASE of 100 MVA and 115 kV)
	Rg = 0
	Xg = 0.166352 pu (Reactor R1 on 100 MVA, 115 kV base)
	Connection Code = 2

[a]Operated only in the overexcited region.

S2 Data	*G2* and T2 PSS®E *Data*
UrG = 10.5 kV	**G2**
SrG = 100 MVA	MBASE = 100 MVA
pG = ± 7.5 %	urG = 10.5 kV, un = 10 kV

S2 Data	*G2* and T2 PSS®E *Data*
x"d = 0.16 pu xdsat = 2.0 pu cos ϕ rG = 0.90 RG = 0.005 Ω UrTHV / UrTLV = 120 kV / 10.5 kV SrT = 100 MVA ukr = 12 % uRr = 0.5 % YNd5 without on-load tap-changer or off-load taps X(0)T / XT = 1.0 R(0)T / RT = 1.0	pG = ± 7.5 % cos ϕ rG = 0.90 RG = Rsource = R+ve = R-ve = 0.005 pu (on MBASE, un) XG = Xsource = X+ve = X-ve = 0.1764 pu (on MBASE, un) **T2** SBASE12 = 100 MVA WINDV1 = 120 kV WINDV2 = 10.5 kV RT = R12 = 0.005 pu XT = X12 = 0.119896 pu R0 = 0.005 pu (on SBASE of 100 MVA and 120 kV) X0 = 0.119896 pu (on SBASE of 100 MVA and 120 kV) Connection Code = 4

Network transformers

$$R_{12} = \frac{u_{RrHVMV}\,\%}{100}\ \text{pu} \qquad X_{12} = \sqrt{u_{krHVMV}^2 - u_{RrHVMV}^2}\ \text{pu}$$

$$R_{23} = \frac{u_{RrMVLV}\,\%}{100}\ \text{pu} \qquad X_{12} = \sqrt{u_{krMVLV}^2 - u_{RrMVLV}^2}\ \text{pu}$$

$$R_{31} = \frac{u_{RrHVLV}\,\%}{100}\ \text{pu} \qquad X_{12} = \sqrt{u_{krHVLV}^2 - u_{RrHVLV}^2}\ \text{pu}$$

T3 and T4 Data [a]	*T3 and T4* PSS®E *Data*
UrTHV = 400 kV	SBASE12 = 350 MVA
UrTMV = 120 kV	SBASE23 = 50 MVA
UrTLV = 30 kV	SBASE31 = 50 MVA
SrTHV = 350 MVA	WINDV1 = 400 kV
SrTMV = 350 MVA	WINDV2 = 120 kV
SrTLV = 50 MVA	WINDV3 = 30 kV
ukrHVMV = 21%	R12 = 0.0026 pu (on base of 350 MVA, 400 kV)
ukrHVLV = 10%	X12 = 0.209984 (on base of 350 MVA, 400 kV)

T3 and T4 Data [a]	*T3 and T4 PSS®E Data*
ukrMVLV = 7%	R23 = 0.0016 pu (on base of 50 MVA, 120 kV)
uRrHVMV = 0.26%	X23 = 0.0699817 (on base of 50 MVA, 120 kV)
uRrHVLV = 0.16%	R31 = 0.0016 pu (on base of 50 MVA, 30 kV)
uRrMVLV = 0.16%	X31 = 0.0999872 (on base of 50 MVA, 30 kV)
X(0)TMV/XTMVHV = 2.1	R0 = 0.000742857 pu (on base of 100 MVA, 120 kV)
R(0)TMV/RTMVHV = 1.0	X0 = 0.12599 pu (on base of 100 MVA, 120 kV)
pT = ± 16 %	Connection Code:
Starpoint earthing:	= 244 for T3
T3 - at high-voltage side,	= 424 for T4
T4 - at medium-voltage side.	

[a]Three-winding network transformers YNynd5 with on-load tap changer at high voltage side.

T5 and T6 Data [a]	T5 and T6 PSS®E Data
UrTHV = 115 kV	SBASE12 = 31.5 MVA
UrTMV = 10.5 kV	WINDV1 = 115 kV
SrT = 31.5 MVA	WINDV2 = 10.5 kV
ukr = ukrHVMV	RT = R12 = 0.005 pu
ukr = 12 %	XT = X12 = 0.119896 pu
uRr = 0.5 %	Connection Code = 4 (T5), 3 (T6)

[a]Three-winding network transformer YNynd5, (with no load on a winding) treated as a two-winding transformer

Asynchronous motors

$$Sr_M = \frac{P_{rM}}{\cos\phi_{rM}\ \eta_{rM}}$$

$$Q_{min} = Q_{max} = S_{rM} \sin\phi_{rM}$$

$$Z_M = \frac{1}{I_{LR} / I_{RM}} \qquad X_M = 0.995\ Z_M \qquad R_M = 0.1\ X_M$$

M1	*M1 PSS®E Data*
UrM = 10 kV	- When specified on generator data record
PrM = 5 MW	MBASE = 5.82751 MVA
cos ϕ rM = 0.88	PG = -5.0 MW
η	QT = QB = 2.76791 MVAR

M1	*M1 PSS®E Data*
rM = 97.5 % ILR/IrM = 5 p = 1 (pair of poles)	RM = Rsource = R+ve = R-ve = 0.0199 pu XM = Xsource = R+ve = R-ve = 0.199 pu - When specified on induction machine data record BCODE=1, MBASE=5 MW PCODE=1, PSET=5 MW ILR2IR=5, RM2XM=0.1

M2 and M3 Data	*M2 and M3 PSS®E Data*
UrM = 10 kV PrM = 2 MW cos ϕ rM = 0.89 η rM = 96.8 % ILR/IrM = 5.2 p = 2 (pair of poles)	- When specified on generator data record MBASE = 2.32148 MVA PG = -2.0 MW QT = QB = 1.0585 MVAR RM = Rsource = R+ve = R-ve = 0.0191346 pu XM = Xsource = R+ve = R-ve = 0.191346 pu - When specified on induction machine data record BCODE=1, MBASE=2 MW PCODE=1, PSET=2 MW ILR2IR=5.2, RM2XM=0.1

Reactors

R1 Data	*R1 PSS®E Data (Transformer T1 ground impedance)*
XR1 = 22 Ω RR1 << XR1 (short-circuit limiting reactor)	Rg = 0 Xg = 0.166352 pu (on 100 MVA and 115 kV base)

R6: Arc suppression coil for the 10 kV network with resonance neutral earthing.

Overhead lines and cables

Line	Length (km)	Z+ve (Ω /km)	Zzero (Ω /km)	PSS®E data (for the entire line length)	
				Z+ve (pu)	Zzero (pu)
L1	20	0.12+j0.39	0.32+j1.26	0.0198347+j0.0644628	0.0528926+j0.208264

Line	Length (km)	Z+ve (Ω /km)	Zzero (Ω /km)	PSS®E data (for the entire line length)	
				Z+ve (pu)	Zzero (pu)
L2	10	0.12+j0.39	0.32+j1.26	0.00991736+j0.0322314	0.0264463+j0.104132
L3a	5	0.12+j.39	0.52+j1.86	0.00495868+j0.0161157	0.0214876+j0.0768595
L3b	5	0.12+j0.39	0.52+j1.86	0.00495868+j0.0161157	0.0214876+j0.0768595
L4	10	0.096+j0.388	0.22+j1.10	0.00793388+j0.0320661	0.0181818+j0.0909091
L5	15	0.12+j0.386	0.22+j1.10	0.014876+j0.0478512	0.0272727+j0.136364
L6	1	0.082+j0.086	-	0.082+j0.086	-

IECS Calculated Short Circuit Currents

Following results show the comparison of short circuit currents obtained from PSS®E activity IECS and results given in IEC 60909-4 standard Sections 6.3.1 and 6.3.2. Ib sym, Ib asym and idc are calculated with breaker contact parting time t = 0.1 seconds, network base frequency=50 Hz. 'calculated' row values show the 3 Ph fault currents calculated by network reduction (see section 10.10.3.3).

Three Phase Short Circuit Currents

Solution Method	Faulted Bus	I"k	ip Method B	ip Method C	idc	Ib sym	Ib asym
		kA	kA	kA	kA	kA	kA
standard	1	40.6447	100.5766	100.5677	-	40.645	-
PSS®E		40.6447	100.5766	100.5676	2.7396	40.6426	40.7348
calculated		40.6447	100.5766	100.5677	2.7396	-	-
standard	2	31.7831	80.8249	80.6079	-	31.570	-
PSS®E		31.7830	80.5119	80.6079	12.7917	31.5777	34.0702
calculated		31.7831	80.5120	80.6079	12.7917	-	-
standard	3	19.6730	45.8249	45.8111	-	19.388	-
PSS®E		19.6730	45.8249	45.8111	1.5159	19.4020	19.4611
standard	4	16.2277	36.8041	36.8427	-	16.017	-
PSS®E		16.2277	36.8041	36.8427	2.6296	16.0211	16.2354
calculated		16.2277	36.8041	36.8427	2.6296	-	-
standard	5	33.1894	83.6266	83.4033	-	32.795	-
PSS®E		33.1894	83.6265	83.4033	3.9796	32.8065	33..470
calculated		33.1894	83.6266	83.4033	3.9796	-	-
standard	6	37.5629	99.1910	98.1434	-	34.028	-
PSS®E		37.5628	95.1908	99.1432	15.1072	34.0131	37.2171
calculated		37.5629	95.1910	99.1434	15.1071	-	-
standard	7	25.5895	59.0944	51.6899	-	23.212	-
PSS®E		25.5894	59.0943	51.6898	0.0671	23.1936	23.1937
calculated		25.5895	59.0944	51.6899	0.0671	-	-
standard	8	13.5778	36.9201	36.9227	-	13.578	-
PSS®E		13.5778	36.9201	36.9227	9.2936	13.5778	16.4538

Line-to-Earth Short Circuit Currents

Solution Method	Faulted Bus	I"k	ip Method B	ip Method C	idc	Ib sym	Ib asym
		kA	kA	kA	kA	kA	kA
standard	2	15.9722	-	39.9641	-	-	-
PSS®E		15.9722	39.5932	39.99641	10.2186	15.9722	18.9613
standard	3	10.4106	-	24.2635	-	-	-
PSS®E		10.4106	24.1604	24.2635	0.8528	10.4106	10.4454
standard	4	9.0498	-	21.0415	-	-	-
PSS®E		9.0498	20.9198	21.0415	2.0671	9.0498	9.2829
standard	5	17.0452	-	41.4303	-	-	-
PSS®E		17.0452	41.2689	41.4303	2.4561	17.0452	17.2212

Three Phase Fault Current Calculation with Network Reduction

1. Positive Sequence Single line diagram based on network single line diagram is illustrated in Figure 10-104.

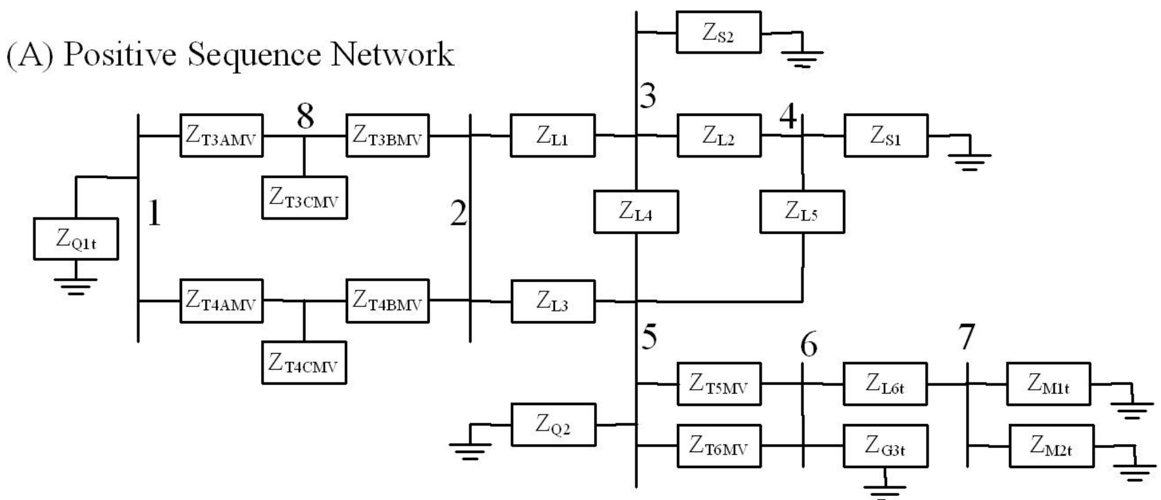


Figure 11.106. Positive Sequence Network

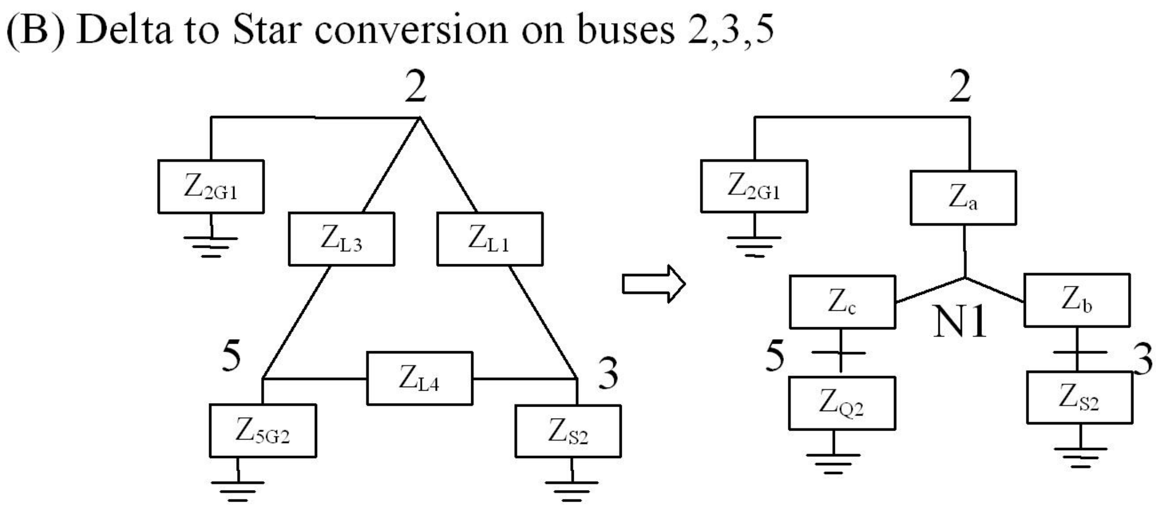


Figure 11.107. Delta to Star conversion on buses 2, 3, 5

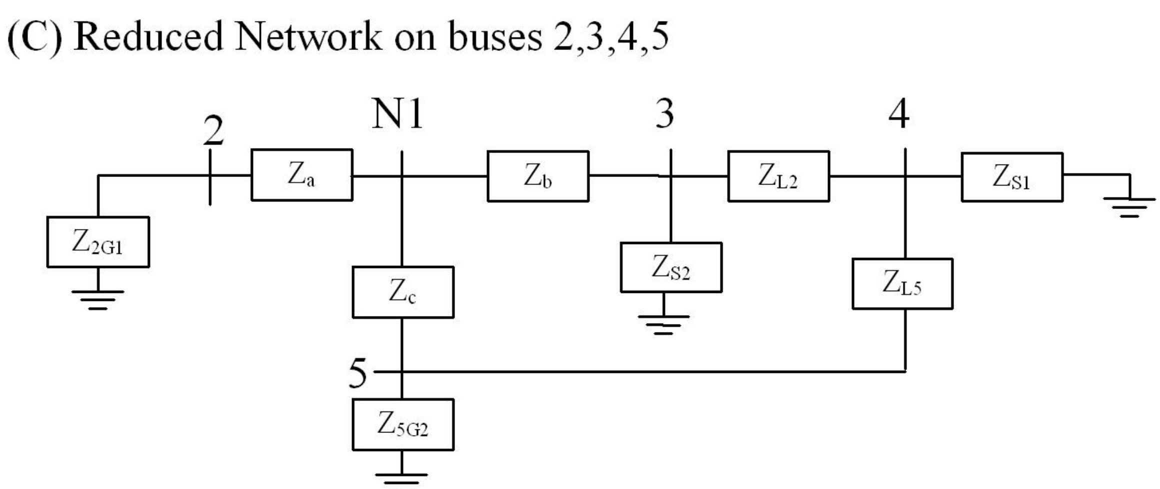


Figure 11.108. Reduced network on buses 2, 3, 4, 5

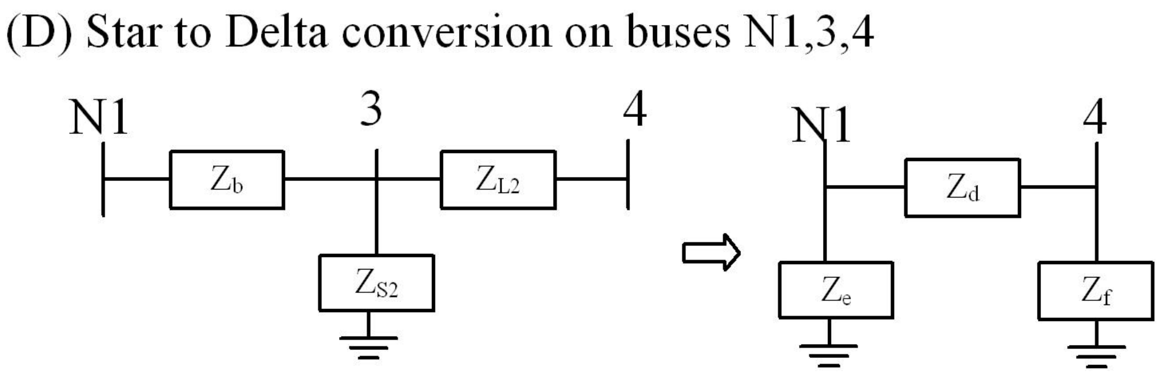


Figure 11.109. Star to Delta conversion on buses N1, 3, 4

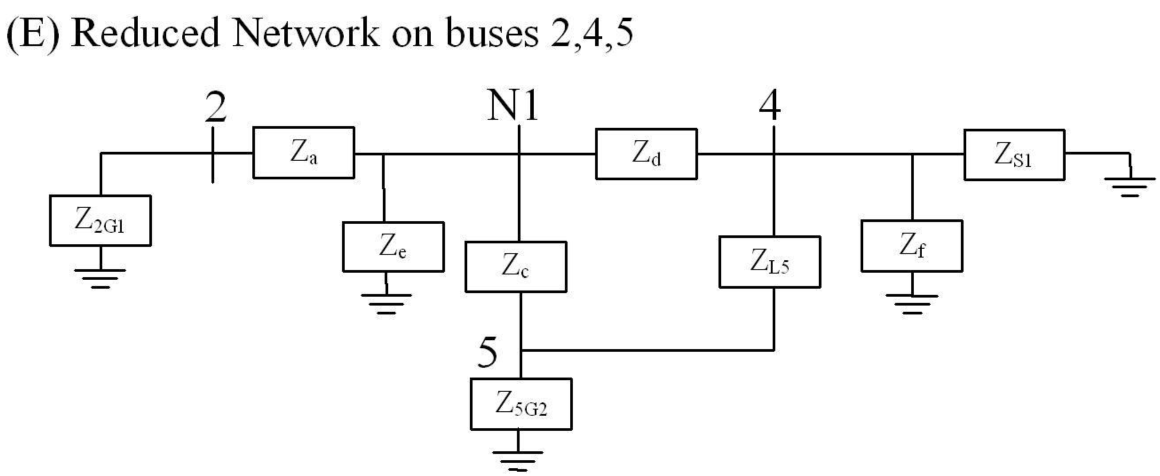


Figure 11.110. Reduced Network on buses 2, 4, 5

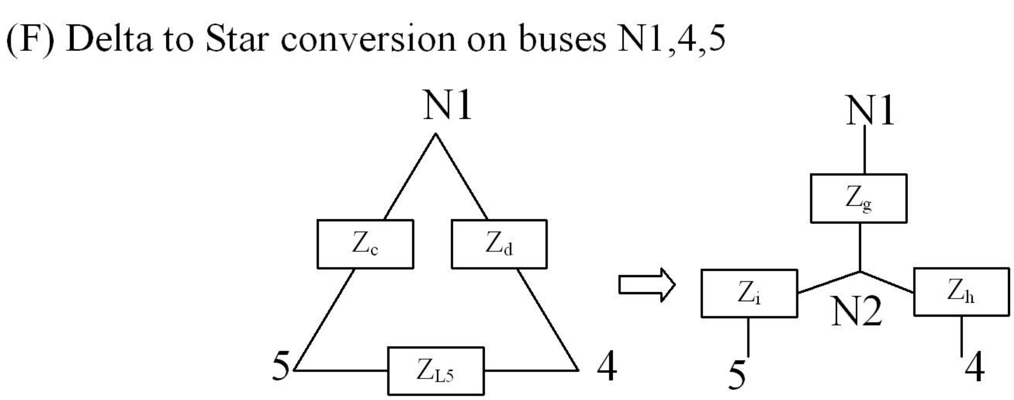


Figure 11.111. Delta to Star conversion on buses N1, 4, 5

(G) Reduced Network on buses 2,4,5

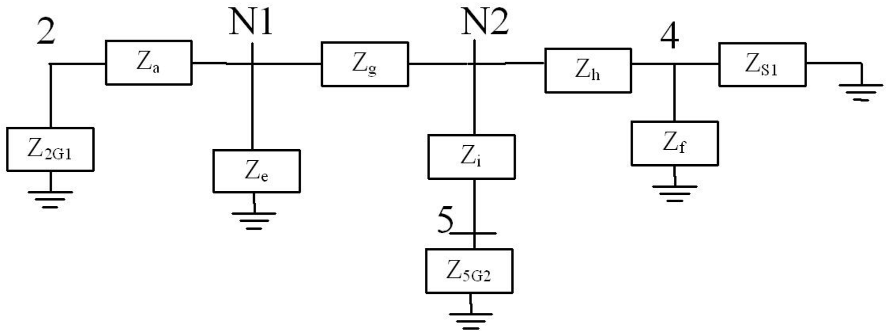


Figure 11.112. Reduced Network on buses 2, 4, 5

2. Positive Sequence Network Reduction Steps

tion of two impedances is represented as

$$Z = Z_p \| Z_q = \frac{Z_p \times Z_q}{Z_p + Z_q}$$

- Reducing ZQ2, Bus 6 and Bus 7 (Fig A)

$$\begin{aligned} Z_{7G} &= Z_{M1t} \| Z_{M2T} \\ Z_{6G1} &= Z_{L6t} + Z_{7G} \\ Z_{6G2} &= Z_{G3t} + Z_{6G1} \\ Z_{56} &= Z_{T5MV} \| Z_{T6MV} \\ Z_{5G1} &= Z_{56} + Z_{6G2} \\ Z_{5G2} &= Z_{Q2} + Z_{5G1} \end{aligned}$$

- Reducing Bus 1 to Bus 2 (Fig A)

$$\begin{aligned} Z_{12T3} &= Z_{T3AMV} + Z_{T3BMV} \\ Z_{12T4} &= Z_{T4AMV} + Z_{T4BMV} \\ Z_{12T3T4} &= Z_{12T3} \| Z_{12T4} = 0.5 \times Z_{12T3} \\ Z_{2G1} &= Z_{Q1t} + Z_{12T3T4} \end{aligned}$$

- Delta to Star conversion on buses 2, 3, 5 (Fig B)

$$Z_a = \frac{Z_{L1} \times Z_{L3}}{Z_{L1} + Z_{L3} + Z_{L4}}$$

$$Z_b = \frac{Z_{L1} \times Z_{L4}}{Z_{L1} + Z_{L3} + Z_{L4}}$$

$$Z_c = \frac{Z_{L3} \times Z_{L4}}{Z_{L1} + Z_{L3} + Z_{L4}}$$

- Star to delta conversion on buses N1, 3, 4 (Refer Fig D)

$$Z_d = \frac{Z_b \cdot Z_{S2} + Z_b \cdot Z_{L2} + Z_{S2} \cdot Z_{L2}}{Z_{S2}}$$

$$Z_e = \frac{Z_b \cdot Z_{S2} + Z_b \cdot Z_{L2} + Z_{S2} \cdot Z_{L2}}{Z_{L2}}$$

$$Z_f = \frac{Z_b \cdot Z_{S2} + Z_b \cdot Z_{L2} + Z_{S2} \cdot Z_{L2}}{Z_b}$$

(Fig F)

$$Z_g = \frac{Z_c \times Z_d}{Z_c + Z_d + Z_{L5}}$$

$$Z_h = \frac{Z_d \times Z_{L5}}{Z_c + Z_d + Z_{L5}}$$

$$Z_i = \frac{Z_c \times Z_{L5}}{Z_c + Z_d + Z_{L5}}$$

- Thevenin Impedance at Bus 4 (Fig G)

$$\begin{aligned} Z_1 &= Z_{2G1} + Z_a \\ Z_2 &= Z_1 \| Z_e \\ Z_3 &= Z_2 + Z_g \\ Z_4 &= Z_i + Z_{5G2} \\ Z_5 &= Z_3 \| Z_4 \\ Z_6 &= Z_5 + Z_h \\ Z_7 &= Z_6 \| Z_f \\ Z_{thev4} &= Z_7 \| Z_{S1} \end{aligned}$$

- Thevenin Impedance at Bus 5 (Fig G)

$$\begin{aligned} Z_8 &= Z_{S1} \| Z_f \\ Z_9 &= Z_8 + Z_h \\ Z_{10} &= Z_3 \| Z_9 \\ Z_{11} &= Z_i + Z_{10} \\ Z_{thev5} &= Z_{11} \| Z_{5G2} \end{aligned}$$

- Thevenin Impedance at Bus 2 (Fig G)

$$\begin{aligned} Z_{12} &= Z_4 \| Z_9 \\ Z_{13} &= Z_{12} + Z_g \\ Z_{14} &= Z_{13} \| Z_e \\ Z_{15} &= Z_a + Z_{14} \\ Z_{thev2} &= Z_{15} \| Z_{2G1} \end{aligned}$$

- Thevenin Impedance at Bus 6 (Fig G and Fig A)

- Thevenin Impedance at Bus 1 (Fig G and Fig A)

$$Z_{16} = Z_{15} + Z_{12T3T4}$$

$$Z_{17} = Z_{16} \times \frac{400^2}{120^2}$$

$$Z_{thev1} = Z_{17} \parallel Z_{Q1}$$

$$Z_{T5LV} = Z_{T5MV} \times \frac{10.5^2}{115^2}$$

$$Z_{21} = Z_{11} \parallel Z_{Q2}$$

$$Z_{21LV} = Z_{21} \times \frac{10.5^2}{115^2}$$

$$Z_{22} = Z_{21LV} + Z_{T5LV} \times 0.5$$

$$Z_{24} = Z_{M1} \parallel Z_{M2}$$

$$Z_{25} = Z_{L6} + Z_{24}$$

$$Z_{26} = Z_{G3} \parallel Z_{25}$$

$$Z_{thev6} = Z_{22} \parallel Z_{26}$$

3. 3-Phase Fault Calculations

(Refer file iec60909_testnetwork_calculations.py in PSS(R)E installation Example folder. Run this file from PSSE GUI as automation script. It geneartes results shown in following tables.)

```
IEC 60909-4:2000 Figure 16 (Page 121) 3-phase Fault Calculations with Network reduction Mon Jul  6 06:55:44 2020
NETWORK ELEMENT IMPEDANCES in OHMS (COMPARE this to TABLE 11, PP 127)
|---------- BASE FREQUENCY ------|   |---- METHOD C FREQ (fc/f=0.4)---|   |--- DC COMPONENT (fc/f=0.055)---|
zql     = 0.631933   + j 6.31933   | zql     = 0.631933   + j 2.52773   | zql     = 0.631933   + j 0.347563
zqlt    = 0.056874   + j 0.56874   | zqlt    = 0.056874   + j 0.227496  | zqlt    = 0.056874   + j 0.0312807
zq2     = 0.434454   + j 4.34454   | zq2     = 0.434454   + j 1.73782   | zq2     = 0.434454   + j 0.23895
zt3amv  = 0.045714   + j 8.09699   | zt3amv  = 0.045714   + j 3.2388    | zt3amv  = 0.045714   + j 0.445334
zt3bmv  = 0.053563   - j 0.079062  | zt3bmv  = 0.053563   - j 0.0316248 | zt3bmv  = 0.053563   - j 0.00434841
zt3cmv  = 0.408568   + j 20.292    | zt3cmv  = 0.408568   + j 8.11681   | zt3cmv  = 0.408568   + j 1.11606
zt5mv   = 2.04645    + j 49.0722   | zt5mv   = 2.04645    + j 19.6289   | zt5mv   = 2.04645    + j 2.69897
zsl     = 0.498795   + j 26.3367   | zsl     = 1.05374    + j 10.5347   | zsl     = 0.498795   + j 1.44852
zs2     = 1.20394    + j 35.3407   | zs2     = 1.64143    + j 14.1363   | zs2     = 1.20394    + j 1.94374
zg3     = 0.01779    + j 1.08962   | zg3     = 0.0762736  + j 0.435849  | zg3     = 0.01779    + j 0.0599293
zg3t    = 2.13396    + j 130.705   | zg3t    = 9.14937    + j 52.2821   | zg3t    = 2.13396    + j 7.18879
zml     = 0.341497   + j 3.41497   | zml     = 0.341497   + j 1.36599   | zml     = 0.341497   + j 0.187823
zmlt    = 40.9641    + j 409.641   | zmlt    = 40.9641    + j 163.856   | zmlt    = 40.9641    + j 22.5303
zm2     = 0.412137   + j 4.12137   | zm2     = 0.412137   + j 1.64855   | zm2     = 0.412137   + j 0.226675
zm2t    = 49.4377    + j 494.377   | zm2t    = 49.4377    + j 197.751   | zm2t    = 49.4377    + j 27.1907
zll     = 2.4        + j 7.8       | zll     = 2.4        + j 3.12      | zll     = 2.4        + j 0.429
zl2     = 1.2        + j 3.9       | zl2     = 1.2        + j 1.56      | zl2     = 1.2        + j 0.2145
zl3     = 0.3        + j 0.975     | zl3     = 0.3        + j 0.39      | zl3     = 0.3        + j 0.053625
zl4     = 0.96       + j 3.88      | zl4     = 0.96       + j 1.552     | zl4     = 0.96       + j 0.2134
zl5     = 1.8        + j 5.79      | zl5     = 1.8        + j 2.316     | zl5     = 1.8        + j 0.31845
zl6     = 0.082      + j 0.086     | zl6     = 0.082      + j 0.0344    | zl6     = 0.082      + j 0.00473
zl6t    = 9.83628    + j 10.3161   | zl6t    = 9.83628    + j 4.12644   | zl6t    = 9.83628    + j 0.567385
```

```
NETWORK REDUCTION  CALCULATION IMPEDANCES in OHMS
|---------- BASE FREQUENCY ------|   |  |---- METHOD C FREQ (fc/f=0.4)---|   |  |--- DC COMPONENT (fc/f=0.055)---|
z7g      = 22.4019    + j 224.019   |  z7g      = 22.4019    + j 89.6076    |  z7g      = 22.4019    + j 12.321
z6g1     = 32.2382    + j 234.335   |  z6g1     = 32.2382    + j 93.734     |  z6g1     = 32.2382    + j 12.8884
z6g2     = 4.98602    + j 84.1864   |  z6g2     = 7.8457     + j 33.7659    |  z6g2     = 2.76745    + j 5.92614
z56      = 1.02323    + j 24.5361   |  z56      = 1.02323    + j 9.81445    |  z56      = 1.02323    + j 1.34949
z5g1     = 6.00924    + j 108.722   |  z5g1     = 8.86893    + j 43.5804    |  z5g1     = 3.79068    + j 7.27563
z5g2     = 0.410563   + j 4.17791   |  z5g2     = 0.414788   + j 1.6713     |  z5g2     = 0.405976   + j 0.240458
z12t3    = 0.099277   + j 8.01793   |  z12t3    = 0.099277   + j 3.20717    |  z12t3    = 0.099277   + j 0.440986
z12t3t4  = 0.0496385  + j 4.00896   |  z12t3t4  = 0.0496385  + j 1.60359    |  z12t3t4  = 0.0496385  + j 0.220493
z2g1     = 0.106513   + j 4.5777    |  z2g1     = 0.106513   + j 1.83108    |  z2g1     = 0.106513   + j 0.251774
za       = 0.196067   + j 0.600759  |  za       = 0.196255   + j 0.240042   |  za       = 0.196697   + j 0.0329219
zb       = 0.635401   + j 2.39317   |  zb       = 0.633702   + j 0.959618   |  zb       = 0.629731   + j 0.132703
zc       = 0.0794251  + j 0.299146  |  zc       = 0.0792127  + j 0.119952   |  zc       = 0.0787164  + j 0.0165878
zd       = 1.97835    + j 6.54056   |  zd       = 1.97711    + j 2.58837    |  zd       = 2.10665    + j 0.144592
ze       = 1.73362    + j 59.1914   |  ze       = 2.63699    + j 23.4033    |  ze       = 2.43737    + j 3.1217
zf       = 6.65609    + j 97.3585   |  zf       = 7.38543    + j 39.625     |  zf       = 4.79676    + j 5.76803
zg       = 0.0406757  + j 0.154902  |  zg       = 0.0405918  + j 0.0617803  |  zg       = 0.0418009  + j 0.00659351
zh       = 0.923224   + j 2.99852   |  zh       = 0.922882   + j 1.19316    |  zh       = 0.954216   + j 0.118799
zi       = 0.037148   + j 0.137169  |  zi       = 0.0370208  + j 0.0553289  |  zi       = 0.0353733  + j 0.00952466
z1       = 0.302579   + j 5.17846   |  z1       = 0.302768   + j 2.07112    |  z1       = 0.303209   + j 0.284696
z2       = 0.267064   + j 4.76216   |  z2       = 0.27295    + j 1.90289    |  z2       = 0.270881   + j 0.261882
z3       = 0.30774    + j 4.91706   |  z3       = 0.313542   + j 1.96467    |  z3       = 0.312682   + j 0.268475
z4       = 0.447711   + j 4.31508   |  z4       = 0.451809   + j 1.72663    |  z4       = 0.44135    + j 0.249982
z5       = 0.19415    + j 2.29919   |  z5       = 0.196118   + j 0.921275   |  z5       = 0.185595   + j 0.133195
z6       = 1.11737    + j 5.29771   |  z6       = 1.119      + j 2.11443    |  z6       = 1.13981    + j 0.251994
z7       = 1.02237    + j 5.02928   |  z7       = 1.02523    + j 2.01821    |  z7       = 0.988813   + j 0.30835
z8       = 0.610257   + j 20.7376   |  z8       = 0.981686   + j 8.33216    |  z8       = 0.490876   + j 1.18643
z9       = 1.53348    + j 23.7362   |  z9       = 1.90457    + j 9.52532    |  z9       = 1.44509    + j 1.30523
z10      = 0.256341   + j 4.07327   |  z10      = 0.271099   + j 1.6291     |  z10      = 0.257102   + j 0.22272
z11      = 0.293489   + j 4.21044   |  z11      = 0.30812    + j 1.68443    |  z11      = 0.292475   + j 0.232244
z12      = 0.3568     + j 3.65202   |  z12      = 0.368489   + j 1.46237    |  z12      = 0.342185   + j 0.214765
z13      = 0.397475   + j 3.80693   |  z13      = 0.409081   + j 1.52415    |  z13      = 0.383985   + j 0.221358
z14      = 0.357181   + j 3.57802   |  z14      = 0.370203   + j 1.43292    |  z14      = 0.339773   + j 0.213493
z15      = 0.553247   + j 4.17878   |  z15      = 0.566459   + j 1.67296    |  z15      = 0.536469   + j 0.246415
z16      = 0.602886   + j 8.18775   |  z16      = 0.616097   + j 3.27655    |  z16      = 0.586108   + j 0.466908
z17      = 6.69873    + j 90.9749   |  z17      = 6.84552    + j 36.4061    |  z17      = 6.51231    + j 5.18786
zt5lv    = 0.0170602  + j 0.40909   |  zt5lv    = 0.0170602  + j 0.163636   |  zt5lv    = 0.0170602  + j 0.0224999
z21      = 0.180884   + j 2.13871   |  z21      = 0.184504   + j 0.856271   |  z21      = 0.176563   + j 0.120495
z21lv    = 0.00150794 + j 0.0178293 |  z21lv    = 0.00153811 + j 0.00713829 |  z21lv    = 0.00147191 + j 0.0010045
z22      = 0.0100381  + j 0.222374  |  z22      = 0.0100682  + j 0.0889563  |  z22      = 0.010002   + j 0.0122545
z24      = 0.186753   + j 1.86753   |  z24      = 0.186753   + j 0.747012   |  z24      = 0.186753   + j 0.102714
z25      = 0.268753   + j 1.95353   |  z25      = 0.268753   + j 0.781412   |  z25      = 0.268753   + j 0.107444
z26      = 0.041566   + j 0.701818  |  z26      = 0.0654056  + j 0.281489   |  z26      = 0.023071   + j 0.0494032
z27      = 0.00743428 + j 0.184705  |  z27      = 0.00912939 + j 0.0739166  |  z27      = 0.00727729 + j 0.0105109
z28      = 0.0894343  + j 0.270705  |  z28      = 0.0911294  + j 0.108317   |  z28      = 0.0892773  + j 0.0152409
```

```
Thevenin Impedance in OHMS calculated with NETWORK REDUCTION (R+jX, X/R ratio)
|BUS| |---------- BASE FREQUENCY --------|    |   |----- METHOD C FREQ (fc/f=0.4)----|    |   |---- DC COMPONENT (fc/f=0.055)----|
  1    0.58075    + j 5.90914   , 10.175         0.581294   + j 2.36416   , 10.1676        0.577802   + j 0.328019  , 10.3218
  2    0.174972   + j 2.19103   , 12.5222        0.175786   + j 0.89077   , 12.6684        0.116706   + j 0.160461  , 24.9985
  4    0.732689   + j 4.24215   , 5.78984        0.743174   + j 1.73075   , 5.82216        0.538887   + j 0.429792  , 14.501
  5    0.176207   + j 2.09748   , 11.9035        0.180754   + j 0.839774  , 11.6148        0.171157   + j 0.119847  , 12.7312
  6    0.00819474 + j 0.168874  , 20.6076        0.00955065 + j 0.0677631 , 17.7378        0.00725323 + j 0.00996696, 24.9844
  7    0.0710396  + j 0.237798  , 3.3474         0.0714299  + j 0.0979088 , 3.42674        0.0620099  + j 0.0170342 , 4.99455
```

METHOD	BUS	I"k	K ip(50)	ip(50)	K ip(20)	ip(20)	Ib dc
CALCULATED	1	40.6447	1.7498	100.5766	1.7496	100.5677	2.7396
PSS(R)E		40.6447		100.5766		100.5676	2.7396
STANDARD		40.6447	1.7498	100.5766	1.7496	100.5677	
CALCULATED	2	31.7831	1.7912	80.5120	1.7934	80.6079	12.7917
PSS(R)E		31.7830		80.5119		80.6079	12.7917
STANDARD		31.7831	1.7982	80.8249	1.7934	80.6079	
CALCULATED	4	16.2277	1.6037	36.8041	1.6054	36.8427	2.6296
PSS(R)E		16.2277		36.8041		36.8427	2.6296
STANDARD		16.2277	1.6037	36.8041	1.6054	36.8427	
CALCULATED	5	33.1894	1.7817	83.6266	1.7769	83.4033	3.9796
PSS(R)E		33.1894		83.6265		83.4033	3.9796
STANDARD		33.1894	1.7817	83.6266	1.7769	83.4033	
CALCULATED	6	37.5629	1.8672	99.1910	1.8475	98.1434	15.1071
PSS(R)E		37.5628		99.1908		98.1432	15.1072
STANDARD		37.5629	1.8672	99.1910	1.8475	98.1434	
CALCULATED	7	25.5895	1.6329	59.0944	1.4283	51.6899	0.0671
PSS(R)E		25.5894		59.0943		51.6898	0.0671
STANDARD		25.5895	1.6329	59.0944	1.4283	51.6899	

11.11. Modeling Metal Oxide Varistors (MOV) in Short Circuit Calculations

References:

1. Daniel L. Goldsworthy, "A linearized model for MOV-protected series capacitors," IEEE Transactions on Power Systems, Vol. PWRS-2, No. 4, pp 953-958, November 1987.

2. Marc Coursol, Chinh T. Nguyen, Rene Lord, Xuan-Dai Do, “Modeling of MOV Protected Series Capacitors in Short Circuit Studies”, IEEE Transactions on Power Delivery , Vol.8, No.1, pp 448-453, January 1993.

11.11.1. Introduction

A typical MOV-protected series capacitor arrangement is shown in Figure 11.113, “Three Phase MOV protected series capacitor branch”. The MOV protection is connected directly in parallel with the series capacitor and performs its function by holding the maximum capacitor voltage within the designed protective level. MOV conduction normally occurs only during faults because the capacitor protective level is usually specified above the maximum voltages expected during overload or swing conditions.

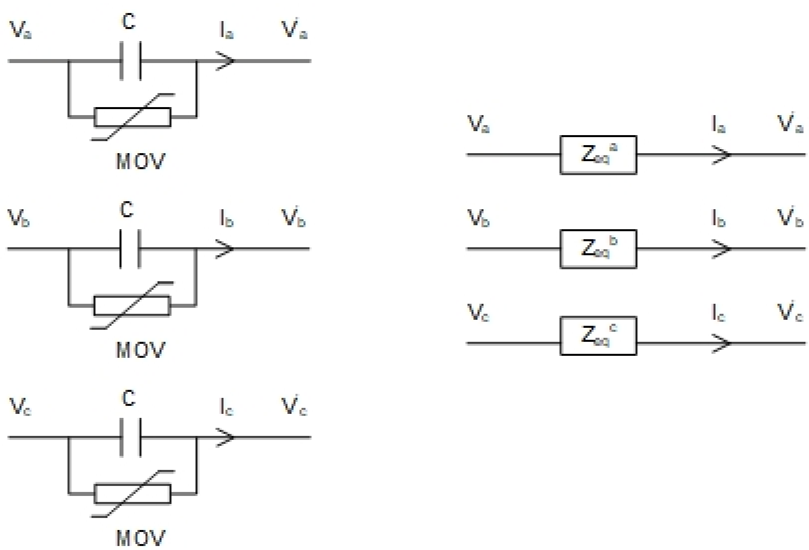


Figure 11.113. Three Phase MOV protected series capacitor branch

Notations:

Ir = capacitor bank rated current

Ipr = protective level current

Xco = reactance of the capacitor bank

Vpk = peak capacitor volatge,

$$V_{pk} = \sqrt{2} I_{pr} X_{co}$$

Ibrn = actual current flowing through the capacitor branch

Ipu = normalized current flowing through the capacitor branch,

$$I_{pu} = I_{brn} / I_{pr}$$

Ipr determines the protective level voltage and is specified as a multiple of the capacitor bank rated current. It is typically 2.0 to 2.5 of Ir.

The MOV protection is designed to hold the capacitor voltage at or below this peak value even for the largest available system current, Imax.

11.12. Linearized Model of MOV

For

$$(I_{pu} > 0.98)$$

$$\begin{aligned} R_{ceq} &= X_{CO} 0.0745 + 0.49 e^{-0.243 I_{pu}} - 35.0 e^{-5.0 I_{pu}} - 0.6 e^{-1.4 I_{pu}} \\ X_{ceq} &= X_{CO}\left(0.1010 - 0.005749 I_{pu} + 2.088 e^{-0.8566 I_{pu}}\right) \end{aligned} \qquad (1)$$

The equivalent impedance of MOV-series capacitor branch is then defined as:

$$\begin{aligned} Z_{eq} &= -jX_{co} \qquad \text{for } I_{pu} \le 0.98 \qquad (2a) \\ Z_{eq} &= R_{ceq} - jX_{ceq} \qquad \text{for } I_{pu} > 0.98 \qquad (2b) \end{aligned}$$

11.13. MOV-Series Capacitor branch representation in Sequence Components

The linearized MOV model gives different phase impedance values during unbalanced faults since the currents flowing through each phase are different. The phase impedance matrix for the MOV-protected series capacitor branch shown in Figure 11.113, “Three Phase MOV protected series capacitor branch” is:

$$Z_{eq}^{abc} = \begin{bmatrix} Z_{eq}^{a} & 0 & 0 \\ 0 & Z_{eq}^{b} & 0 \\ 0 & 0 & Z_{eq}^{c} \end{bmatrix} \qquad (3)$$

The voltage drop through a typical MOV-capacitor branch shown in Figure 11.113, “Three Phase MOV protected series capacitor branch” is given by:

$$\begin{bmatrix} V_{aa'} \\ V_{bb'} \\ V_{cc'} \end{bmatrix} = \begin{bmatrix} Z_{eq}^{a} & 0 & 0 \\ 0 & Z_{eq}^{b} & 0 \\ 0 & 0 & Z_{eq}^{c} \end{bmatrix} \begin{bmatrix} I_a \\ I_b \\ I_c \end{bmatrix} \qquad (4)$$

Note: It is assumed that there is no mutual coupling between three impedances in Eqn. (4).

Converting Eqn. (4) in terms of the symmetrical components of the voltage and current:

$$\begin{bmatrix} 1 & 1 & 1 \\ 1 & a^2 & a \\ 1 & a & a^2 \end{bmatrix} \begin{bmatrix} V_{aa'0} \\ V_{aa'1} \\ V_{aa'2} \end{bmatrix} = \begin{bmatrix} Z_{eq}^{a} & 0 & 0 \\ 0 & Z_{eq}^{b} & 0 \\ 0 & 0 & Z_{eq}^{c} \end{bmatrix} \begin{bmatrix} 1 & 1 & 1 \\ 1 & a^2 & a \\ 1 & a & a^2 \end{bmatrix} \begin{bmatrix} I_0 \\ I_1 \\ I_2 \end{bmatrix} \qquad (5)$$

$$\begin{bmatrix} V_{aa'0} \\ V_{aa'1} \\ V_{aa'2} \end{bmatrix} = \frac{1}{3}\begin{bmatrix} 1 & 1 & 1 \\ 1 & a & a^2 \\ 1 & a^2 & a \end{bmatrix}\begin{bmatrix} Z_{eq}{}^{a} & 0 & 0 \\ 0 & Z_{eq}{}^{b} & 0 \\ 0 & 0 & Z_{eq}{}^{c} \end{bmatrix}\begin{bmatrix} 1 & 1 & 1 \\ 1 & a^2 & a \\ 1 & a & a^2 \end{bmatrix}\begin{bmatrix} I_0 \\ I_1 \\ I_2 \end{bmatrix} \qquad (6)$$

$$\begin{bmatrix} V_{aa'0} \\ V_{aa'1} \\ V_{aa'2} \end{bmatrix} = \frac{1}{3}\begin{bmatrix} 1 & 1 & 1 \\ 1 & a & a^2 \\ 1 & a^2 & a \end{bmatrix}\begin{bmatrix} Z_{eq}{}^{a} & Z_{eq}{}^{a} & Z_{eq}{}^{a} \\ Z_{eq}{}^{b} & a^2Z_{eq}{}^{b} & aZ_{eq}{}^{b} \\ Z_{eq}{}^{c} & aZ_{eq}{}^{c} & a^2Z_{eq}{}^{c} \end{bmatrix}\begin{bmatrix} I_0 \\ I_1 \\ I_2 \end{bmatrix} \qquad (7)$$

$$\begin{bmatrix} V_{aa'0} \\ V_{aa'1} \\ V_{aa'2} \end{bmatrix} = \frac{1}{3}\begin{bmatrix} Z_h & Z_p & Z_n \\ Z_n & Z_h & Z_p \\ Z_p & Z_n & Z_h \end{bmatrix}\begin{bmatrix} I_0 \\ I_1 \\ I_2 \end{bmatrix} \qquad (8)$$

where:

$$Z_h = \frac{1}{3}(Z_{eq}{}^{a} + Z_{eq}{}^{b} + Z_{eq}{}^{c}) \qquad (9a)$$

$$Z_p = \frac{1}{3}(Z_{eq}{}^{a} + a^2Z_{eq}{}^{b} + aZ_{eq}{}^{c}) \qquad (9b)$$

$$Z_n = \frac{1}{3}(Z_{eq}{}^{a} + aZ_{eq}{}^{b} + a^2Z_{eq}{}^{c}) \qquad (9c)$$

$$a = 1\angle 120^0 = -0.5 + j0.866 = e^{j2\pi/3}$$

From Eqn. (8), the effective sequence impedances of MOV-series capacitor branch because of MOV conduction can be determined as:

$$
\begin{aligned}
\bar{Z}_0 &= \frac{V_{aa'0}}{I_0} = \frac{1}{3}\left[Z_h + Z_p\frac{I_1}{I_0} + Z_n\frac{I_2}{I_0}\right] \\
\bar{Z}_1 &= \frac{V_{aa'1}}{I_1} = \frac{1}{3}\left[Z_h + Z_n\frac{I_0}{I_1} + Z_p\frac{I_2}{I_1}\right] \\
\bar{Z}_2 &= \frac{V_{aa'2}}{I_2} = \frac{1}{3}\left[Z_h + Z_p\frac{I_0}{I_2} + Z_n\frac{I_1}{I_2}\right]
\end{aligned}
\qquad (10)
$$

Eqn. (8) shows that at the branches where MOVs are conducting unequally, there is coupling between sequences.

Therefore, in unsymmetrical fault calculations, MOV-series capacitor branch is represented by self impedances and intersequence couplings as in Eqn. (8) and Figure 11.114, “Equivalent sequence network for MOV protected series capacitor branch”.

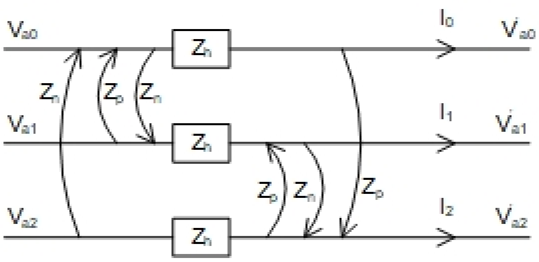


Figure 11.114. Equivalent sequence network for MOV protected series capacitor branch

11.14. PSSE Implementation of MOV

1. Assume all MOVs are not conducting. The impedance of all MOV-series capacitor branches is as in Eqn. (2a).

2. Apply specified fault.

3. Calculate branch currents

   $$(I_0, I_1, I_2)$$

   and

   $$(I_a, I_b, I_c)$$

   flowing through all MOV-series capacitor branches.

4. Calculate

   $$I_{pu}^{a}, I_{pu}^{b}, I_{pu}^{c}$$

   .for each MOV-series capacitor branch and each phase in that branch as below.

   $$I_{pu(n+1)} = I_{pu(n)} + \alpha\left(\frac{I_{brn}}{I_{pr}} - I_{pu(n)}\right) \qquad \text{for } (\alpha < 1.0)$$

5. Now for each

   $$(I_{pu} > 0.98)$$

   , calculate that phase impedance

   $$Z_{eq}^{a}, Z_{eq}^{b}, Z_{eq}^{c}$$

   as in Eqn. (2b)

6. Using

   $$Z_{eq}$$

from Step (5), calculate

$$(\bar{Z}_0, \bar{Z}_1, \bar{Z}_2)$$

using Eqn. (10) for each MOV-series capacitor branch.

7. Update network Ymatrix with

$$(\bar{Z}_0, \bar{Z}_1, \bar{Z}_2)$$

from Step(6).

8. Calculate branch currents as in Step (3).

9. Stop the iteration process if change in all MOV-series capacitor branch currents is less than a given tolerance or exceeds number of iteration limits, else go to Step (4).

Note: PSSE uses a convergence acceleration factor

$$\alpha = 0.3$$

, tolerance = 0.01 and maximum number of iterations = 20, as default values.

11.15. Modeling Non Conventional Source Fault Contribution (NCSFC)in Short Circuit Calculations

The fault contribution from non-conventional sources like Type 3 and Type 4 Wind Generators and Photo Voltaic Sources is very much dependent on the voltage source converters used, and is fundamentally different from conventional synchronous fault contribution. In most of the machines cases, the converter design and control determines the fault contribution. This fault current contribution is modeled as shown below.

Figure 11.115. Non-conventional Source Fault Contribution Characteristics

- Time dependent fault current contribution

  A source injects additional constant fault current and is independent of its terminal voltage. The amount of fault current contribution is determined from its characteristics and time of fault clearance (breaker contact parting time).

This source is represented as a voltage source behind impedance in positive sequence. If the source contributes to negative sequence currents, then it will be represented with equivalent negative sequence impedance otherwise it will be open in negative sequence. This source will be open in zero sequence. This fault current contribution and its sequence network model is shown in Figure 11.116, “Non-conventional Source Sequence Network”

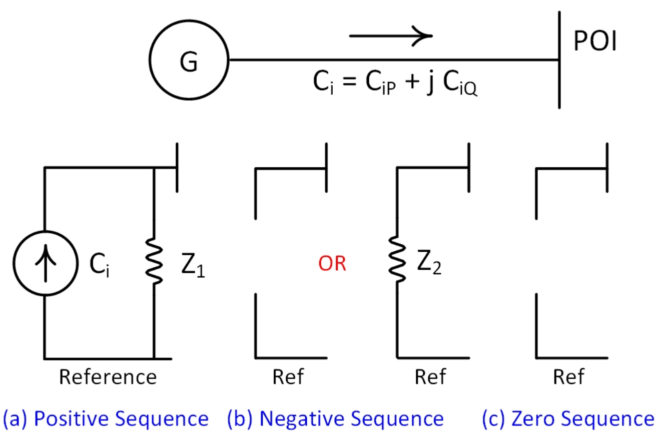


Figure 11.116. Non-conventional Source Sequence Network

Non-conventional machine sequence impedances and fault current contributions are calculated as below.

- Equivalent Source Impedance

  The pu positive sequence (Z_1), and negative sequence (Z_2) impedance on machine MVA (MBASE) and bus nominal voltage base is calculated as below. These are then used to represent the machine in the sequence networks.

$$Z_1 = \frac{1}{C_{iP} - jC_{iQ}}$$

$Z_2 = Z_1$

$Z_0 = \infty$

- Fault Current Contribution

  The contribution to the fault by this source is calculated as below.

  This is a rated contribution and is independent of machine pre and/or post fault bus voltage.

  $$I_F = \frac{\mathrm{MBASE}}{\sqrt{3} \times V_R} \left(C_{iP} - jC_{iQ}\right)$$

  where:

  MBASE is the machine rated MVA specified on generator power flow data record.

  V_R is the machine rated voltage.

Application Notes

- Time Dependent Characteristics

  Generally T_1 would be 0.0, and then C_{1P} and C_{1Q} would provide momentary fault contribution from this source. Activities ASCC and SCMU use C_{1P} and C_{1Q} values.

  The activity IECS calculates the fault currents at breaker contact parting time. So the C_{iP} and C_{iQ} values at breaker contact parting time are used. Also in the activity IECS, sequence impedances of Wind/PV type machine can be defined in IEC data file as per IEC 60909 standard. If the machine has Wind/PV data specified in IEC data file, NCSFC machine data for that machine is ignored.

- The activities ANSI and BKDY does not yet model machine as NCSFC machine even when NSCFC data is specified.

Chapter 12
GIC Calculations

12.1. Transmission System Network Model for GIC Calculations

The Auroral Electrojets due to Geomagnetic Disturbance (GMD) causes short term variations in the earth's magnetic field. The changes in earth's magnetic field create electric field over the surface of the affected region which in turn induces voltages in the high voltage transmission lines. The induced voltages in transmission lines cause Geomagnetically Induced Currents (GICs) to flow if there is a closed path for currents to circulate. This path is typically provided by transformer and shunt grounding connections [1, 2].

The GICs are often described as being quasi-direct current (dc). Their frequency variation is dependent on the time variation of the electric field that drives them. In general GICs have low frequency below 1 Hz. Therefore, GICs flowing in power system grid are calculated by representing entire power system network by its dc resistance with following simplifications [1, 2].

- The transmission lines are represented by their dc resistances in series with induced dc voltage.
- The transmission line reactors and charging are ignored.
- The series compensated transmission line block GICs flow and hence are ignored.
- The windings of two and three winding transformers that have ground path are modeled.
- The common winding if it is grounded and series windings of auto-transformer are modeled.
- The shunt reactors if grounded are considered.
- The equivalent station grounding resistance is considered.

As described in [3] and illustrated in Figure 12.1, “Power System Network Model in GIC Calculations”, the Induced Voltages in series with Transmission Lines method is implemented by activity GIC.

Figure 12.1. Power System Network Model in GIC Calculations

Notations:

- GIC induced voltages on a transmission lines:

  V1, V2, V3 and V4

- Transmission Line dc resistances:

  Rline1, Rline2, Rline3, Rline4

- Transformer Winding dc resistances:

  Rtrn1-w1, Rtrn1-w2, Rtrn2-w2

- Shunt dc resistances:

  Rsh2, Rsh3

- Substation ground dc resistances:

  Rgrd2, Rgrd3, Rgrd4

- Substations:

  Sub1 (ungrounded switching station), Sub2, Sub3, Sub4

12.2. Transmission Line Distance Calculation

As shown in Figure 12.2, “Transmission Line Location Geographical Coordinates”, a transmission line from substation A to substation B is described by its geographical coordinates (latitude and longitude) as (LatA, LonA) degrees and (LatB and LonB) degrees.

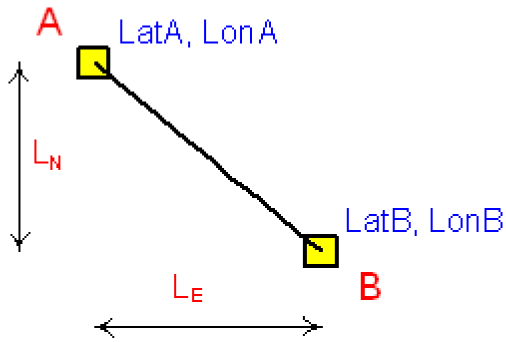


Figure 12.2. Transmission Line Location Geographical Coordinates

Assuming spherical earth model and parameters of the WGS84 earth model, transmission line Northward (L_N) and Eastward (L_E) distances in km are given by following equations (1) and (2) [1, 2, 5].

$$L_N = (111.133 - 0.56\cos(2\emptyset)) * \Delta lat \qquad (1)$$

$$L_E = (111.5065 - 0.1872\cos(2\emptyset)) * cos\emptyset * \Delta long \qquad (2)$$

$$\emptyset = \frac{LatA+LatB}{2}, \qquad \Delta lat = LatA - LatB, \qquad \Delta long = longA - longB$$

12.3. Transmission Line Induced Voltage

The induced voltage in the transmission line is computed by integrating the geoelectric field along the route of the transmission line, as in equation (3) [1, 2, 5].

$$V = \oint_R \vec{E}\,\overrightarrow{dl} \qquad (3)$$

where

$\vec{E}$

is the electric field vector at the location of the transmission line, the route of the line between substations A and B is denoted by R, and

$\overrightarrow{dl}$

is the incremental line segment length including direction.

Three different GMD events are modeled.

12.3.1. Transmission Line Induced Voltage for Uniform Geoelectric Field

The effect of GMD is specified in terms of uniform geoelectric field (E) in V/km and its direction (θ) in degrees. This geoelectric field is assumed to be constant for the entire region of the power system network. The induced voltage is given by equation (4) [1, 2, 5].

$$V = E_N L_N + E_E L_E \qquad (4)$$

$$E_N = E\cos\theta \qquad (5)$$

$$E_E = E\sin\theta \qquad (6)$$

where:

E_N is the Northward electric field (V/km)

E_E is the Eastward electric field (V/km)

L_N is the Northward distance (km)

L_E is the Eastward distance (km)

E is the geoelectric field strength (V/km)

θ is the geoelectric field direction in degrees (0 degrees for North, positive East and negative West)

12.3.2. Transmission Line Induced Voltage for Benchmark GMD Event

The Benchmark GMD event described in [6] takes into consideration the known characteristics of a severe GMD event and provides reference geoelectric field. This is done to provide uniform evaluation criteria for assessing system performance during low probability GMD event.

A reference geoelectric field of 8 V/km defined in benchmark GMD event [6, 7] is modified to account for the effect of local geomagnetic latitude and earth conductivity using equation (7).

$$E = 8 \times \alpha \times \beta \qquad (\mathrm{V/km}) \qquad (7)$$

where α is the scaling factor to account local geomagnetic latitude, and β is a scaling factor to account for the local earth conductivity structure.

Then using equations (4), (5) and (6) voltage induced in the transmission line is computed.

The substation location data is provided in terms of geographical coordinates. However, alpha scaling factors in terms of geomagnetic coordinates. Therefore, GIC activity "Benchmark Year" option is used to convert substation geographical coordinates to geomagnetic coordinates. Then the alpha scaling factor to account for local geomagnetic latitude is determined from table below [6]. For a transmission line, higher of from and to end geomagnetic latitudes is considered which gives conservative value of alpha.

Table 12.1. Geomagnetic Latitude Alpha Scaling Factors for GIC Benchmark Event Calculations

Geomagnetic Latitude (Degrees)	Alpha Scaling Factor(α)
≤40	0.1
45	0.2
50	0.3
55	0.6
56	0.6
57	0.7
58	0.8
59	0.9
≥ 60	1.0

The substation earth model name and following table gives beta scaling factor below [6].

Table 12.2. Earth Model Beta Scaling Factors for GIC Benchmark Event Calculations

USGS Earth Model Name	Beta Scaling Factor (β)
AK1A	0.56

USGS Earth Model Name	Beta Scaling Factor (β)
AK1B	0.56
AP1	0.33
AP2	0.82
BR1	0.22
CL1	0.76
CO1	0.27
CP1	0.81
CP2	0.95
CS1	0.41
IP1	0.94
IP2	0.28
IP3	0.93
IP4	0.41
NE1	0.81
PB1	0.62
PB2	0.46
PT1	1.17
SL1	0.53
SU1	0.93
BC	0.67
PRAIRIES	0.96
SHIELD	1.0
ATLANTIC	0.79
User defined in GIC data file	Provided in GIC data file

12.3.3. Transmission Line Induced Voltage for Non-Uniform Geoelectric Field

The GMD caused magnetic field variations are not uniform over the region of power system. Also the earth conductivity varies from region to region [2]. This results in power system experiencing non-uniform geoelectric field. As described in [2] and [4], the complex image method is used to compute the geoelectric field that will be in series the transmission line.

Complex Skin Depth Calculations [2, 4]

Figure 12.3, "Dimensional Layered Earth Conductivity Model" shows one-dimensional (1-D) layers earth conductivity model. This model ignores lateral variations in conductivity but considers variation of conductivity with depth.

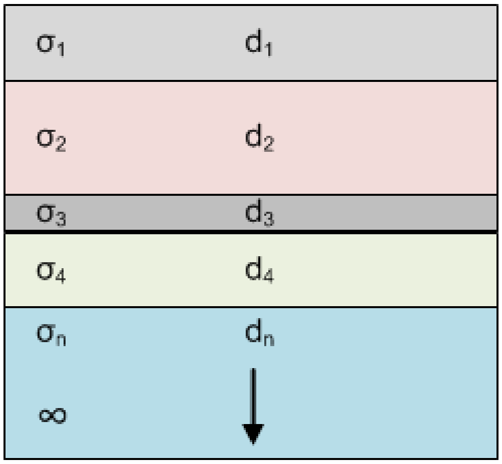


Figure 12.3. Dimensional Layered Earth Conductivity Model

The relations between magnetic fields (H) and electric fields (E) in the Earth depend on the angular frequency, ω = 2 π f, the conductivities, σ n, of each layer and the magnetic permeability. The free space magnetic permeability, μ 0 = 4 π .10-7 H/m is assumed. The magnetic and electric fields are assumed to have a time dependence of the form ej ω t.

If the earth is assumed to have a uniform conductivity the surface impedance, ZS, is given by:

$$Z_S(\omega) = \frac{E(\omega)}{H(\omega)} = \sqrt{\frac{j\omega\mu_0}{\sigma}}$$

The variation of conductivity with depth within the Earth can be taken into account by using a multi-layer model with different conductivities, ?n, for each layer. The fields in each layer can be determined by its propagation constant (kn) and characteristic impedance (?n) of the layer given by:

$$k_n = \sqrt{j\omega\mu_0\sigma_n}$$

$$\eta_n = \sqrt{\frac{j\omega\mu_0}{\sigma_n}}$$

The impedance at the surface can be calculated using recursive relations. The impedance at the surface of the bottom half-space is given by the characteristic impedance of that layer.

$$Z_N = \sqrt{\frac{j\omega\mu_0}{\sigma_N}}$$

The impedance at the surface of successive layers up to the surface is given by:

$$Z_n = \left(\frac{1+\alpha_n}{1-\alpha_n}\right)\eta_n$$

where:

$$\alpha_n = \left(\frac{Z_{n+1}-\eta_n}{Z_{n+1}+\eta_n}\right)e^{-2k_n d_n}$$

where dn is the depth of the layer.

The top layer Zn is the surface impedance ZS for the layered earth model.

This surface impedance value, Zs, can be used to calculate the complex skin depth, p, as:

$$p = \frac{Z_s}{j\omega\mu_0} \qquad (8)$$

Electrojet Calculations [2, 4]

The magnetic and electric fields produced by the auroral electrojet can be calculated using the complex image method.

Figure 12.4, “Electrojet Calculations using Complex Image Method” shows distances to an external line current at a height, h and an image current at a complex depth h+2p from a location on the Earth's surface.

The total variation fields at the Earth's surface are due to the field of the external source plus the field due to the currents induced in the Earth. The magnetic and geoelectric fields are then given by the source and image currents and their distances from the location on the surface as shown in Figure 12.4, “Electrojet Calculations using Complex Image Method”.

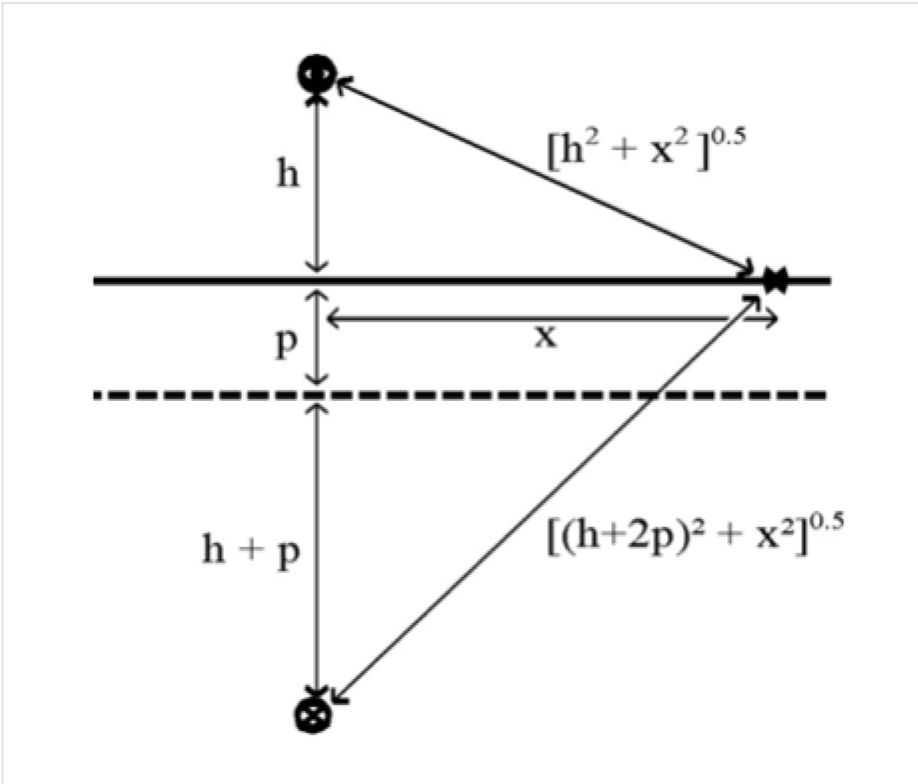


Figure 12.4. Electrojet Calculations using Complex Image Method

The geoelectric fields at horizontal distance, x, from the source current are then given by [2, 4]:

$$E_y = -\frac{j\omega\mu_0 I}{2\pi} ln\left[\frac{\sqrt{(h+a+2p)^2 + x^2}}{\sqrt{(h+a)^2 + x^2}}\right] \quad (9)$$

$$x = (111.133 - 0.56\cos(2\emptyset)) * \Delta lat \quad (10)$$

$$\emptyset = \frac{LatA+LatB}{2}, \qquad \Delta lat = LatA - LatB,$$

where:

I =	Electrojet Current Amplitude
a =	Electrojet Current density, Cauchy distribution half-width
ω =	Electrojet Angular frequency = 1/(2 π *period of variation)
h =	Electrojet Height of current

x =	Distance between the transmission line and center of the electrojet
p =	Earth Model Complex Skin depth
LatA =	Latitude of center of electrojet
LatB =	Latitude of transmission line

These geoelectric fields provided by equation (9) are used to calculate transmission line induced voltages as in equation (11).

$$V = E_y L_E \qquad (11)$$

12.4. Earth Conductivity Models6

Following one dimensional earth conductivity models defined by United States Geological Survey (USGS) (http://geomag.usgs.gov/conductivity/) are added as standard earth conductivity models to GIC activity.

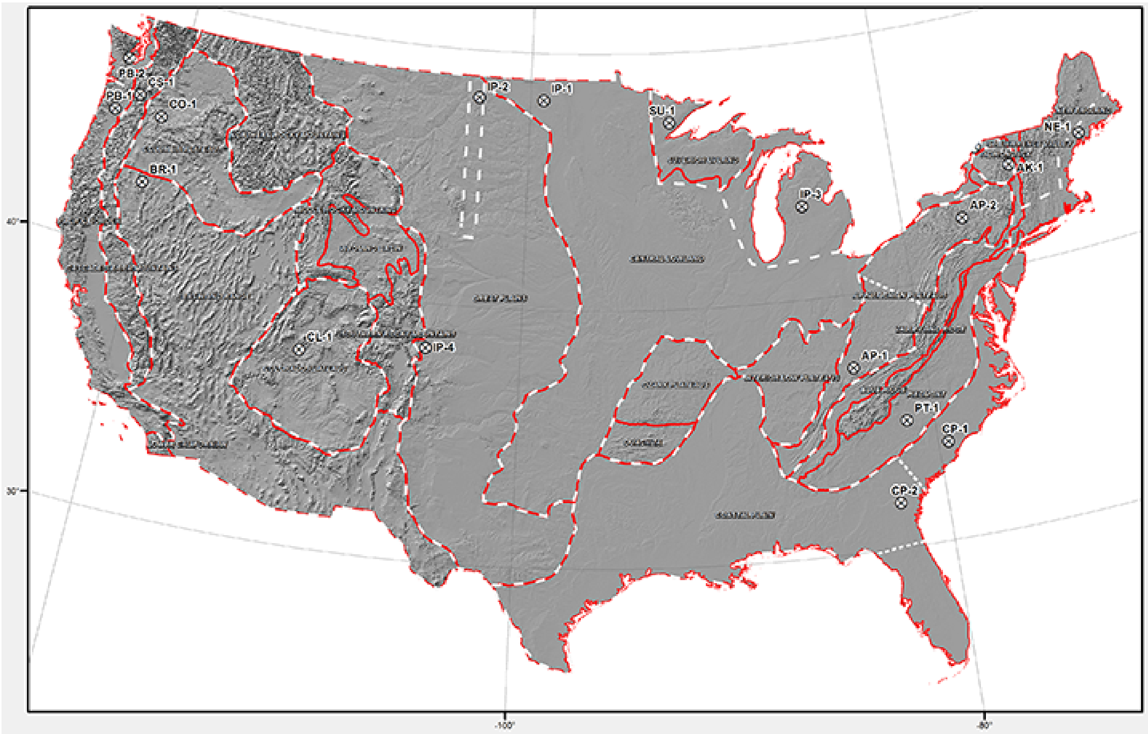


Figure 12.5. US Earth Conductivity Regions

Name	Description
AK1A	Adirondack Mountains-1A
AP1	Appalachian Plateaus
BR1	Northewest Basin and Range
CO1	Columbia Plateau
CP2	Coastal Plain (Georgia)
IP1	Interior Plains (North Dakota)
IP3	Interior Plains (Michigan)
NE1	New England
PB2	Pacific Border (Puget Lowlands)
SL1	St. Lawrence Lowlands
AK1B	Adirondack Mountains-1B
AP2	Northern Appalachian Plateaus
CL1	Colorado Plateau
CP1	Coastal Plain (South Carolina)
CS1	Cascade-Sierra Mountains

Name	Description
IP2	Interior Plains
IP4	Interior Plains (Great Plains)
PB1	Pacific Border (Willamette Valley)
PT1	Piedmont
SU1	Superior Upland

Following one dimensional earth conductivity models defined by Natural Resources Canada are added as standard earth conductivity models to GIC activity.

Figure 12.6. Canada Earth Conductivity Regions

Name	Description
BC	British Columbia (BC)
PRARIES	Alberta (AB), Saskatchewan (SK), Manitoba (MB)
SHIELD	Ontario (ON), Quebec (QC)
ATLANTIC	Atlantic Canada

Additionally user can specify earth conductivity model in GIC data file.

12.5. Effective GIC

The effective GIC (*Ieff*) flow in a transformer due to GICs flowing in one or more of its winding is dependent upon transformer type. Figure 12.7, "Effective GIC Calculation for Various Transformers (a) Two Winding (b) Two Winding Auto (c) Three Winding (d) Three Winding Auto" illustrates the GIC flows in transformer windings for various transformer configurations.

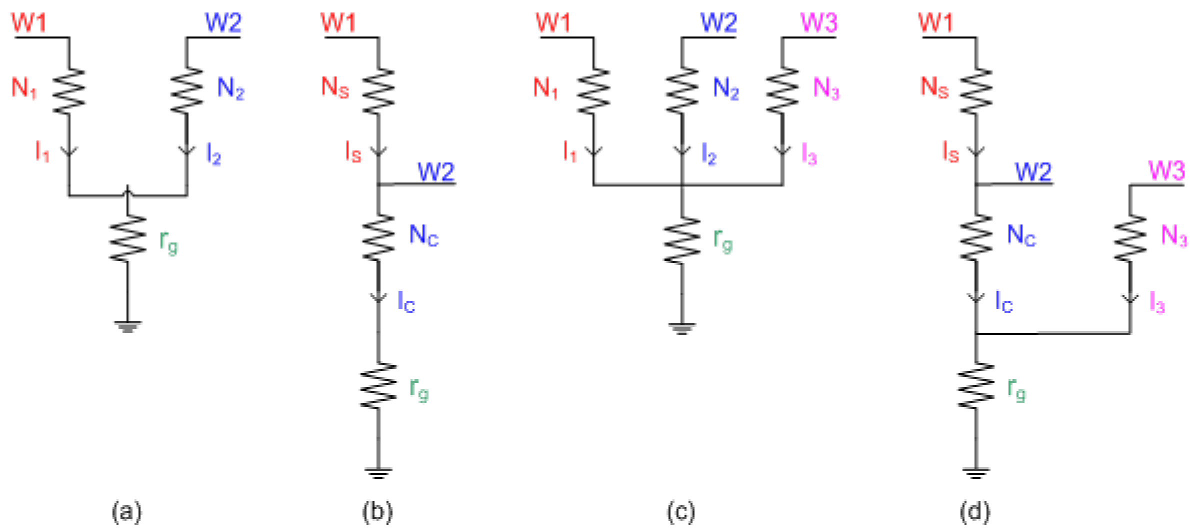


Figure 12.7. Effective GIC Calculation for Various Transformers (a) Two Winding (b) Two Winding Auto (c) Three Winding (d) Three Winding Auto

Assuming *Ieff* is represented on the winding 1 side of a transformer, this can be derived for various transformer types as below.

$$I_1N_1 + I_2N_2 = I_{eff}N_1$$
$$N = \frac{N_1}{N_2} = \frac{V_1}{V_2}$$
$$I_{eff} = \left|\frac{NI_1 + I_2}{N}\right| \qquad (12a)$$

(a) Two Winding Transformers

$$I_SN_S + I_CN_C = I_{eff}(N_S + N_C)$$
$$N = \frac{N_S + N_C}{N_C} = \frac{V_1}{V_2}$$
$$I_{eff} = \left|\frac{(N-1)I_S + I_C}{N}\right| \qquad (12b)$$

(b) Two Winding Auto Transformers

$$I_1N_1 + I_2N_2 = I_{eff12}N_1$$
$$N_{12} = \frac{N_1}{N_2} = \frac{V_1}{V_2}$$
$$I_{eff12} = \frac{N_{12}I_1 + I_2}{N_{12}}$$
$$I_{eff12}N_1 + I_3N_3 = I_{eff}N_1$$
$$N_{13} = \frac{N_1}{N_3} = \frac{V_1}{V_3}$$
$$I_{eff} = \left|\frac{N_{13}I_{eff12} + I_3}{N_{13}}\right| \qquad (12c)$$

(c) Three Winding Transformers

$$I_SN_S + I_CN_C = I_{eff}(N_S + N_C)$$
$$N_{12} = \frac{N_S + N_C}{N_C} = \frac{V_1}{V_2}$$
$$I_{eff12} = \frac{(N_{12}-1)I_S + I_C}{N_{12}}$$
$$I_{eff12}N_1 + I_3N_3 = I_{eff}N_1$$
$$N_1 = N_S + N_C$$
$$N_{13} = \frac{N_1}{N_3} = \frac{V_1}{V_3}$$
$$I_{eff} = \left|\frac{N_{13}I_{eff12} + I_3}{N_{13}}\right| \qquad (12d)$$

(d) Three Winding Auto Transformers

In the above, the ampere per phase GIC flow in various windings is identified as: I_1=Winding 1, I_2=Winding 2, I_3=Winding 3, I_C=Auto Transformer Common Winding, and I_s= Auto Transformer Series Winding.

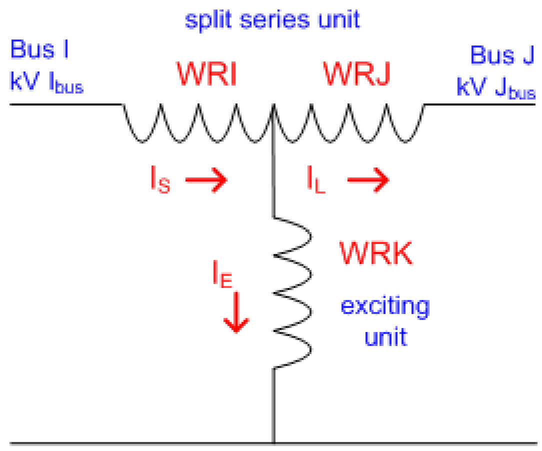


Figure 12.8. Effective GIC Calculation for Symmetric Phase Shifting Transformer

For symmetric phase shifting transformer represented as T-model is GIC Calculations, exciting unit and series unit are actually two transformers, so effective GIC is considered as:

$$I_{eff} = |I_S| + |I_E| \qquad (12e)$$

12.6. GIC to MVAR Calculations

Using Kfactors

One of the effects of the GICs flowing in transformer windings is that the transformer is subjected to half-cycle saturation resulting in increased reactive power (Mvar) losses in these equipments [1, 2]. Using GIC to Mvar scaling factors transformer reactive power losses are calculated.

When a specific K_{factor} value is provided for a transformer (in GIC data file), equation (13) is used to calculate transformer reactive power losses.

$$Q = I_{eff} \times K_{factor} \qquad (13)$$

where K_{factor} is Mvar/ampere scaling factor.

A generic scaling factor value [8] based on the transformer type is obtained as in Table 12.3, "Generic GIC to Mvar Scaling Factors". Then equation (14) is used to calculate reactive power losses.

$$Q = I_{eff} \times K_{factor} \times \frac{V_H}{500} \qquad (14)$$

where VH is Transformer Windings highest voltage in kV.

Table 12.3. Generic GIC to Mvar Scaling Factors

If Cores value is provided in GIC data file, Kfactor is determined as below		
Core Design	Core Value in GIC data file	Kfactor
Three Phase, shell form	-1	0.33
Single Phase (Three separate cores)	1	1.18
Three Phase, 3-legged, core form	3	0.29
Three Phase, 5-legged, core form	5	0.66
Three Phase, 7-legged, core form	7	0.66
Kfactor determined base on base kV of transformer windings.		
Windings Highest Voltage	Kfactor	
Unknown core, <= 200 kV	0.6	
Unknown core, > 200 kV and <= 400 kV	0.6	
Unknown core, > 400 kV	1.1	

Using Transformer Capability Characteristics

A different approach for calculating transformer reactive power consumption due to GICs flow is described in [9].

12.7. References

[1] "Effects of Geomagnetic Disturbances on the Bulk Power System", NERC, 2012 Special Reliability Assessment Interim Report

[2] Application Guide - Computing Geomagnetically-Induced Current in the Bulk-Power System, North American Electric Reliability Corporation (NERC), December 2013

[3] D. H. Boteler and R. J. Pirjola, "Modeling Geomagnetically Induced Currents produced by Realistic and Uniform Electric Fields", IEEE Transactions on Power Delivery, Vol. 13, No. 4, October 1998, pages 1303-1308.

[4] D.H. Boteler and R. J. Pirjola, "The complex image method for calculating the magnetic and electric fields produced at the surface of the earth by the auroral electrojet," Geophys. J. Int., 132, 31-40, 1998.

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[8] X. Dong, Y. Liu, J. G. Kappenman, "Comparative Analysis of Exciting Current Harmonics and Reactive Power Consumption from GIC Saturated Transformers", Proceedings IEEE, 2001, pages 318-322.

[9] R.A. Walling and A.H. Khan, "Characteristics of Transformer Exciting-Current during Geomagnetic Disturbances", IEEE Transactions on Power Delivery, Vol. 6, No. 4, October 1991, pages 1707-1714.