TRANSMISSION PLANNING USING A QUANTITATIVE RELIABILITY CRITERION

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ABSTRACT

The application of probability techniques in power system reliability evaluation provides a quantitative measure of generation and transmission adequacy. The assessment of capacity benefits to systems involved in an interconnected pool for various types of interconnection agreement is illustrated in this thesis by a hypothetical example. The utilization of confidence levels on the forced outage parameters is illustrated by actual system data. The application of the conditional probability approach to the evaluation of individual load point reliability levels in practical networks is investigated using digital load flow techniques. This approach includes the outage states of both generation and transmission facilities and defines a bus failure in terms of a quality of service criterion.

A quantitative reliability criterion is proposed as a more consistent approach to transmission planning. A digital computer program has been developed which combines the reliability evaluation technique, the planning logic and the costing procedure. This program has been applied to a practical network configuration. The technique provides a valuable tool in assessing the costs of different reliability levels associated with alternate planning proposals.

TABLE OF CONTENTS

	Page
Copyright	ii
Acknowledgements	iii
Abstract	iv
Table of Contents	v
List of Figures	vii
List of Tables	ix
List of Symbols and Abbreviations	x
1. INTRODUCTION	1
2. GENERATING CAPACITY RELIABILITY EVALUATION	4
2.1 The Loss of Load Approach for Risk Evaluation in Single Systems	4
2.2 Load Forecast Uncertainty	6
2.3 Interconnected Systems	7
2.4 Outage Rate Confidence Levels of Generating Units	15
2.5 Frequency and Duration Methods	17
3. COMPOSITE SYSTEM RELIABILITY EVALUATION	24
3.1 Transmission System Reliability	24
3.2 Composite System Reliability Concept	26
3.3 Conditional Probability Approach	27
3.4 Computer Program	30
3.5 The Required Data	34
3.6 Study of a Simple Hypothetical System	36
3.7 Application to a Practical System	43
3.8 Subtransmission System Reliability	47
4. TRANSMISSION PLANNING	51
4.1 Transmission Planning Methods	51
4.1.1 General	51
4.1.2 Fencing technique	52
4.1.3 Linear programming techniques	53
4.1.4 The d.c. power flow method	54
4.1.5 A.C. load flow analysis	54
4.1.6 Method selected	55
4.2 Criteria for Transmission System Adequacy	56
4.2.1 Adequacy under normal operating conditions	56
4.2.2 Adequacy under emergency conditions	56

Page

4.3 Economic Generation Schedule 61
4.3.1 General 61
4.3.2 Methods of determining penalty factors 62
4.3.3 Economic dispatch using penalty factors as functions of the voltage phase angles 65

4.4 Required Data for Transmission Planning 72
4.4.1 General 72
4.4.2 Data preparation for the computer program 73

4.5 Transmission Planning Logic 75
4.5.1 The complete program 75
4.5.2 Low voltage logic 79
4.5.3 Overload logic 85
4.5.4 Reliability criterion 87
4.5.5 Single contingency outage criterion 87

4.6 Costing 89
4.6.1 The criterion of economic choice 89
4.6.2 Cost data 91

5. RESULTS OF PLANNING STUDIES 93

5.1 The Southern Saskatchewan System 93
5.2 The Major Network of the Saskatchewan System 110

6. CONCLUSIONS 117

7. REFERENCES 121

8. APPENDICES 126

8.1 Risk Level in System A of Figure 2.1 126
8.2 Minimum Duration of Exponentially Distributed Times 130
8.3 The Data for the Reliability Evaluation of the System Shown in Figure 3.2 130
8.4 The Data of the Southern Saskatchewan System 131
8.5 The Data for Transmission Planning Study of the Saskatchewan System 136

LIST OF FIGURES

Figure		Page
2.1	Interconnected Systems A,B and C	9
2.2	The daily peak load variation curve used for computing risk levels	10
2.3	Loss of load expectation using outage rates of generating units at different confidence levels	18
2.4	Increase in static reserve with increase in confidence level	19
3.1	The load probability distribution at a bus	31
3.2	A simple hypothetical system	38
3.3	The effect of acceptable minimum bus voltage on risk levels	42
3.4	The major transmission network of the Saskatchewan System	44
3.5	A simple subtransmission network	48
4.1	Flow diagram of the economic dispatch subprogram	66
4.2	A 3-plant system	69
4.3	Flow diagram of the transmission planning program	77
4.4	The low voltage logic	81
4.5	Different possible loopings	82
4.6	Tapping from a high voltage line through a transformer to LV bus	82
4.7	Conversion of an M/H line to high voltage	83
4.8	Building a line from a high voltage terminal priority bus to the low voltage bus	84
4.9	The overload logic	86
4.10	Conversion of an M/H line to high voltage for alleviating line overload	88

Figure		Page
5.1	The Southern Saskatchewan System	94
5.2	Transmission expansion of the Southern Saskatchewan System for various criteria	107
8.1	Loss of load in days for loss of load in megawatts	129

LIST OF TABLES

Table		Page
2.1	Interconnection Benefits to System A in Figure 2.1	11
2.2	Southern Manitoba System Hydraulic Generating Facilities	16
2.3	Frequency and Duration of States in a Two Unit System	22
3.1	Annual Failure Rates of Lines of Different Voltage Classes	37
3.2	Bus Risk Levels in the System Shown in Figure 3.2	40
3.3	S.P.C. Major Transmission Network Reliability	45
3.4	Risk Levels in the Subtransmission Network Shown in Figure 3.5	49
4.1	The Data of the 3-Plant System Shown in Figure 4.2	69
4.2	The Transmission Loss Formula Coefficients for the 3-Plant System Shown in Figure 4.2	70
4.3	The Plant Penalty Factors of the System Shown in Figure 4.2	70
4.4	Generating Plant Incremental Cost Data Assumed for the Saskatchewan System	71
4.5	The Plant Penalty Factors for the Saskatchewan System	71
5.1	The Transmission Planning in the Southern Saskatchewan System	96
5.2	The Present Worth of Transmission Requirements in the Southern Saskatchewan System for Various Criteria	109
5.3	The Transmission Planning in the Saskatchewan System	112

LIST OF SYMBOLS AND ABBREVIATIONS

λ_i	Failure rate of component i
μ_i	Repair rate of component i
B_j	An outage state
$P(B_j)$	Steady state probability of B_j
$R(B_j)$	Rate of departure from B_j
t	Duration of B_j
T	Cycle time of B_j
$F(B_j)$	Frequency of B_j
PG_j	Probability of generating capacity inadequacy for State B_j
PL_j	Probability of load at a bus exceeding the maximum load that can be supplied at that bus without failure, for State B_j
F_n	Input to plant n in dollars per hour
P_n	Output of plant n in MW
λ	Incremental cost of received power
P_L	Total transmission losses
L_n	Penalty factor of plant n
B_{mn}	Transmission loss formula coefficients
K_{jn}	X/R ratio of the transfer impedance between plants j and n
θ_{jn}	Difference between the voltage phase angles at plants j and n
F_{nn}	Slope of the incremental cost curve of plant n, approximated to a straight line
f_n	Intercept of the incremental cost curve of plant n
HV	High voltage
EHV	Extra High voltage
MV	Medium voltage
LV Bus	Bus with voltage less than the minimum acceptable value

M/H Line	Line designed for high voltage but operating at medium voltage
OL	Overloaded component
TP Bus	Terminal priority bus

INTRODUCTION

The investigation of alternate proposals and the evaluation of their associated costs is a preliminary requirement in any engineering planning study. The annual charges on power system transmission facilities amount to 25-30% of the total charges. The actual configuration and the associated costs of the transmission network are considerably influenced by the location of the future generating capacity which can have many alternatives. The application of a digital computer for automated transmission planning allows the planning engineer to investigate these alternatives with much less effort than by manual means. Computer utilization enables the creative engineer with the necessary system background to devote his talents to the development of the required basic logic. The labour of executing the logic can then be delegated to the computer. The ultimate selection of the desirable generation expansion pattern should include the transmission system as an integral part in the determination of the total costs.

A basic problem in the planning of either generation or transmission facilities is the determination of system adequacy under the forced outage of various system components. Rule of thumb measures do not provide a consistent assessment of reliability. Quantitative power system reliability evaluation[1] utilizes probability techniques to evaluate system reliability. This approach is gradually replacing the rule of thumb methods in the planning of system facilities. These techniques provide a consistent measure of adequacy and enable the planning engineer to determine the cost of reliability levels associated with alternate planning proposals. A quantitative reliability approach allows management to make decisions on a more consistent analytical basis than has previously been available.

Preliminary planning of generating capacity requirements is normally based on the simplifying assumption of complete transmission network reliability. The probability of loss of system load for a given total capacity is the basic measure of reliability in all the existing methods[2,3].

Existing transmission planning techniques test the transmission adequacy by considering the effect on the system of selected critically loaded component outages. A consistent measure of transmission adequacy, as in generation planning, can be obtained by probability techniques. Approximate formulas to determine the reliability of simple series-parallel configurations have been developed[6-9]. These techniques have been extended to include the theoretically more accurate Markov approach to transmission reliability evaluation[1,10]. Both transmission and generation facilities have been included in reliability evaluation using combinations of the above methods[11,12]. A conditional probability approach to composite system reliability has been proposed[1,13] and this technique has been extended in this thesis. In this approach, failure at a load point is defined in terms of quality of service rather than continuity of supply. A general design criterion has been postulated[13] as follows:

" (a) If with all transmission and generation facilities in service, station voltages are outside the defined limits then new facilities are required to meet the quality of service standards.

(b) If with the various possible combinations of system components out of service, the reliability index for the station is below an acceptable minimum, then additional facilities are required to meet the reliability standards."

This thesis includes a brief review of generating capacity reliability evaluation which was investigated in considerable detail in the author's M.Sc. thesis[2]. An appreciation of these concepts is necessary in the development of a composite approach to load point reliability assessment. The method of assessing capacity benefits to systems involved in an interconnected pool is also illustrated by a hypothetical system study for various types of interconnection agreements. The use of confidence levels in the determination of generating unit forced outage parameters is illustrated by utilizing the forced outage data for the Combined Southern Manitoba System generation facilities. This approach provides an additional degree of consistency to the reliability evaluation particularly when a limited amount of system data is available. The application of the conditional probability approach to obtain reliability indices at each load point in a practical networked configuration is investigated using digital load flow solutions. The bus reliability indices are utilized as quantitative measures of transmission system adequacy. A digital computer program has been developed combining the reliability evaluation technique, the planning logic and the costing procedure. The application is illustrated by a study of the simplified southern portion of the Saskatchewan System with and without the reliability criterion and for different generation expansion patterns. A study of the major transmission network of the Saskatchewan Power Corporation has also been included to illustrate the application of this approach to a relatively large practical network.

2. GENERATING CAPACITY RELIABILITY EVALUATION

2.1 The Loss of Load Approach for Risk Evaluation in Single Systems

The utilization of probability methods provides an analytical approach to the evaluation of power system generating capacity reliability. The size and type of the generating units, the system load characteristics and the emergency assistance available through interconnections can be readily incorporated in the analysis. The risk of inadequate generating capacity is obtained by combining the system capacity and load models.

There are four methods available at the present time to obtain a measure of the system generating capacity reliability. These are the loss of load probability method[16,17], the loss of energy probability method[16,17], the interval and duration method[18] and the simulation method[19]. A comprehensive survey[20] of the published literature indicated the loss of load probability approach to be the most widely accepted method and used more often than any other approach. This technique is extremely flexible and relatively simple to apply.

In the loss of load probability method, a table listing the probabilities of having various quantities of capacity forced out of service is obtained using existing and proposed generating unit data. This table is then combined with the system load characteristics to obtain an expected loss of load value in time units or a simple probability of loss of load. The risk expectation can either be in hours or in days for the period considered depending on whether the hourly integrated load duration curve or the daily peak load variation curve is used.

In a practical system containing a large number of units of different capacities, the capacity outage probability table will contain several hundred possible discrete capacity levels. This number can be reduced by grouping the units into identical groups prior to combining or by rounding the table to discrete levels after combining. Unit grouping prior to building the table introduces unnecessary approximations which can be avoided by the table rounding approach. The capacity rounding increment used depends upon the accuracy desired. The final rounded table contains capacity outage magnitudes that are multiples of the rounding increment. The number of capacity levels decreases as the rounding increment increases, with a corresponding decrease in accuracy.

Generating unit maintenance has been incorporated by some authors in these studies by adding the capacity on maintenance to the load or subtracting it from the installed capacity without altering the outage probabilities[3]. This procedure usually results in higher calculated risk levels and the error increases with increased maintenance capacity. This error may be negligible in a large system in which the capacity on maintenance is an extremely small percentage of the total installed capacity. Removing units on maintenance from the capacity outage probability table by the method developed in Reference 2, gives the same table as obtained by combining only the units available when the units being removed are exact multiples of the rounding increment used in the table. The resulting error in other cases, is negligible for normal magnitudes of capacity on maintenance. In order to consider maintenance it is necessary to divide the year into intervals during which the generating capacity is constant. The adequacy of the generating capacity during each of the maintenance intervals is determined by converting the risk in the interval to a common time base and comparing it with the acceptable risk level. This technique is necessary to avoid the tendency to assume that for a particular interval, a low loss of load expectation value indicates little risk. The low value may be due to the interval itself being very small and not due to a high reserve capacity margin.

If the year can be divided into a peak load season and a light load season, the planned maintenance may be scheduled entirely in this latter period. The contribution of the light load season considering maintenance to the annual risk is normally quite low. The annual risk evaluation may be simplified by using the annual forecast peak and the system load characteristic and capacity model neglecting maintenance. In some cases, the load level in a particular season or even a month may be so high that this risk value dominates the annual figure. A reliability criterion for such a system can be obtained using only this "worst period" value[3]. This approach, however, should not be used to compare the risk levels in two different systems with different annual load characteristics. This approach is only consistent when applied continually to the same system.

2.2 Load Forecast Uncertainty

In practice the load forecast is based on past experience and therefore it is extremely unlikely that the actual load will be exactly equal to the forecast value. If it is realized that some uncertainty can exist, it may be described by a probability distribution whose parameters are determined from past experience. The uncertainty in load forecasting can be included in the risk computations[2] by dividing the load forecast probability distribution into class intervals, the number of which depends upon the accuracy desired. The area of each class interval represents the probability of the load being the class interval mid-value. The loss of load expectation is computed for each load represented by the class-interval and multiplied by the probability of that load existing. The sum of these products represents the loss of load expectation for the forecast uncertain load. The normal distribution has been assumed by some authors to describe the load forecast uncertainty. The uncertainty results in a higher risk level which increases rapidly as the uncertainty increases. Appreciation of uncertainty is essential when evaluating the risk levels associated with future installed capacity requirements. Sufficient historical data must be collected to describe the exact distribution of load forecast uncertainty.

2.3 Interconnected Systems

The use of interconnections between power systems can be an extremely effective means of improving the level of reliability in each individual system. The diversity existing between the two areas, in system load and in the forced outage of generating equipment will allow each area to operate on less reserve than would normally be required for isolated operation. The installed capacity benefits due to interconnection depend mainly on the operating reserve in the individual systems, the interconnection limitations and the type of agreement between the two systems regarding emergency assistance. The loss of load probability method can be readily applied to risk evaluation in two interconnected systems[15,21]. The first step in this approach is to develop a combined system capacity outage probability table from the individual system tables. This combined table is in the form of a two dimensional array of the various simultaneous outage probabilities in the two systems. The loss of load in each system for each of the simultaneous outage conditions is computed considering the emergency assistance from the other systems and combined with the load characteristic to obtain the risk contribution. The sum of the risk contributions from all the simultaneous outage conditions is the system risk. The emergency assistance depends on the type of agreement and may be limited to the operating reserve or to a maximum specified amount. In the one company concept of operation, each system may assist the other even to the extent of losing some of its own load if necessary. In some cases, capacity from one system may be committed for firm sale to the other with remaining tie capacity providing further emergency assistance. In any type of agreement the maximum assistance is limited by the tie capacity. The uncertainty can be incorporated as indicated in Section 2.2. Using this approach a previous study of the Saskatchewan and Manitoba Systems[15] in which the emergency assistance is limited by the operating reserve, indicated that as the interconnection capacity increases upto a certain point, the individual system risk levels decrease considerably. An "infinite tie capacity" was defined for two interconnected systems as that capacity beyond which any further increase does not increase the level of reliability of the systems. The tie line forced outage rate was considered by modifying the emergency assistance by the availability probability. It was found that normal values of tie line forced outage rate do not materially affect the results.

An extension of the method of evaluating risk levels in two interconnected systems to find the risk levels when a third system is also connected has been suggested by R.Billinton[56]. An assistance probability table of the third system is obtained which contains the different capacity assistance levels each with a probability of availability. The table is developed using the capacity outage probability table, available system reserve and the tie capacity. For a given capacity on outage, the assistance is equal to the difference between the operating reserve and the capacity on outage or the tie capacity whichever is less. The probability of this assistance is the probability of the capacity outage itself. If System A is connected to Systems B and C as shown in Figure 2.1, the risk level in System A is obtained using the combined capacity model of Systems A and B, adding the capacity assistance from System C to System A directly, and multiplying the expected load loss by the probability of the assistance from System C. The sum of the products obtained for all the levels in the assistance probability table of System C is the risk in System A. This method is utilized in the following study of interconnection benefits.

The interconnection benefit to a system can be defined as the increase due to the interconnection in the system load carrying capability at a specified risk level. The load carrying capability can be obtained from a study of the variation in risk with peak load for the system. The concept of interconnection benefit is illustrated by the study of the hypothetical system shown in Figure 2.1.

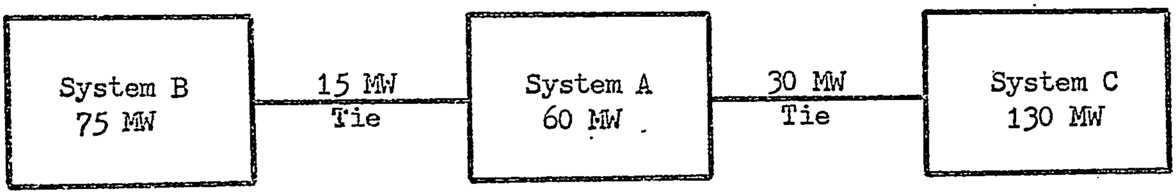


Figure 2.1 Interconnected Systems A, B and C

The generation and load data are as follows:

System	Number of Units	Unit Capacity	Total Capacity, MW	Peak Load, MW
A	4 1	10 20	60	40
B	5 1	10 25	75	50
C	5 1	20 30	130	90

A forced outage rate of 0.02 per unit was assumed. The load model used in each system is shown in Figure 2.2. A 15 MW tie between Systems A and B and a 30 MW tie between Systems A and C with zero probability of unavailability were assumed.

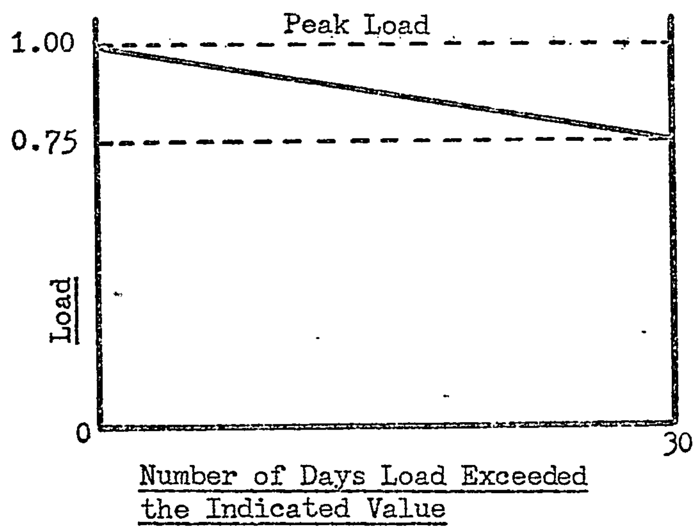


Figure 2.2 The Daily Peak Load Variation Curve
Used for Computing Risk Levels

System A was studied to determine the benefits due to interconnection with System B and with System C separately and with Systems B and C together. An interconnection providing a firm capacity purchase was also studied. These results are shown in Table 2.1 (a). The results for

TABLE 2.1

Interconnection Benefits to System A in Figure 2.1

(a) Different Cases

(Load carrying capability of System A at risk level of loss of load expectation 0.001 days/month = 24.32 MW)

Case Number	Interconnection details	Benefit, MW
1	Connected to System B with tie capacity: 15 MW	12.35
2	Connected to System C with tie capacity: 30 MW	17.32
3	Sum of the benefits obtained from B and C separately	29.67
4	Connected to Systems B and C simultaneously	31.92
5	Firm purchase of 10 MW	12.15
6	Firm purchase of 10 MW with 15 MW tie to System B	17.02
7	Firm purchase of 10 MW tied to 25 MW unit in System B	9.20
8	Same as Case 7, but with additional benefit due to remaining tie capacity of 5 MW	12.51

TABLE 2.1(b)

From System B with Different Loads

Peak Load in B	Reserve in B	Benefit to A at Risk Levels 0.1: 15 MW Tie	0.1: 30 MW Tie	0.01: 15 MW Tie	0.01: 30 MW Tie	0.001: 15 MW Tie	0.001: 30 MW Tie	0.0001: 15 MW Tie	0.0001: 30 MW Tie
75	0	0	0	0	0	0	0	0	0
70	5	4.58	4.58	4.74	4.74	5.38	5.38	2.63	2.63
65	10	8.68	8.68	8.85	8.85	6.66	6.66	2.96	2.96
60	15	12.96	12.96	11.90	11.90	10.95	10.95	7.94	7.94
55	20	14.04	16.72	12.96	13.39	11.68	12.96	10.03	10.08
50	25	14.81	*	13.96	15.52	12.35	14.50	10.16	10.26
45	30	15.18	*	15.26	20.37	14.52	17.77	14.13	14.67
40	35	15.37	*	15.44	24.48	16.27	20.44	14.49	17.55

* Load carrying capability in System A is greater than 60 MW

TABLE 2.1(c)

From System C with Different Loads

Peak Load in C	Reserve in C	Benefit to A at Risk Levels 0.1 15 MW Tie	0.1 30 MW Tie	0.01 15 MW Tie	0.01 30 MW Tie	0.001 15 MW Tie	0.001 30 MW Tie	0.0001 15 MW Tie	0.0001 30 MW Tie
130	0	0	0	0	0	0	0	0	0
125	5	4.58	4.58	4.74	4.74	5.38	5.38	2.63	2.63
120	10	8.68	8.68	8.85	8.85	6.66	6.66	2.96	2.96
115	15	9.87	9.87	9.10	9.10	6.91	6.91	3.36	3.36
110	20	9.87	10.48	9.10	9.19	6.91	6.93	3.36	3.36
105	25	12.95	14.90	11.90	12.50	10.96	11.05	7.94	8.49
100	30	13.96	*	12.96	13.76	11.68	12.94	10.03	10.10
95	35	15.10	*	14.71	18.23	13.85	16.21	11.37	11.80
90	40	15.24	*	15.07	21.00	15.70	17.32	11.82	12.29
85	45	15.40	*	15.39	25.37	16.09	21.10	14.72	16.00
80	50	15.43	*	15.51	*	16.45	23.00	14.76	19.50

* Load carrying capability in System A is greater than 60 MW

Cases 1, 2, and 3 were obtained by the method developed for two interconnected systems. The results for Case 4 were obtained by developing a capacity model for Systems A and B and using the assistance probability table of System C, as shown in detail in Appendix 8.1. In Case 5, the firm purchase of 10 MW was added to the capacity in System A as a 10 MW unit of zero forced outage rate in obtaining the risk level. In Case 6, the firm purchase of 10 MW from System B was added to the capacity in System A and subtracted from that of System B. It was assumed that additional assistance between the systems is possible over the remaining tie capability of 15 - 10 = 5 MW. The risk level in System A was obtained using the two interconnected systems approach with a 5 MW tie capacity. In Cases 5 and 6, the firm purchase is backed by the complete system selling the power with no conditions attached. In Case 7 the sale is tied to the 25 MW unit in System B. If the unit is out of service the sale capacity is not available. The risk in System A is the sum of the expected risk contributions with and without the 10 MW addition. The expected risk values are obtained by multiplying the calculated risk by either the probability of availability or the forced outage of the unit to which the sale is tied. In Case 8 the sale is tied to the 25 MW unit as in Case 7. Emergency assistance over the remaining tie capability of 15 - 10 = 5 MW was also considered. The risk level in System A was obtained in two steps. First by adding 10 MW to the capacity of System A and by subtracting 10 MW from the capacity in System B with a 5 MW tie capacity. The System B capacity outage probability table was developed adding the 25 MW unit with zero forced outage rate. The risk level in System A was multiplied by the availability probability of the 25 MW unit (1.00 - 0.02 = 0.98). In the second step, the System A capacity was not modified, the 25 MW unit was not included in the System B capacity model and 15 MW tie capacity was used. The risk in System A was multiplied by the probability of the 25 MW unit being unavailable. The sum of the products in the two steps is the System A risk and this value was used to compute the benefit in Case 8.

Interconnection benefit to System A from Systems B and C separately were computed for tie capacities of 15 and 30 MW and are shown in Tables 2.1(b) and (c). Due to the larger size units in System C, the benefits are less than those from System B, even though System C has a higher operating reserve. The techniques illustrated in this simple system example have also been used to determine the benefits to the Manitoba System from the Saskatchewan and Ontario Interconnections[56].

2.4 Outage Rate Confidence Levels of Generating Units

The use of confidence levels in the determination of a capacity outage probability table is a means of adding an additional degree of consistency to the analysis. Many utilities are now commencing to collect outage data for units which have progressed well into their useful life period. Based on the limited data available, confidence bounds can be placed upon the forced outage rate. As additional outage data becomes available, the outage statistics can be modified while retaining a fixed degree of confidence. The confidence level therefore becomes an integral part of the reliability criterion which when evaluated for the present system can be utilized in future system analysis.

The basic statistics in the determination of a capacity outage probability table are the individual generating unit average forced outage rates[22]. These values are generally estimated for the units concerned from an analysis of the unit histories. The averages are, therefore, single point estimates of the probabilities of finding the various units on outage in the future. A recent publication[23] discussed the question of the degree of confidence that can be placed in the expected loss of load due to the uncertainty in the generation and the load model statistics. Various capacity outage probability models were created by randomly selecting the unit forced outage rates using the distribution dictated by their individual histories. The basic theory of placing confidence bounds on the forced outage rate was first introduced in a 1959 publication[24]. The basic assumptions in this approach are that the individual unit up-period durations and down-period durations are exponentially distributed.

Consistent generating unit forced outage data has been collected in the Manitoba System since early 1960 using a comprehensive reporting procedure prepared by the Canadian Electrical Association. The hydraulic generating units located in the Southern Manitoba System are listed in Table 2.2.

TABLE 2.2

Southern Manitoba System Hydraulic Generating Facilities

No. of units	Capacity per unit MW	Total Capacity MW
5	3.2	16.0
3	4.0	12.0
8	5.5	44.0
8	7.0	56.0
8	8.5	68.0
6	13.5	81.0
6	22.0	132.0
6	25.0	150.0
	Total:	559.0

The forced outage rates of each individual unit were computed[25] at selected upper bound confidence levels using the available individual unit histories and the equations developed in Reference 24. The capacity outage probability table at each confidence level was then combined with the annual load duration curve to give the annual expected loss of load in hours. The results are shown in Figure 2.3. The 50% confidence level value corresponds generally to the conventional cumulative forced outage rate and the best point estimate. The increase in reserve required to maintain a constant risk while demanding an increase in confidence level is shown for selected risk levels in Figure 2.4.

In a generating capacity planning study the forced outage rates of existing units are determined at a selected confidence level from the available data rather than using data of other systems whose maintenance policies or operating conditions may be different. In the case of future units for which there are no similar units existing in the system, it is necessary to use the experience of other systems. The selection of the confidence level as in the case of the acceptable degree of reliability for the system is a management decision.

2.5 Frequency and Duration Methods

In power system reliability studies, the probability of an unsatisfactory condition is the most commonly used measure of risk. The average frequency and average duration of the failure mode provide a more meaningful measure and may be more useful in certain cases. These measures, however, are sometimes not as flexible as the simple probability measure in regard to the inclusion of all the desired variables in the analysis. Simplifying assumptions may be necessary in some cases to obtain an approximate measure of frequency or duration rather than the exact frequency

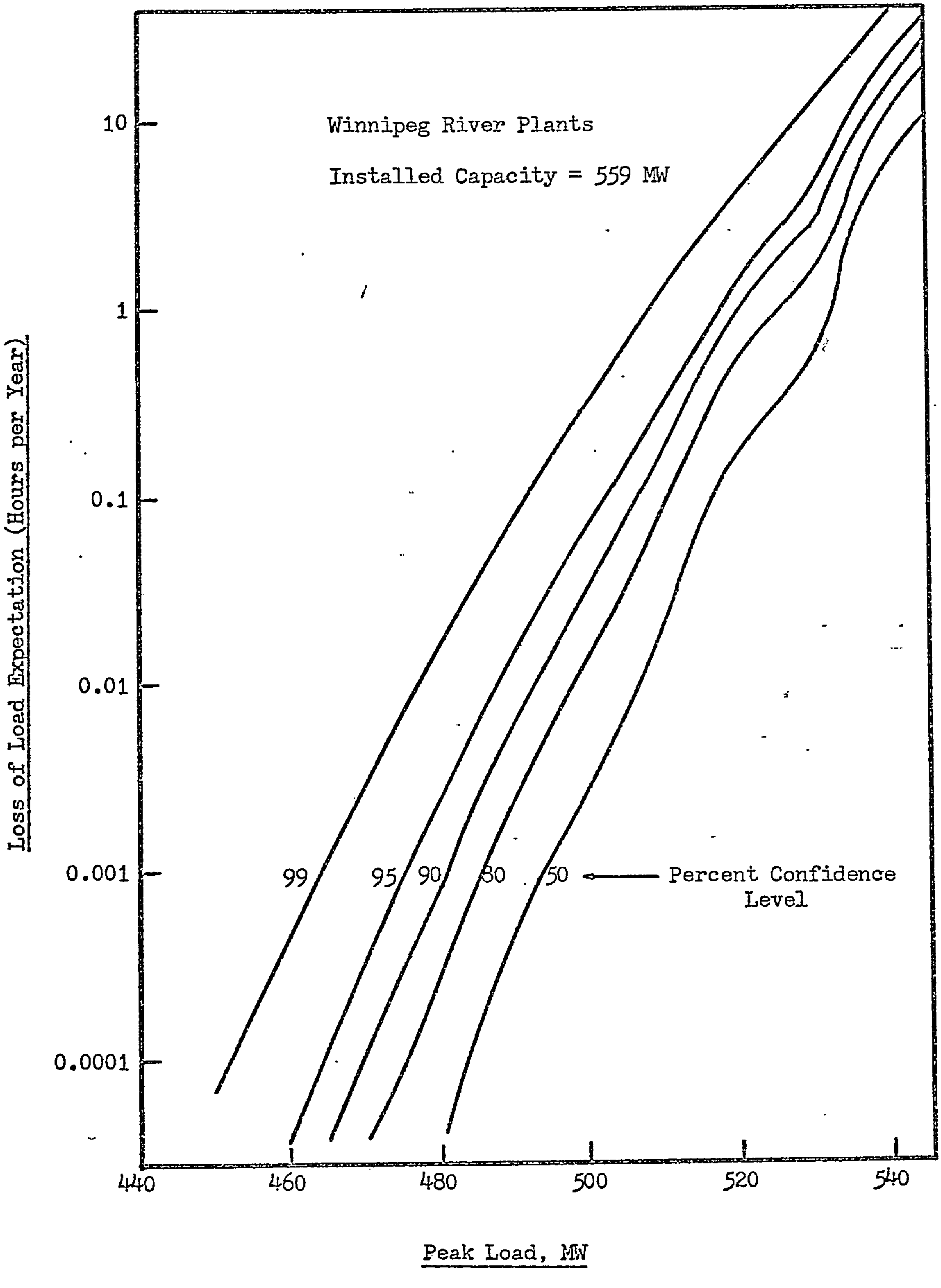


Figure 2.3 Loss of Load Expectation Using Outage Rates of Generating Units at Different Confidence Levels

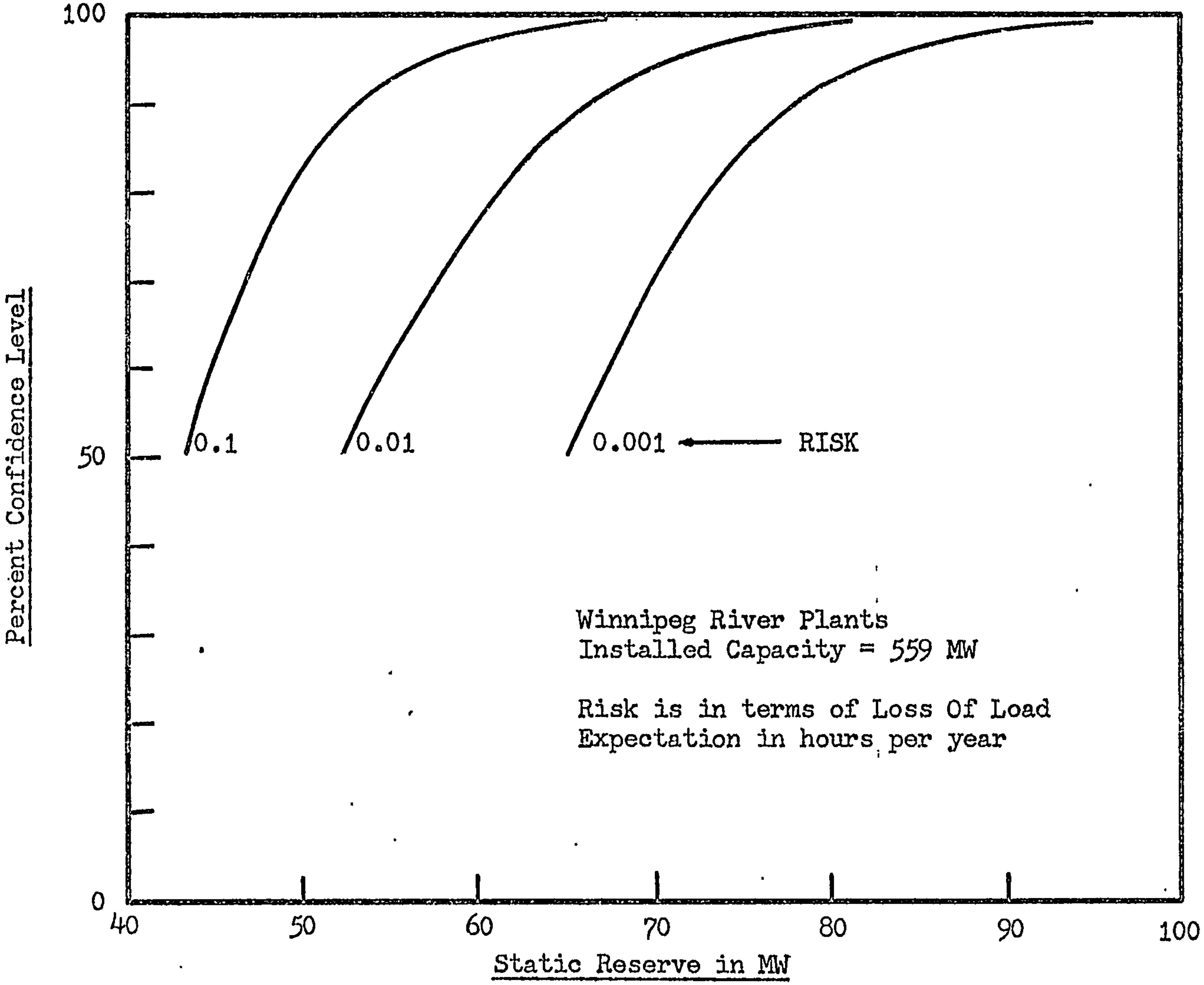


Figure 2.4 Increase in Static Reserve with Increase in Confidence Level

or duration itself.

A 1958 publication[18] reported the first application of frequency and duration techniques to generating capacity reserve studies of practical systems. Two recent papers[26,27] used a Markov approach and developed a simple method of combining generating units with their failure and repair rates. This capacity model was then combined with the system load model to obtain the frequency of capacity margin states. The associated theory is required later in this thesis and it is therefore briefly reviewed in this section. The theory is applicable to any group of units operating in parallel or to determine the frequency and duration of various states in which a set of generating units, transmission lines and transformers can exist with some of them in service and the remaining under forced outage.

In the following analysis it is assumed that each unit can exist only in two states, either available or under forced outage and that the unit outages are independent random events. Each unit, i is represented by a failure rate, λ_i and a repair rate, μ_i. The failure times and repair times are assumed to be independent of each other and are exponentially distributed with $1/\lambda_i$ and $1/\mu_i$ respectively as the average times. The steady state probability of availability of unit i is $\mu_i/(\lambda_i + \mu_i)$, and the steady state probability of unavailability due to forced outage is $\lambda_i/(\lambda_i + \mu_i)$.

Consider a total number of n units and a particular state B_j in which m units are under forced outage and the remaining (n - m) units are operating. The steady state probability of existence of the state is given by:

$$P(B_j) = \prod_{i=1}^{m} \left[\lambda_i/(\lambda_i + \mu_i) \right] \prod_{k=1}^{n-m} \left[\mu_k/(\lambda_k + \mu_k) \right] \qquad 2.1$$

The rate of departure from the state is defined as,

$$R(B_j) = \sum_{i=1}^{m} \mu_k + \sum_{k=1}^{n-m} \lambda_k \qquad 2.2$$

A transfer from state B_j will occur if another repair or failure occurs. The duration of this state is given by the minimum value of the corresponding failure and repair times. It is shown in Appendix 8.2 that the distribution of the minimum time is exponentially distributed with an average value equal to the reciprocal of the rate of departure from the state. The duration (t) of the state is therefore given by:

$$t = 1/R(B_j) \qquad 2.3$$

If the cycle time, T is defined as the average occurrence time of the state, the probability of existence of the state is equal to the duration divided by cycle time of the state.

$$P(B_j) = t/T \qquad 2.4$$

$$T = t/P(B_j) = 1/\left[P(B_j) \; . \; R(B_j)\right]$$

If the frequency of encountering the state, $F(B_j)$ is defined as the reciprocal of the cycle time T,

$$F(B_j) = P(B_j) \; . \; R(B_j) \qquad 2.5$$

The frequency of encountering a state is equal to the product of the steady state probability of existence of the state and the rate of departure from that state. Applying this rule it is possible to determine the frequencies of various states in the system. This is illustrated by a two unit example in Table 2.3.

TABLE 2.3

Frequency and Duration of States in a Two Unit System

	Failure Rate	Repair Rate
Unit 1	λ_1	μ_1
Unit 2	λ_2	μ_2

State	Unit 1	Unit 2	Rate of Departure = 1/Duration	Probability	Frequency = 1/Cycle Time
1	Up	Up	$\lambda_1 + \lambda_2$	$\mu_1\mu_2/D$	$\mu_1\mu_2(\lambda_1 + \lambda_2)/D$
2	Down	Up	$\mu_1 + \lambda_2$	$\lambda_1\mu_2/D$	$\lambda_1\mu_2(\mu_1 + \lambda_2)/D$
3	Up	Down	$\lambda_1 + \mu_2$	$\mu_1\lambda_2/D$	$\mu_1\lambda_2(\lambda_1 + \mu_2)/D$
4	Down	Down	$\mu_1 + \mu_2$	$\lambda_1\lambda_2/D$	$\lambda_1\lambda_2(\mu_1 + \mu_2)/D$

Note: $D = (\lambda_1 + \mu_1)(\lambda_2 + \mu_2)$

The application of the loss of load approach is more widely accepted in generating capacity reliability evaluation than any other method. The approach can also be used to evaluate interconnection benefits when more than two systems are involved in the pool. The frequency and duration approach has been gaining considerable importance recently. The measure of frequency and duration is more meaningful than a simple probability value, however, the approach is not as flexible as the loss of load probability approach. When limited outage data are available outage rates can be obtained at a selected confidence level. The selection of the confidence level is a management decision as is the case of an acceptable reliability criterion.

3. COMPOSITE SYSTEM RELIABILITY EVALUATION

3.1 Transmission System Reliability

The published literature indicates that the application of probability methods in generating capacity planning is reasonably well-accepted. Application in the area of transmission system planning is, however, far from this stage at the present time. This is clearly indicated by the relatively small number of publications on this subject. Most of the earlier papers discussed reliability in a qualitative rather than quantitative sense. The first method for evaluating quantitative reliability appeared in an I.E.E.E. 1964 publication[6]. This method determines the probability of forced outage of a specified minimum duration to obtain the customer interruption rate and the number of interruptions exceeding a given duration. The approach is applicable to simple series-parallel combinations of system components. The method is based entirely on continuity of supply to the load points and assumes complete redundancy in parallel components.

A second method of transmission reliability evaluation was also published[7] in 1964. The application of this method and the computer program were reported in a 1965 publication[8]. This method again dealt with series and completely redundant parallel systems. Certain specific assumptions were made regarding the probability distribution of component repair and failure rates. The most important aspect of this approach was the introduction of a fluctuating environmental condition associated with the operating component and normal weather and stormy weather states were used to describe this environment. Additional accuracy may be gained by identifying different types of storms rather than including all storms in a single state. This would introduce considerable difficulty in data collection and in the reliability application. The failure rates associated with each weather condition can be obtained using a consistent and well defined reporting procedure. The method assumes that the component failure times, repair times, storm durations and normal weather durations are characterized by exponential probability distributions. Equations using certain approximations were developed to determine the average customer interruption rate and the average duration of the interruption. It is difficult to apply this method to complicated systems and it becomes more of an approximation as additional parallel facilities are combined.

The methods described were stated to be approximations which would give results within a few percent of those obtained using more theoretical techniques, such as Markov processes. The application of Markov chains was briefly noted in a 1964 I.E.E.E. publication[11]. It was stated that within the bounds of the distributional assumptions made, the Markov approach is theoretically the most accurate approach. The method was first applied to series-parallel components considering the two state fluctuating environment in a 1967 publication[10]. The theory of Markov processes dealing with systems that are discrete in space and continuous in time has been used in the method. The transitional probability matrix contains the probabilities of transition from any one state to any of the other various system component states. It is relatively simple to obtain the mean time to enter the failed state, if the only criterion of success is continuity of supply. The number of simultaneous equations to be solved in order to determine the limiting state probabilities is 2×2^n for n components in a two state fluctuating environment. This number increases rapidly as n increases. Results obtained by the Markov approach were compared to those obtained by the second method[7,8] for simple parallel configurations and it was concluded[1] that the second method responds quite differently to changes in system parameters and can be quite incorrect in certain cases.

3.2 Composite System Reliability Concept

Various methods have been presented and applied in the areas of generating capacity and transmission system reliability evaluation. The evaluation of composite system reliability is, however, still at the preliminary stage. The object is to provide a measure of reliability at any point in a composite system including both generation and transmission facilities. The basic problem in this regard is the definition of failure at any point in a system. If load point reliability is considered only in terms of continuity then success and failure is easily defined. A Boolean algebraic approach has been suggested to determine success or failure of a system with respect to a load point[11]. This approach, however, becomes extremely complicated when applied to a system with several supply points and networked components. In a recent publication[12] the frequency of supply failure to a station is given by the summation of the component outage rates weighted by the probability of overload on the remaining components. Simulation of hourly loads in a year and load flow analysis were used to provide information of the duration of the contingency conditions.

A method of composite system reliability evaluation was presented in a recent paper[13] using the conditional probability approach. This method proposed the use of a service quality standard as the reliability criterion rather than simple continuity between sources and load points. The definition of a breach of continuity was extended to include a breach of quality. If due to line outages the voltage level at a load point is lower than the desired minimum, this is a breach of quality and should be treated as a failure even though it is not an actual breach of continuity. This would not include voltage transients due to system disturbances. The effect of failure during storms, acceptable bus voltage levels, shunt capacitive compensation, and transmission redundancy were illustrated by applying the method to a simple system. The basic technique for analyzing a more complicated network was indicated.

3.3 Conditional Probability Apprcach

In a power system network, there are a finite number of possible outage combinations of lines, transformers and generating units. Each outage condition has a probability of existence and frequency of occurrence as shown in Section 2.5. Under each outage condition there is a maximum load that can be supplied at each bus without violating the service quality criterion. The probability that the load will exceed this maximum value can be determined from the load probability distribution for the bus in question. This is a conditional probability as the maximum load is determined given that the outage condition has occurred. In the previously noted paper[13], the system generating facilities were included by developing a capacity outage probability table for all the units within the system. The maximum load that can be supplied at a bus can be obtained for any given outage condition in the transmission system. This is shown in the next section. The probability of the load at the bus exceeding this value is then combined with the probability that the available system generating capacity is insufficient to meet the total system load. Generation and transmission outage conditions are considered as two independent events resulting in failure at a bus. This probability is weighted by the probability of the outage condition itself and the summation for all possible outage conditions gives the probability of failure at the bus. This is shown in Equation 3.1.

$$\text{Probability of failure at Bus k} = \sum_j P(B_j)\left[PG_j + PL_j - PG_j \cdot PL_j\right] \qquad 3.1$$

where

B_j = An outage condition in the transmission network (lines and transformers)

$P(B_j)$ = Probability of the existence of outage B_j

PG_j = Probability of the generating capacity outage exceeding the reserve capacity (a cumulative probability figure obtained from the capacity outage probability table)

PL_j = Probability of load at Bus k exceeding the maximum load that can be supplied at that bus without failure

The probability of existence of outage B_j is obtained by assuming that the individual component outages are independent. The two state fluctuating environment should be considered when outdoor transmission facilities are involved. It has been shown[13], however, that the effect of storm associated failures on the probability of system failure is virtually negligible in those cases in which there is a reasonable probability that the system load will exceed the remaining transmission capability. The effect of storms would be further diminished in major transmission reliability evaluation over relatively long distances as storms become more local in nature.

It is also possible to determine a reliability index at any bus in the system in terms of an average or expected frequency of failure. The frequency of occurrence of an outage condition is equal to the product of the probability of existence of the outage and the rate of departure from that condition as shown in Section 2.5. If the generating unit outages and the load variation are considered in terms of probability only and not in terms of frequency of occurrence, then the expected frequency of failure at Bus k is given by:

$$\sum_j F(B_j) \left[PG_j + PL_j - PG_j \cdot PL_j \right] \qquad 3.2$$

where

$F(B_j)$ = Frequency of occurrence of outage B_j

The frequencies associated with the individual generating units can be included in the evaluation with no additional assumptions. This is shown later in this section. The inclusion of the frequency of load model states for each bus becomes extremely complicated as shown in a recent publication[27].

In the approach described by Equation 3.1, the generation schedule used in the load flow analysis is not modified to include the outage of individual units. The assumption is made that any breach of quality is due to line or transformer outages or to the system load exceeding the total available generation. This assumption is not required if the individual generating units are considered together with the transmission lines and transformers to determine each outage condition B_j. The generation schedule is then modified for each outage condition involving a generating unit outage. The number of individual outage conditions in this case may be much greater than those considered using Equation 3.1, depending on the number of generating units. This approach is, however, more accurate as the bus voltage and line loadings are affected by the generation schedule. The equations for this case are as follows:

Probability of failure at Bus k $= \sum_j P(B_j) \cdot PL_j$ 3.3

Expected frequency of failure at Bus k $= \sum_j F(B_j) \cdot PL_j$ 3.4

where

B_j = An outage condition including generating units, lines and transformers

In Equation 3.4 as in Equation 3.2, the frequencies associated with the load model states are not included in the evaluation.

3.4 Computer Program

The most important step in applying Equations 3.1 to 3.4 is the determination of the maximum load that can be supplied at each load point in a practical system. In this regard, a load flow solution using a digital computer provides a fast and reasonably flexible approach. Several basic assumptions were used to simplify the computer program. The load variation at each bus was represented by a normalized load duration curve, approximated by a single straight line. The individual bus load levels used in each load flow analysis are those which correspond to probability values of exceedance specified in the input data.

A load bus is assumed to be failed under the following conditions.

i) The voltage at the bus is less than a specified minimum value, (not meeting the quality standards at the bus)

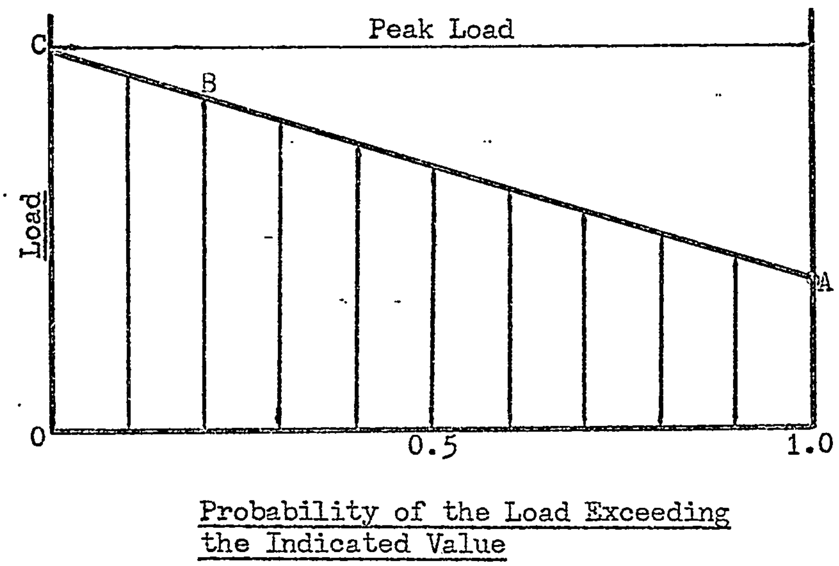
ii) A line or transformer supplying power to the bus is overloaded

iii) The generating capacity required to meet the total load exceeds the available capacity (this includes transmission losses)

The second assumption may define some buses in a system as failed even though their voltage level is acceptable, which results in a higher risk contribution at those buses than the actual value. This has an advantage in transmission planning as the transmission improvements made by the program required to alleviate the high risk will tend to reduce the overload.

The digital computer program was developed as a sub-program in the overall transmission planning program described in Chapter 4. This program creates the possible outage conditions and performs a load flow analysis for each outage condition and specified load level. If for an outage condition B_j, a load bus fails at any of the specified increasing load levels, PL in Equation 3.1 is taken as the average of the probability value of the load level at which the load bus has failed and of the previous lower level. PL is zero if the load bus does not fail even at the peak load level. This is illustrated in Figure 3.1. PG in Equation 3.1 is the cumulative probability of the capacity outage in the system exceeding the reserve. In the systems studied it was found that sufficient accuracy could be obtained by considering up to a maximum of two simultaneous independent outages and that there was a negligible risk contribution from outages of higher order.

Figure 3.1 The Load Probability Distribution at a Bus



Bus Failure Condition at Load Level	A	B	C
PL in Equations 3.1 to 3.4 . .	1.0	0.25	0.0

If due to some outage condition a load bus is isolated from the network, PL is equal to 1 for that bus. The scheduled generation at various buses in this case is reduced by the factor (Total load - Load at the isolated bus)/(Total load), to avoid any possible load flow convergence problems. If generation is lost due to the isolation of a generating bus, the generation schedule is increased (limited to the maximum available) by a factor (Total generation)/(Total generation - Generation lost). In this case, the capacity outage probability table for the system is modified by removing the generating units at the isolated bus before using the table for computing PG. Unit removal from the capacity outage probability table is accomplished using the method devised in Reference 2. If there is a load at the isolated generating bus, the contribution to the bus risk is computed by combining the load and the generating capacity models at the bus as in a normal loss of load probability study. If the isolated generating bus is the swing bus, another bus is selected for this purpose.

If for a given outage condition, the load flow solution does not converge within a specified maximum number of iterations the system is divided into sub-systems with each generating bus supplying one or more neighbouring loads. The risk contribution is then calculated for each bus using the capacity outage probability table at the generating bus and a combined load duration curve for the loads being supplied. Preliminary studies may be required to specify for each load, the possible paths to a generating bus which can maintain the desired voltage at the load bus. The program checks these paths for continuity and decides which generating bus must supply the load. The procedure may not be exact, but the error involved is relatively low as this situation generally occurs for outage conditions which have extremely low probabilities of existence.

If a line or transformer is overloaded at any load level it is assumed to be tripped by the protective equipment and therefore removed from the network. Some loads may be tripped off the system rather than allowing other load points to experience undesirable voltage levels. A specific division of the system into sub-systems may be preferred by experience if necessary for a given outage condition. These conditions together with any other operating policies can be readily incorporated in the reliability evaluation. This is an advantage of this approach over the method using previously obtained contingency curves[12].

The risk evaluation is performed only if the base case load flow solution with all the system components in service is satisfactory. The load flow solution is obtained by the conventional Gauss-Seidel method. The program developed is not a highly sophisticated one and no provision is made for automatic tap adjustment to correct low voltages. Each load flow solution is obtained with the generating bus voltages set to the maximum possible values, without exceeding the VAR limits. VAR adjustment is made by changing the generating bus voltage magnitude in steps of 0.01 per unit.

The system loads can be represented in the load flow program by either constant power or constant admittance models. The loads can also be represented by constant power models for voltage above a specified minimum and modified to a constant admittance representation if the voltage falls below the minimum. A constant admittance representation increases the diagonal dominance of the nodal admittance matrix and results in a significant saving in solution time. The admittance for this representation is computed from the constant power load specified in the data using the bus voltages obtained from the base case load flow solution.

Capacity outage probability tables are developed[28] separately for each generating bus and an additional table for the entire system. The tables can be rounded[2] to a desired rounding increment to reduce the size. Provision is made to add units to the table at any bus and to the system table in any year of a planning study.

Alleviation of low voltages and overloads by changes in the generation schedule before testing for bus failure conditions is not attempted in the program. This should be approached by trial and error and in a practical network with several generating sources it becomes complicated and increases the computation time considerably. It is possible that sometimes the changes cannot alleviate the low voltage and overload conditions or they may transfer these conditions to some other location in the network. It was felt that consistent reliability indices which may be somewhat pessimistic can be evaluated by assuming a fixed generating schedule and not attempting to alleviate bus failure conditions. This assumption is consistent with the transmission planning technique discussed in Chapter 4 where the transmission adequacy is tested under an economic generation schedule and no generation changes are made to alleviate any low bus voltage and line overload conditions.

3.5 The Required Data

The data required for a composite system reliability study includes all the data necessary for normal load flow analysis plus the additional data required for reliability evaluation. These requirements are listed as follows:

Line parameters:

Per unit impedance, susceptance and current rating.

Transformer parameters:

Per unit impedance, current rating and the tap.

Bus data:

Per unit active and reactive load represented as constant power; the normalized load duration curve approximated to a straight line; the number and capacity of generating units; generation schedule at different levels of the system load, the variation being approximated to a straight line; the static capacitance; the estimated voltages and voltage limits; and the reactive power generation limits.

Other data:

Acceleration factors, voltage tolerance and the maximum allowed number of iterations for convergence of the load flow solution; swing bus to be used normally and the bus to replace the swing bus when isolated; the base MVA; the bus voltage limit below which the load should be modified to a constant admittance representation; the increments for rounding the capacity outage probability tables; the probability steps by which the system load level should be increased from the minimum level to the peak load level; the data for dividing the system into sub-systems when the load flow solution does not converge for an outage condition; and the maximum number of outages to be considered (either one or two).

The failure and repair rates of the generating units, transmission lines and transformers are required. A considerable amount of information on generating unit forced outage experience and descriptions of comprehensive recording procedure has been published[29,30,31]. The Statistical Analysis of System Outages Committee in the Western zone of the Canadian Electrical Association has prepared a reporting procedure[31] which has been accepted by the bulk of Canadian utilities. The object is to process the outage data digitally on a national basis and to determine the statistical distributions of the outage parameters. Two committee reports A.I.E.E.[32] and I.E.E.E.-E.E.I.[53] on line outages presented a survey of high voltage line outages with detailed analysis of the cause and effects. The first report[32] dealt with the 100 kV - 250 kV line performance record of 62 operating companies for about 10 years. The second report presented the 230 kV - 360 kV line performance record of 42 operating companies over a period of 14 years. This information is extremely useful in the design of transmission lines. Average failure rates for lines of different voltage classes as obtained from these reports are noted in Table 3.1. Unfortunately these reports do not contain any record of outage durations which are essential in a reliability study. The importance of data collection with the object of reliability evaluation should be realized. Data collection cannot be postponed till the development of acceptable reliability evaluation techniques.

3.6 Study of a Simple Hypothetical System

The calculated risk levels obtained using the two techniques given by Equations 3.1 and 3.3 will vary with changes in the number of load probability steps used and the maximum number of simultaneous independent outages considered in the study. The results are also affected by the utilization of constant power or constant admittance models for the individual loads. A simple hypothetical system was selected to investigate the effect of these changes, together with changes in the bus voltage limits and the addition of selected lines. The system is shown in Figure 3.2 and the data are given in Appendix 8.3. The risk levels obtained in terms of the probability of failure and the expected frequency of failure for loads at Buses 2,3,4 and 5 are shown in Table 3.2. Case 1 of Table 3.2 can be considered as the base case. Equations 3.1 and 3.2 have been used and the loads represented as constant admittances. A maximum of two simultaneous independent outages were considered for the system consisting of lines 1 to 6. The load model, represented by a straight line from the 100% to 40% load points was approximated by 10 equal probability steps. The minimum acceptable system voltage was 0.97

TABLE 3.1

Annual Failure Rates of Lines of Different Voltage Classes

No.	Voltage Class	Failures/100 miles (λ_f)	Reference
1	Subtransmission	4.50	
2	100 - 126 kV	13.60	
3	126 - 150 kV	5.99	
4	151 - 175 kV	6.07	No. 32
5	200 - 250 kV	2.83	
6	above 250 kV	1.26	
7	(2) to (6) above	9.11	
8	220 - 240 kV	1.1380	
9	287 - 300 kV	1.9943	No. 53
10	345 - 360 kV	4.7217	
11	(8) to (10) above	1.5000	
12	230 kV [λ= 0.285, λ'= 43.5 r= 4.43 hours]	0.607	
13	138 kV [λ= 0.468, λ'= 100 r= 8.95 hours]	1.210	No. 12
14	Transformer 230 kV/138 kV (r= 1 week)	0.038	

Note: λ = Failure rate under normal weather conditions. λ' = Failure rate under stormy weather conditions. λ_f = The composite failure rate assuming expected normal weather and stormy durations as 200 and 1.5 hours. r = expected repair duration, assumed to be the same in stormy and normal weather conditions.

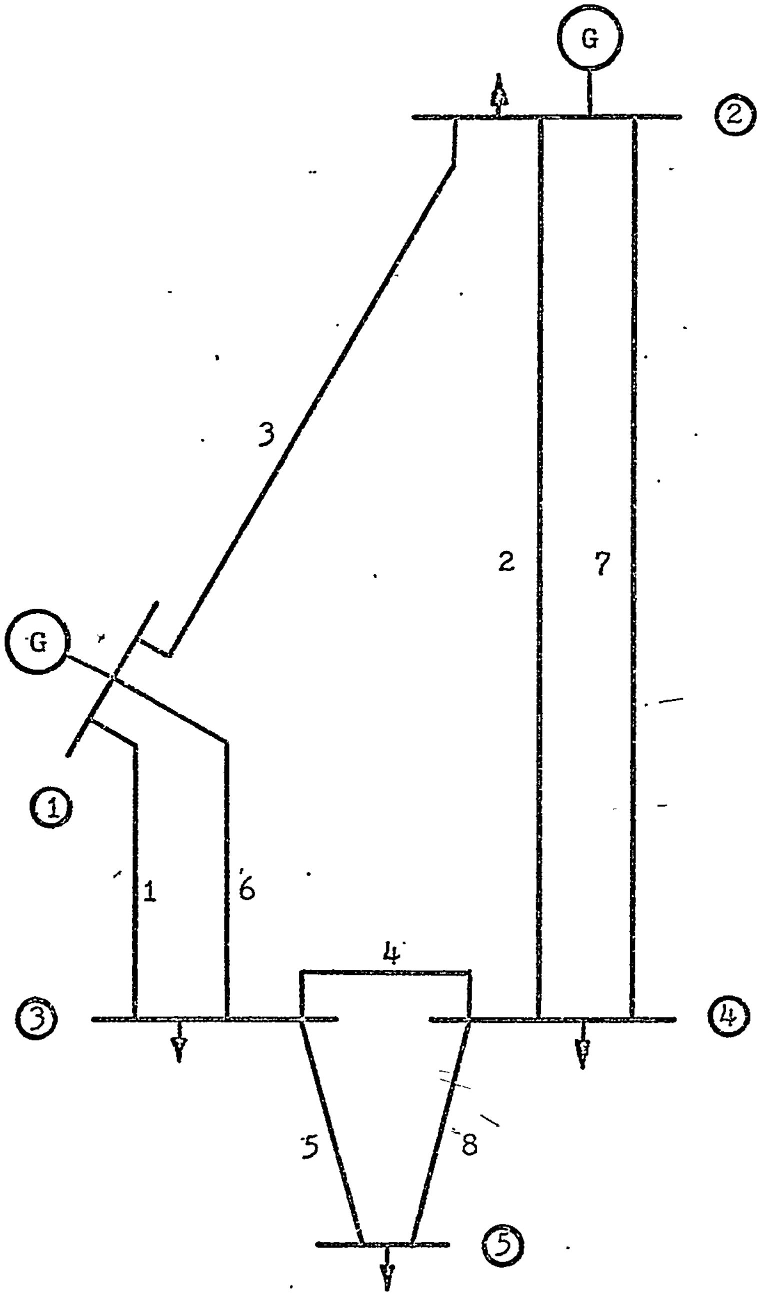


Figure 3.2 A Simple Hypothetical System

per unit and the maximum generation voltage 1.05 per unit.

The results of Case 2 were obtained using Equations 3.3 and 3.4. The risk at Bus 2 was found to be extremely low using this approach. This is partially due to the use of a maximum of two simultaneous independent outages. The risk at Bus 2 in Case 1 is basically a system generation contribution rather than an actual failure at Bus 2. This effect is eliminated in Case 2 in which the complete system capacity outage probability table is not used. Case 3 shows the increase in risk at Buses 3 and 5 when the system load models are changed to a constant power representation. The effect of changing the minimum acceptable voltage levels is shown in Cases 4a to 4h and plotted in Figure 3.3. The effect of removing a line and adding additional lines is shown in Cases 5,6 and 7. In Case 7 the risk levels are dominated by generation inadequacy as the transmission system adequacy is increased considerably.

In Case 8 the generating capacity was assumed to be completely reliable. The risk at Bus 2 is therefore zero in this case. The risk levels at other buses in the system are close to those obtained in Case 1 due to the high generating capacity reserve margin. The effect of increasing the system loads is shown in Case 9. If the increase in risk violates the system design criterion then the transmission facilities must be improved to reduce the risk to an acceptable value. This concept is the basis of the logical transmission planning program described in Chapter 4.

The results obtained by considering only single independent outages as shown in Case 11 are very close to those obtained in Case 1. This approach results in a significant saving in computer solution time. The bus risk levels in a system designed to be adequate for single contingency line outages would be approximately equal to the values obtained

TABLE 3.2

Bus Risk Levels in the System Shown in Figure 3.2

Normal Case: Lines 1 to 6 in service; up to 2 simultaneous independent outages considered; load distribution approximated to 10 steps; loads represented as constant admittances; minimum acceptable voltage at all buses: 0.97 per unit; maximum allowed voltage at generating buses = 1.05 per unit; Equations 3.1 and 3.2 used.

Case No.	Changes from the Normal Case	Bus 2 Probability	Bus 2 Expected Frequency	Bus 3 Probability	Bus 3 Expected Frequency	Bus 4 Probability	Bus 4 Expected Frequency	Bus 5 Probability	Bus 5 Expected Frequency
1	Normal Case	0.000062	0.0013	0.000937	0.8060	0.001729	1.5147	0.002075	1.8335
2	Generating unit outages considered individually (Equations 3.3 and 3.4)	0.000000	0.0000	0.000866	0.8114	0.001654	1.5315	0.001876	1.7335
3	Load representation as constant power	0.000063	0.0025	0.001500	1.3067	0.001730	1.5156	0.002638	2.3332
4a	Minimum acceptable voltage = 1.02 p.u.	0.000062	0.0016	0.004150	3.6707	0.006236	5.5331	0.005622	4.9929
4b	Minimum acceptable voltage = 1.01 p.u.	0.000062	0.0015	0.002910	2.5652	0.003872	3.4272	0.004047	3.5900
4c	Minimum acceptable voltage = 1.00 p.u.	0.000062	0.0015	0.001727	1.5111	0.002747	2.4239	0.002864	2.5364
4d	Minimum acceptable voltage = 0.99	0.000062	0.0013	0.001727	1.5096	0.001732	1.5195	0.002864	2.5361
4e	Minimum acceptable voltage = 0.95 p.u.	0.000062	0.0013	0.000376	0.3082	0.000942	0.8142	0.001514	1.3364

(Table cont'd.) Bus Risk Levels in the System Shown in Figure 3.2

Case No.	Changes from the Normal Case	Bus 2 Probability	Bus 2 Expected Frequency	Bus 3 Probability	Bus 3 Expected Frequency	Bus 4 Probability	Bus 4 Expected Frequency	Bus 5 Probability	Bus 5 Expected Frequency
4f	Minimum acceptable voltage = 0.93 p.u.	0.000062	0.0013	0.000092	0.0544	0.000377	0.3112	0.001231	1.0825
4g	Minimum acceptable voltage = 0.92 p.u.	0.000062	0.0013	0.000090	0.0505	0.000097	0.0626	0.001229	1.0787
4h	Minimum acceptable voltage = 0.91 p.u.	0.000062	0.0013	0.000090	0.0505	0.000095	0.0587	0.001228	1.0787
5	Line 6 removed	0.000064	0.0043	0.005108	4.5116	0.005561	4.9148	0.006242	5.5278
6	Line 7 added	0.000061	0.0022	0.000069	0.0155	0.000069	0.0169	0.001207	1.0552
7	Line 7 and 8 added	0.000061	0.0024	0.000067	0.0126	0.000067	0.0121	0.000068	0.0149
8	Generating capacity 100% reliable	0.0	0.0	0.000875	0.8040	0.001667	1.5128	0.002013	1.8315
9	Same as (8). All loads increased by 10%	0.0	0.0	0.001439	1.3070	0.001669	1.5164	0.002576	2.3334
10	Same as (9). Line 8 added	0.0	0.0	0.000877	0.8095	0.001440	1.3118	0.000881	0.8165
11	Single outages only considered	0.000062	0.0013	0.000903	0.7470	0.001689	1.4432	0.002025	1.7458
12	Load distribution approximated to 5 steps	0.000062	0.0013	0.000657	0.5586	0.002233	1.9598	0.001795	1.5856

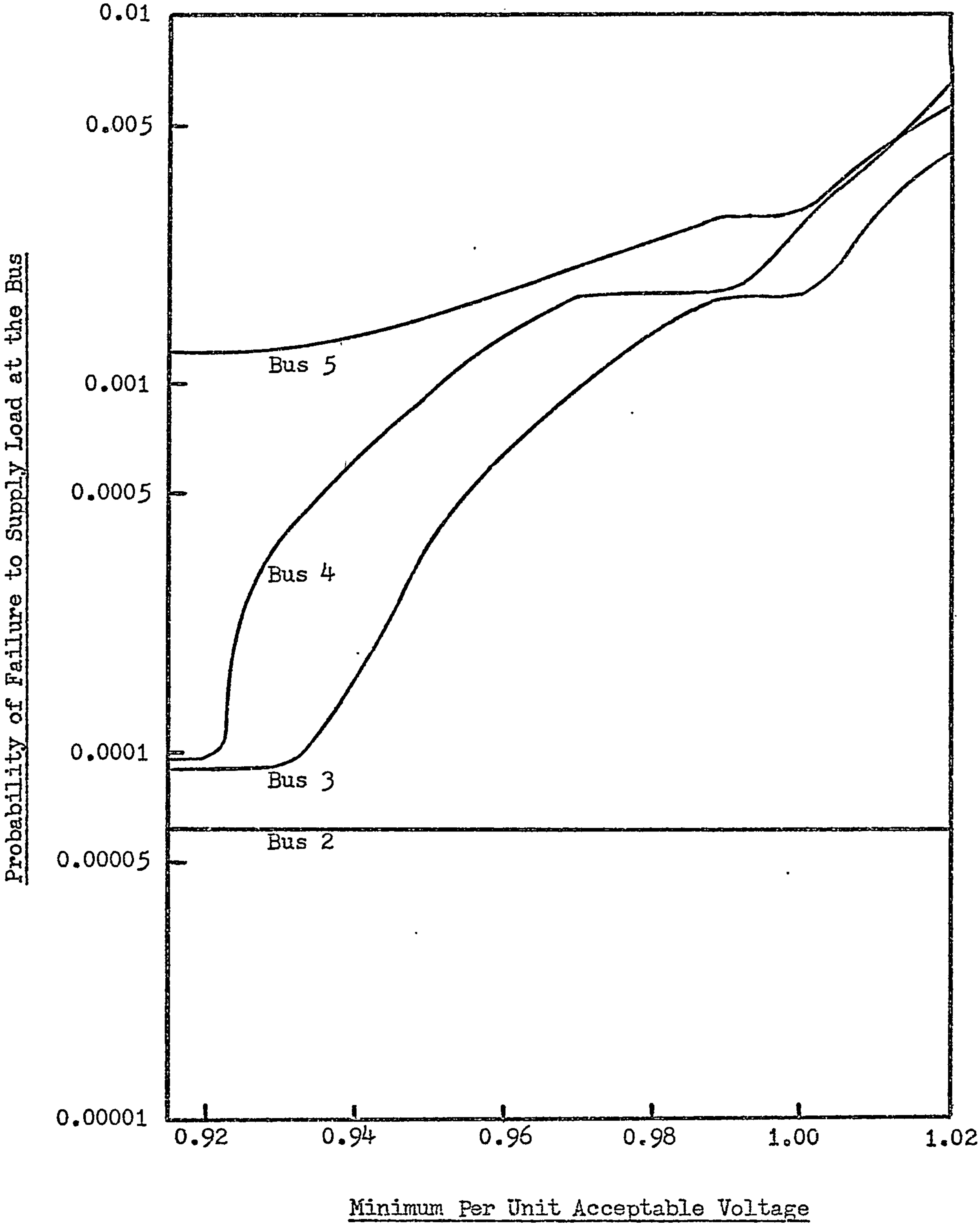


Figure 3.3 The Effect of Acceptable Minimum Bus Voltage on Risk Levels

by considering the generation adequacy only.

The effect on the calculated risk values of using a five step representation of the load characteristics is shown in Case 12. The results are significantly different from those obtained in Case 1. A reduction in the number of steps may be required in a large system to reduce the computation time to an acceptable value.

The study shows that the calculated risk can be significantly different with changes in the approach. It is therefore important to select an acceptable technique and to use it consistently throughout the planning period.

3.7 Application to a Practical System

The technique described has been applied to practical systems and it has been found that there are no additional complications other than the computation time increasing considerably. Methods of possibly reducing this time are indicated in Section 3.6.

The Saskatchewan System has been reduced to a major transmission network of two voltage levels 230 kV and 138 kV to illustrate the application to a practical system. The system configuration is shown in Figure 3.4.

The risk associated with the generating capacity was found to be relatively high compared to the contribution at any load point due to the transmission system. In order to correctly attribute any changes in reliability to changes in the transmission network, the generating capacity can be assumed to be completely reliable. This was also done in this case. The total system load in this study was taken as 895.7 MW, 165.5 MVAR and the minimum acceptable bus voltage assumed to be 0.95 per unit. Risk levels were evaluated by considering single outages and two

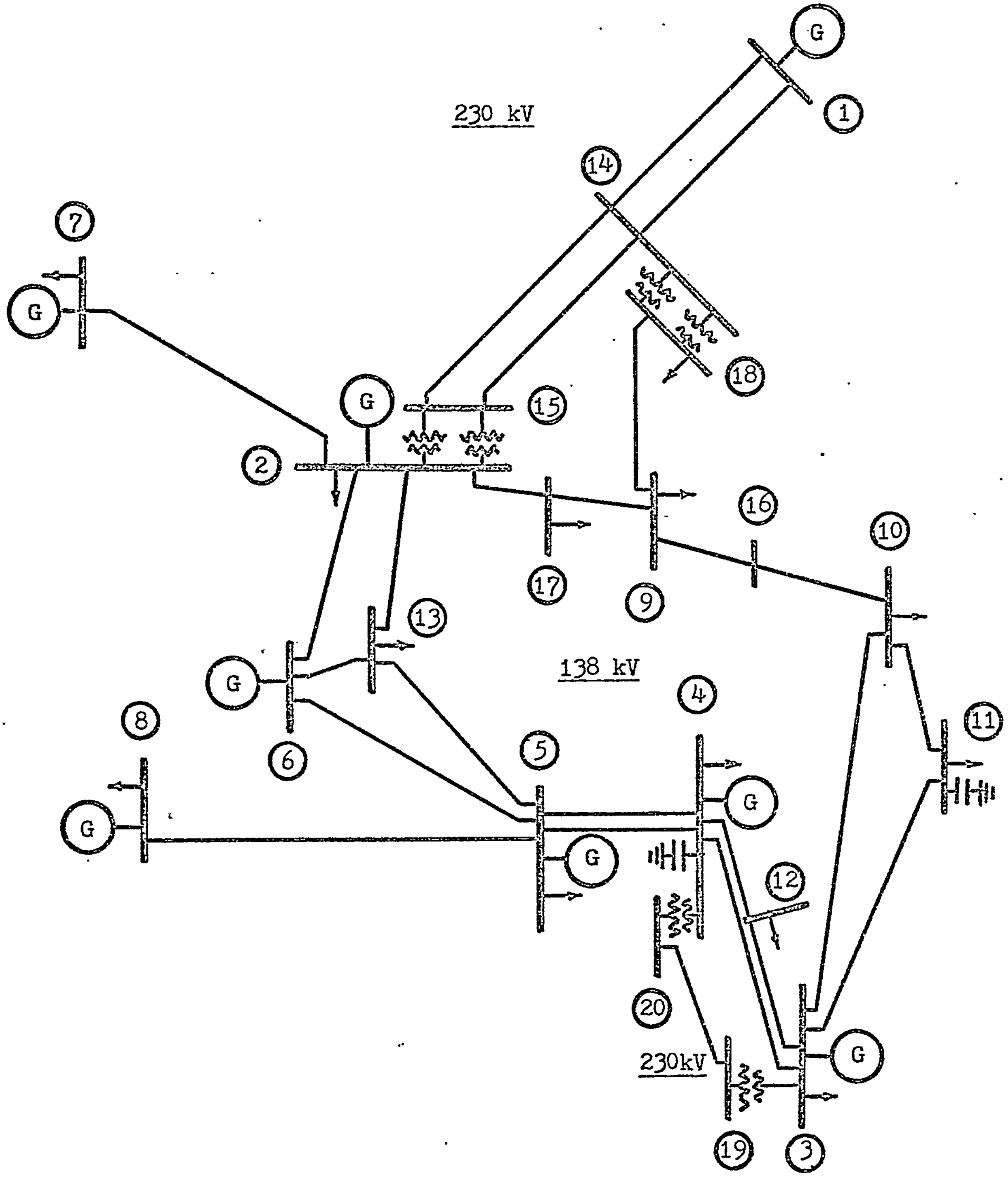


Figure 3.4 The Major Transmission Network of the Saskatchewan System

TABLE 3.3

S.P.C. Major Transmission Network Reliability

(a) Load and Generation Data

Bus	Peak Load MW	Peak Load MVAR	Minimum Load (percent of peak)	Total Generation MW	Total Generation ± MVAR
1	-	-	-	287	100
2	202.20	26.50	50	226.5	200
3	61.00	19.00	40	186.0	200
4	180.50	66.90	50	95.0	100
5	69.90	11.00	40	22.0	20
6	-	-	-	168.0	82
9	72.00	3.50	40	-	-
10	40.70	7.10	40	-	-
11	77.10	4.00	50	-	-
12	45.30	14.00	40	-	-
13	44.30	0.0	40	-	-
17	38.70	13.50	40	-	-
18	64.00	0.0	40	-	-

Note: Buses 7 and 8 in Fig. 3.4 are not included in the study and instead these loads are considered at Buses 2 and 5. The 230 kV line and transformers between Buses 3 and 4 are also not included in the study.

TABLE 3.3(b)

The Bus Risk Levels

Minimum acceptable voltage = 0.95 p.u.

No. of probability steps = 3 and 5

100% Generating capacity reliability assumed

	Single Outages No. of Prob. Steps = 5		Single Outages No. of Prob. Steps = 3		Two Outages No. of Prob. Steps = 3	
Bus No.	Probability	Expected Freq.	Probability	Expected Freq.	Probability	Expected Freq.
2	0.000000	0.0000	0.000000	0.0000	0.000002	0.0025
3	0.000000	0.0000	0.000000	0.0000	0.000000	0.0006
4	0.000000	0.0000	0.000000	0.0000	0.000001	0.0014
5	0.000000	0.0000	0.000000	0.0000	0.000003	0.0061
9	0.000928	0.9167	0.000985	0.9730	0.001026	1.0295
10	0.002004	1.9794	0.002113	2.0875	0.002179	2.1825
11	0.002354	2.3255	0.002174	2.1471	0.002242	2.2469
12	0.000000	0.0000	0.000000	0.0000	0.000001	0.0015
13	0.000000	0.0000	0.000000	0.0000	0.000001	0.0020
17	0.000712	0.7033	0.000481	0.4752	0.000503	0.5001
18	0.000000	0.0000	0.000000	0.0000	0.000007	0.0019
Computer Time (IBM 360/50)	12 Minutes		7 Minutes		97 Minutes	

outages with three load probability steps and by considering single outages only with five load probability steps. The results are shown in Table 3.3. This study indicated that considering single outages alone saves considerable computer time and gives risk levels that are reasonably close to the more accurate values obtained by considering a maximum of two simultaneous independent outages. The error is relatively low at the more important high risk points.

3.8 Subtransmission System Reliability

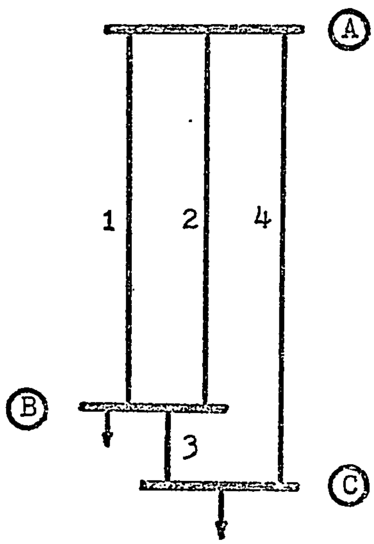
Each subtransmission system is usually fed from a single bus at a bulk-power station or at a generating station and feeds one or more distribution stations. The neighbouring subtransmission systems are normally connected to each other electrically only through the major transmission system. They can be purely radial, looped or networked systems. The study of the major transmission network becomes complicated, with respect to both reliability evaluation and planning, if all the subtransmission systems are included. The studies of the two networks have to be approached separately and their planning should be coordinated from the reliability viewpoint.

The transmission system reliability evaluation techniques described in Section 4.1 can be used directly for radial or looped subtransmission systems. For more complicated networks, the conditional probability approach may be necessary using load flow techniques. As discussed in connection with the Markov approach in Section 4.1, the effect of storms is negligible in systems which are not 100% redundant. This is illustrated in the study of the simple system shown in Figure 3.5. There are 32 possible states for four lines subjected to a normal and stormy fluctuating environment. The limiting state probabilities were evaluated for failures during storms of 0, 20 and 40 percent using the technique shown in Reference 10. The Gauss-Jordon method was used to solve the simultaneous linear equations. The following data have been used in this example.

Average failure rate	= 0.05 failures/mile
Average repair duration	= 7.5 hours
Normal weather duration	= 200 hours
Stormy weather duration	= 1.5 hours

The existence probabilities for the various outage combinations are shown in Table 3.4. Assuming equal loads at Buses B and C in Figure 3.5, the risk in terms of the probability of failure is computed for line carrying capacities equal to 100% and 80% of each load. The load duration characteristic is approximated by a straight line joining the 100 and 50 percent peak load points. The results noted in Table 3.4 show that if the conditional probability of load exceeding the remaining capacity under a single line outage is reasonably high then the effect of storm associated failures is negligible.

Figure 3.5 A Simple Subtransmission Network



Line	Length, miles
1,2	10
3	2
4	12

TABLE 3.4

Risk Levels in the Subtransmission Network Shown in Figure 3.5

(a) $P(B_j)$ and PL_j of Equation 3.1

		$P(B_j)$ With Storm Associated Failures of			PL_j At Redundancy			
					100%		80%	
j	B_j Lines Out of Service	0	20%	40%	Load B	Load C	Load B	Load C
1	Nil	0.99854590	0.99854704	0.99855061	0.0	0.0	0.0	0.0
2	1	0.00042746	0.00042695	0.00042534	0.0	0.0	0.4	0.4
3	2	0.00042746	0.00042695	0.00042534	0.0	0.0	0.4	0.4
4	3	0.00008549	0.00008539	0.00008507	0.0	0.0	0.0	0.4
5	4	0.00051295	0.00051233	0.00051040	0.0	0.0	0.4	0.4
6	1,2	0.00000018	0.00000033	0.00000080	1.0	1.0	1.0	1.0
7	1,3	0.00000004	0.00000007	0.00000016	0.0	0.0	0.4	0.4
8	1,4	0.00000022	0.00000040	0.00000096	1.0	1.0	1.0	1.0
9	2,3	0.00000004	0.00000007	0.00000016	0.0	0.0	0.4	0.4
10	2,4	0.00000022	0.00000040	0.00000096	1.0	1.0	1.0	1.0
11	3,4	0.00000004	0.00000008	0.00000019	0.0	1.0	0.0	1.0
12	1,2,3	0.00000000	0.00000000	0.00000000	1.0	0.0	1.0	0.4
13	1,2,4	0.00000000	0.00000000	0.00000001	1.0	1.0	1.0	1.0
14	1,3,4	0.00000000	0.00000000	0.00000000	0.0	1.0	0.4	1.0
15	2,3,4	0.00000000	0.00000000	0.00000000	0.0	1.0	0.4	1.0
16	1,2,3,4	0.00000000	0.00000000	0.00000000	1.0	1.0	1.0	1.0

(b) Risk of Probability of Failure

	Risk			
	100% Redundancy		80% Redundancy	
Storm Associated Failures	Load B	Load C	Load B	Load C
0	0.00000062	0.00000066	0.00054780	0.00058204
20%	0.00000113	0.00000121	0.00054768	0.00058191
40%	0.00000272	0.00000291	0.00054728	0.00058150

The risk obtained for the scheme shown in Figure 3.5 is a conditional risk assuming complete reliability of supply at Bus A in the major transmission network. The risk of supply failure at Bus A, however, can be included in the overall risk evaluation at Bus B or C as follows:

Risk of probability of failure at Bus B = $(1 - P_A) \cdot P_B + P_A$

$$\approx P_B + P_A \qquad 3.5$$

Similarly risk at Bus C $\approx P_C + P_A$ 3.6

where

P_A = Probability of failure to supply load at Bus A due to an inadequate major transmission network or to a generating capacity deficiency

$(1 - P_A)$ = Probability of availability of supply at Bus A

P_B = Probability of failure due to subtransmission inadequacy alone at Bus B

P_C = Probability of failure due to subtransmission inadequacy alone at Bus C

The resulting reliability at a distribution load point is dependent on the system generation, the major transmission network and the subtransmission system reliabilities. All aspects must be considered in the optimum utilization of available capital.

4. TRANSMISSION PLANNING

4.1 Transmission Planning Methods

4.1.1 General

The development of the transmission system and the associated costs are influenced considerably by the location of the future generation. Transmission planning can be divided into two general catagories of short range planning for a four to five year period and of long range planning for a fifteen to twenty year period. In short range planning, the system is tested for stability using rigorous stability criteria and for flexibility of operation under emergency conditions. The lead time associated with minimizing the uncertainty in the system requirement is dependent upon the design and construction of the system improvements. The object in long range planning is to select the most desirable transmission network for each generation expansion pattern under consideration. Both economics and reliability considerations decide what is the most desirable transmission network. The ultimate selection of the generation expansion plan is made by considering the transmission as an integral part of the total cost.

Transmission planning can be divided into the following three phases: testing the adequacy, the planning logic and costing the various transmission improvements and additions. These aspects are discussed later in this chapter.

There are four basic techniques which can be used to test the adequacy of a transmission network. They are as follows:

1. Fencing technique
2. Linear programming techniques
3. D.C. power flow method
4. A.C. load flow analysis

These methods are briefly described in the following sections.

4.1.2 Fencing technique

The paper[14] reporting the first application of this technique to practical systems using digital computer programs appeared in 1964. This approach is based on the philosophy that there is, in general, a fairly constant relation between the external transmission capability of any area of a system and the net load or generation in that area.

Testing of the transmission adequacy is performed by placing an imaginary fence around a portion of the network. The circuits delivering power into or out of the fenced area are noted and the total transmission capability into the fenced area is obtained using an average rating for each type of circuit. This transmission capability is compared with the net load or net generation within the fenced area to determine if the transmission network is adequate. The transmission adequacy of all portions of the system is checked by a proper selection of the areas being fenced.

The average rating of the circuits used to find the transmission capability into a fence is established by observing the average power carried by such circuits on the system. It was reported[14] that the rating is one half of the normal rating and a value even lower than this may be necessary in the case of longer transmission lines based on stability or voltage considerations.

The transmission adequacy at regular intervals of the planning period is checked for load growth, generating capacity additions and interconnections. The system is divided into a number of centers which are either points where power enters or leaves the transmission system or important junction points for several transmission circuits. While testing the transmission adequacy if any center is found to have a transmission capability less than its net load or generation, it is called a deficient center. A general policy of increasing the transmission capability into a deficient center with net load is to build lines from it in the direction of a center where generating capacity is being added. If generating unit or interconnection additions result in a deficient center with net generation in a fence, the centers outside the fence with high ratios of load to transmission are favoured for building lines, as these centers will probably require new circuits in the immediate future.

4.1.3 Linear programming techniques

These techniques are applicable to a wide range of problems involving optimization of a linear function subject to restrictions which are in the form of linear inequalities. The basic method, which is known as the Simplex method was originally developed by Dantzig and is well illustrated in many books[33] and papers. The application of the method using digital computer to the design of power networks has recently gained some importance[34,35].

The initial data required for network design using linear programming techniques consists of the generation and/or load supplied by each station, the proposed circuits to connect the various stations and their rating and costs. The function to be minimized is the cost of the required circuits in the final network. The network optimization is based on certain specific constraints as in any other linear programming problem. These constraints are in the form of inequalities restricting the lines between pairs of stations to a maximum number according to the available right-of-way and specifying a minimum number of lines to be built into each station for better reliability of supply. Network design criteria other than minimum cost such as a minimum product of power and distance or a minimum circuit length could also be used.

As the number of stations increases, the number of variables and inequalities and therefore the computer storage requirements increase very rapidly. It may be necessary in a large system to reduce the number of variables by eliminating at the start, those paths along which circuit construction is either impossible or undesirable.

4.1.4 The d.c. power flow method

It has been assumed in the fencing technique that each circuit added into the network carries power equivalent to the average rating initially specified. In practical systems, however, power flows are governed by the network impedances and possibility of overload and light load conditions can exist for each system component. When the transmission system is in general limited only by thermal capability rather than by voltage drop, new facilities are added to relieve the overloads. In such systems power flows made on a d.c. basis were found to be satisfactory[4] in transmission planning.

4.1.5 A.C. load flow analysis

The system bus voltages and line loadings can be computed relatively quickly and accurately using conventional a.c. digital load flow techniques. Improvements are continually being made in these techniques[50] regarding speed of computation and the size of systems that can be handled. The most widely used method is the Gauss-Seidel approach[36]. Automated transmission planning using an a.c. load flow solution was first reported[5] in 1965. Using this approach both low bus voltage and line overload conditions are included in the justification of transmission improvements.

4.1.6 Method selected

Fencing techniques and linear programming techniques assume that each circuit carries a power load equal to its specified average rating. The average ratings assumed should have adequate margin for any contingency outages. These techniques are more suitable for systems in which load and generation are distributed in such a way that desired line loadings are possible. When loads are remote from the generating sources, however, the transmission system designed to be adequate by these techniques may not satisfy voltage levels at some load points. These techniques require less data for a planning study relative to the a.c. load flow method. This may be an advantage in some cases of preliminary planning.

The d.c. load flow method determines the approximate line loadings and therefore is an improvement over the fencing and linear programming approaches. A transmission system designed using this method will include overload considerations. The voltage criterion at all the load points, however, may not be satisfied using this method in some systems.

A.C. load flow analysis satisfies both low voltage and overload criteria and the solution can be obtained to any desired accuracy. The computation time will be considerably longer than that required by the other methods. It appears that this approach is now replacing the previous methods due to the need for a more sophisticated system representation and the availability of faster computers and improved a.c. load flow techniques. The a.c. load flow approach has therefore been chosen as the basic technique for transmission planning in this thesis.

4.2 Criteria for Transmission System Adequacy

4.2.1 Adequacy under normal operating conditions

The evaluation of transmission system adequacy is an important step in the planning of new facilities. The adequacy should be tested under both normal and emergency operating conditions. Normal operating conditions imply that all generating units, transformers and transmission lines are available for service. The transmission facilities should be adequate to satisfy the bus voltage levels and the line loadings under these conditions. New facilities should be added to alleviate any unacceptable bus voltages and line or transformer overloads. A system operates for the bulk of the time under normal operating conditions and in accordance with the economic generation schedule. The duration of an emergency condition is usually relatively small. The economic generation schedule should therefore be included in the evaluation of transmission adequacy and both peak and off-peak load levels should be considered. A network designed for economic operation at the peak load level may not be adequate for economic conditions at some off-peak load level, depending on the cost of generation at the various plants and their location with respect to the loads in the system.

4.2.2 Adequacy under emergency conditions

Transmission facilities designed for adequacy under normal operating conditions will not usually be satisfactory under emergency conditions. Emergency conditions are triggered by outages of generating units, transformers or transmission lines due to component failures, storms or human errors. Outages of large generating units or heavily loaded lines or transformers can cause cascading failure of other facilities operating in parallel. The Northeast Power Failure on November 9, 1965 in the United States and in Canada[37,38] was one such cascading condition.

An emergency condition can be divided into two periods, the transient period and the steady state period. The performance of the system during the fault and immediately after clearing the fault can be predicted utilizing available transient stability analysis techniques. Improvements in these techniques are being constantly studied for accurate simulation of voltage regulator action and governor response in predicting the system performance during the post-fault period. Operating policies and manual and automatic measures[37,38,41] to reduce the possibility of the system collapsing under emergency conditions are extremely important in planning. The conditions that finally dictate the design of the transmission system are stability and flexibility of operation.

The following criteria for stability analysis in power systems have been suggested in a recent Advisory Committee Report[38,41] to the Federal Power Commission.

" a) The outage of any power plant, including the largest, on any one of the interconnected systems, both under steady-state conditions and following a three-phase fault.

b) The outage of the most critical transmission line on any one of the interconnected systems, as a result of a three-phase fault, during the outage of another critical line on the same or on an adjacent system.

c) The outage of all transmission circuits on any one common right-of-way as a result of simultaneous three-phase faults.

d) The outage of an entire transmission sub-station on any one of the interconnected systems.

e) The sudden dropping of a large load or a major load center.

f) The effect of power swings arising from disturbances outside the individual system or coordination area. "

A similar set of criteria have been reported[40] as adopted by the member companies of the East Central Area Reliability Coordination Agreement (ECAR), which stretch from Indiana to Pennsylvania and from Michigan to Virginia with a total generating capacity of 40,000 MW.

In the author's opinion, only systems involved in a large interconnected pool may be in a position to achieve the system adequacy dictated by these rigorous criteria. The cost of the required improvements to satisfy these adequacy measures could be prohibitive in small systems with limited interconnections. As pointed out in Section 4.1.1 a rigorous system study considering stability aspects in transmission system design is only possible in short-range planning. It is not practical to include these details in a long-range planning study. It is possible, however, to consider the effect of outages during the steady state period in long-range transmission planning. This thesis is restricted to long-range transmission planning without any stability criteria. The effect of outages after the transient period is considered in testing the transmission adequacy.

It has been suggested that in long-range planning the transmission adequacy can be tested by considering the effect on the system of selected critically loaded component outages[4,5]. Outages of heavily loaded lines or transformers together with the largest generating unit are considered for this purpose. In general, the selection of these outages is influenced by the previous system experience and the intuition of the planning engineer. There is a possibility in this approach, of some critical outage conditions being ignored. An obvious method to avoid such a possibility is to consider the effect of all possible contingency outage conditions on the system. The possible outages are the single contingency outages, the double contingency outages and so on. The planning policy could be to design an adequate system for single contingency outages or double contingency outages or in general for a specified multiple contingency condition. In this approach the effect of all the component outages is considered equally, without giving any weight to the probabilities of occurrence. These methods do not include a quantitative measure of the level of reliability at the various load points. It is possible that transmission improvements may be made in areas which already have an adequate level of reliability and other areas which are deficient may be neglected.

This thesis proposes the use of a quantitative reliability criterion as a consistent approach to transmission planning. The composite system reliability measure includes all possible outages and considers the load as a probability distribution. In this approach the component outages are weighted by their probability of occurrence. The reliability indices at the load points can be evaluated using the techniques developed in Chapter 3, in terms of the risk of probability of failure or expected frequency of failure. Transmission network improvements are necessary if the risk at any load bus exceeds the acceptable value at the bus.

Any one of the variations in the reliability evaluation approach described in Chapter 3 can be used for transmission planning. The technique using Equations 3.3 and 3.4 is more accurate than using Equations 3.1 and 3.2. In certain cases, if the generating capacity inadequacy is high, it dominates the bus risk levels. The transmission system planned on the basis of these risk levels will not be a function of transmission network inadequacy. This is particularly true if the generating capacity inadequacy varies considerably during the planning period. This condition can be avoided using a conditional risk given that generating capacity is completely reliable. This risk properly reflects the transmission inadequacy and therefore provides a consistent basis for transmission planning. If the transmission facilities from a bus at which only generation is located are found to be adequate with the maximum available generation at the plant, the facilities will also be satisfactory for any reduced generation condition. The effect of generating unit outages therefore, need not be considered if transmission system adequacy is tested under maximum generation conditions. If a generating bus, however, is directly connected to a load, the transmission facilities from the bus should be designed for multiple generating unit outages.

In summary, the transmission planning procedure is as follows. The system should be planned first under normal operating conditions for economic operation at both peak load levels and off-peak load levels. The network should then be tested under selected generating schedules obtaining maximum available generation output at buses with generation alone and reduced generation due to generating unit outages at buses with both generation and load. The next step is to plan transmission improvements to alleviate high risk conditions. Planning under normal operating conditions before considering reliability levels is essential to save computer time. The number of times that reliability evaluation is to be performed will be reduced due to some possible transmission improvements being already included in considering normal operating conditions. The reliability indices can be obtained for the same economic generation schedule assuming all the generating units to be available. These indices are somewhat on the conservative side as discussed in Section 4.3. This is also true for the consequent transmission system improvements.

4.3 Economic Generation Schedule

4.3.1 General

The optimum generation schedule neglecting transmission losses is considered as the schedule for which the total input to the system in dollars per hour is a minimum. This condition is achieved when all the generating units are operated at the same incremental production cost[43].

$$\frac{dF_n}{dP_n} = \lambda \qquad 4.1$$

where

F_n = Input to plant n in dollars per hour

P_n = Output of plant n in MW

$\frac{dF_n}{dP_n}$ = Incremental production cost of plant n in dollars per MW-Hr

λ = Incremental cost of received power in dollars per MW-Hr

The value of λ is chosen such that

$$\Sigma P_n = \text{Total load} + \text{Transmission losses} \qquad 4.2$$

The correct method of obtaining the optimum schedule is by coordinating the incremental production costs and the incremental transmission losses. The incremental transmission losses must therefore be expressed in terms of the incremental costs. The minimum input in dollars per hour for a given received load is obtained when the incremental transmission losses are charged at a rate equal to the cost of received power[43]. The coordinating equation in this case is as follows:

$$dF_n/dP_n + \lambda\,(\partial P_L/\partial P_n) = \lambda \qquad 4.3$$

where

F_n, P_n, dF_n/dP_n and λ are the same as in Equation 4.1

P_L = Total transmission losses

$\partial P_L/\partial P_n$ = Incremental transmission loss in MW per MW, at plant n. Equation 4.3 can be written as:

$$dF_n/dP_n = \lambda(1 - \partial P_L/\partial P_n)$$

$$(dF_n/dP_n) \cdot 1/(1 - \partial P_L/\partial P_n) = \lambda$$

$$(dF_n/dP_n) \cdot L_n = \lambda \qquad 4.4$$

where penalty factor of plant n is given by:

$$L_n = 1/(1 - \partial P_L/\partial P_n) \qquad 4.5$$

The optimum generation schedule is determined using the penalty factors and a value of λ which satisfies Equations 4.2 and 4.4. The plant incremental production cost is multiplied by the plant penalty factor to include the effect of the transmission losses. Several different techniques[43-49] are available to obtain the plant penalty factors.

4.3.2 Methods of determining penalty factors

The plant penalty factor is a function of the incremental transmission loss at the plant as shown in Equation 4.5. Some of the methods available for computing the incremental transmission losses are briefly described in this section.

The classical method of determining penalty factors uses the transmission loss formula coefficients, which relate the losses to the plant power outputs. The transmission losses are given by[43]:

$$P_L = \sum_m \sum_n P_m B_{mn} P_n \qquad 4.6$$

where

P_m, P_n = Outputs of plants m,n

B_{mn} = Transmission loss coefficients i.e. a symmetrical array of N x N elements, where N is the number of generating plants.

The incremental transmission loss at plant n is given by:

$$\partial P_L/\partial P_n = \sum_m 2\, B_{mn}\, P_n \qquad 4.7$$

The loss formula coefficients are calculated for a specific transmission configuration and preselected operating conditions. The derivation is based on the following assumptions:

1. Bus voltages remain constant in magnitude and phase angle.
2. Individual loads remain as constant complex fractions of the total load.
3. The ratio of reactive to real power generation remains constant.

Loss formulas have been applied successfully to many systems. The computation of the plant penalty factors is simple and direct using the loss formula coefficients. A new set of coefficients must be calculated, however, when major changes take place in the transmission system or in the operating conditions. The method of evaluating loss formula coefficients using tensor theory, operating on the bus impedence matrix has been described in considerable detail in the literature[43,52].

A simple and direct method to determine the incremental losses as a function of the voltage phase angles and reactance/resistance ratios of the equivalent transmission path between the plants was presented in a 1954 publication[46]. One advantage of this approach is that any change in the system configuration by the addition of lines etc. can be readily taken into consideration. The two basic assumptions involved in the method are as follows:

1. When small amounts of power are exchanged between generating plants of a power system, the magnitudes of the bus voltages of these plants are unchanged. Phase angles of the plant bus voltages vary as required to produce the power exchange. The ratio of power and reactive power of the generating plants vary as required to maintain the bus voltages.

2. Multiple transmission paths between two generating plants may be represented by a single impedance, commonly known as the transfer impedance.

It has been shown[46] that the ratio of the incremental costs for two plants is a function of the X/R ratio between the plants and the tangent of half the difference between their respective voltage phase angles.

$$\frac{dF_2/dP_2}{dF_1/dP_1} = \frac{(K_{21} + \tan \theta_{21}/2)^2}{(K_{21} - \tan \theta_{21}/2)^2} \qquad 4.8$$

where

K_{21} = The X/R ratio of the transfer impedance between plants 2 and 1

θ_{21} = The difference between the voltage phase angles at plants 2 and 1

Comparison of Equations 4.4 and 4.8 shows that if plant 1 is taken as the reference, the penalty factor for plant 1 is 1.0 and that for plant 2 is

$$L_{21} = \frac{(K_{21} + \tan \theta_{21}/2)^2}{(K_{21} - \tan \theta_{21}/2)^2} \qquad 4.9$$

In general, if plant n is taken as the reference, the penalty factor for plant n is 1.0 and that for plant j is

$$L_{jn} = \frac{(K_{jn} + \tan \theta_{jn}/2)^2}{(K_{jn} - \tan \theta_{jn}/2)^2} \qquad 4.10$$

where

K_{jn} = The X/R ratio of the transfer impedance between plants j and n

θ_{jn} = The difference between the voltage phase angles at plants j and n

The accuracy of the results is influenced by the number and location of the intermediate generating plants between each plant j and the reference plant n and the variation in X/R ratios, K_{jn}. It has been shown[46] that in a line type arrangement of plants there is no appreciable error in the incremental losses due to the presence of the intermediate plants up to about 15 degrees of phase angle difference and relatively little error even at larger angles. The error decreases for networked systems with parallel paths between plants as the variation in the composite X/R ratios between the plants and the reference bus will be much less than in a line type arrangement.

The methods of calculating the penalty factors using loss formula coefficients or voltage phase angles require various assumptions. Digital load flow solutions can be utilized for accurate determination of the incremental transmission loss[43]. In this approach the change in the transmission loss $\Delta P_{Lj,n}$ is determined by swinging a small block of generation, ΔP_{Gj} between plant j and the reference bus n and performing load flow analysis. The outputs of the other plants remain unchanged. The incremental loss $\partial P_{Lj,n}/\partial P_{Gj}$ for plant j is given by the ratio $\Delta P_{Lj,n}/\Delta P_{Gj}$. The procedure is repeated with each plant and the penalty factors are computed using Equation 4.5.

4.3.3 Economic dispatch using penalty factors as functions of the voltage phase angles

The approach given by Equation 4.10 has been selected to obtain the economic generation schedule in the planning of transmission facilities. This approach is relatively simple and sufficiently accurate for the type of application. The method is particularly suitable in a transmission planning program as the penalty factors are modified each time a transmission improvement is made.

The subprogram for evaluating economic dispatch uses an iterative approach combined with a load flow analysis as shown in Figure 4.1.

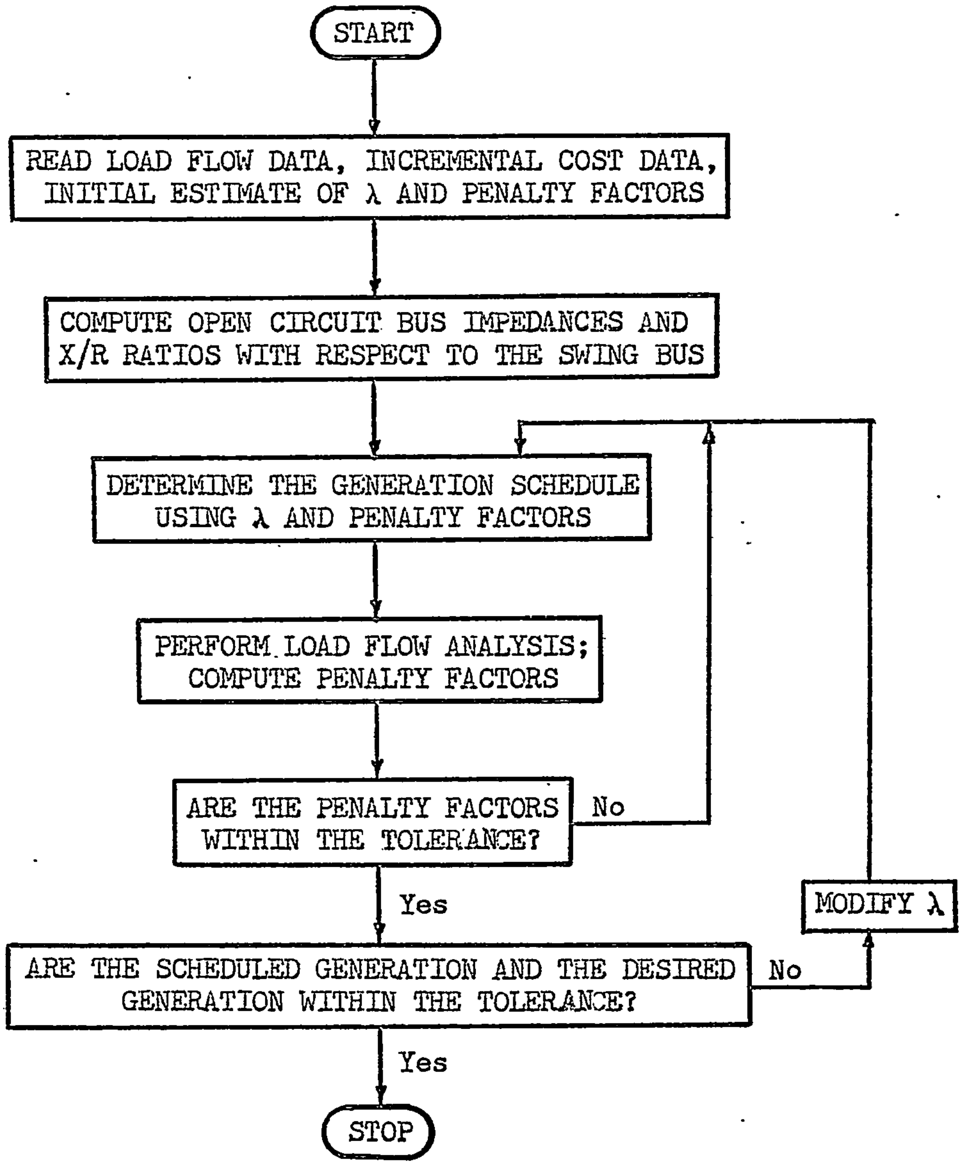


Figure 4.1 Flow Diagram of the Economic Dispatch Subprogram

The required data consists of all the information needed for conventional load flow analysis, the initial estimates of the plant penalty factors (they may all be 1.0) and the incremental production cost data of the generating plants. The incremental production cost vs. plant output curve is approximated by a single straight line. The incremental production cost function is therefore of the form,

$$dF_n/dP_n = F_{nn} P_n + f_n \quad \text{Dollars/MW Hr} \qquad 4.11$$

where

F_{nn} = The slope of the incremental cost curve of plant n approximated to a straight line

f_n = The intercept of the incremental cost curve of plant n

The initial step is to compute the X/R ratios of the bus impedances by selecting the swing bus as the grounded reference bus. All the sources, loads, line charging capacitance and synchronous condensers are open circuited. A known current (usually 1.0 per unit) is impressed at the first generating bus. The voltages of all the other buses are obtained by conventional load flow techniques. The ratio of the voltage at the first generating bus to the current impressed at that bus is the self-impedance with respect to the reference bus. This procedure is repeated at each generating bus and the self-impedances are obtained. The X/R ratios are calculated from the bus self-impedances and stored.

The initial generation schedule and the corresponding total generation are determined using Equations 4.4 and 4.11 using initial estimates of the penalty factors and the incremental production cost λ at the reference bus. A regular load flow solution is obtained with this generation schedule to calculate the voltage phase angles which are then used to determine the plant penalty factors from Equation 4.10. Each penalty factor is compared with the previous value and if the error is not within a specified tolerence, a new generation schedule is developed using the latest penalty factors. A load flow solution is obtained with this schedule and new penalty factors are computed. The procedure is repeated until the penalty factors converge. The total generation required to satisfy the load and the transmission losses as determined by the load flow solution is then compared with the generation scheduled using Equation 4.4. If the error is not within the specified tolerance, λ is changed using the equation[43],

$$\lambda_i = \lambda_{i-1} + (P_R^D - P_R^{i-1}) \frac{\lambda_{i-1} - \lambda_{i-2}}{P_R^{i-1} - P_R^{i-2}} \qquad 4.12$$

where

i = Next iteration

P_R^D = Desired generation from load flow solution

P_R^{i-1} = Total generation scheduled in iteration (i-1)

P_R^{i-2} = Total generation scheduled in iteration (i-2)

Using λ_i the entire procedure is repeated until the total generation scheduled is equal to the required generation within the specified tolerance. The final schedule obtained is the desired economic schedule.

The tolerance used in the penalty factor computation was 0.0001, which was also used in the load flow solution. For satisfactory convergence of remote plant penalty factors, each new value is averaged with the previous value for that plant in the first four or five iterations[5]. The tolerance used for convergence of the required generation was 0.01 MW. Figure 4.2 shows a simple system[43] for which penalty factors were obtained for comparison with the load flow method, the transmission loss formula method and the voltage phase angle method. The system data are shown in Table 4.1. The loss formula coefficients for the system are shown in Table 4.2. The penalty factors and the economic generation dispatch were evaluated by the three methods and shown in Table 4.3.

TABLE 4.1

The Data of the 3-Plant System Shown in Figure 4.2

Generation and loads are in per unit on 200 MVA base

Bus Number	Load	Maximum Generation	Voltage Magnitude	F_{nn}*	f_n*
1	0.430 + j0.100	1.0	1.015	0.02	2.5
2	0.234 + j0.029	1.0	0.980	0.02	2.5
3	0.000 + j0.000	1.0	0.953	0.02	2.5
4	0.181 + j0.015	-	-	-	-
5	0.087 + j0.060	-	-	-	-
Total:	0.932 + j0.204				

* Equation 4.11

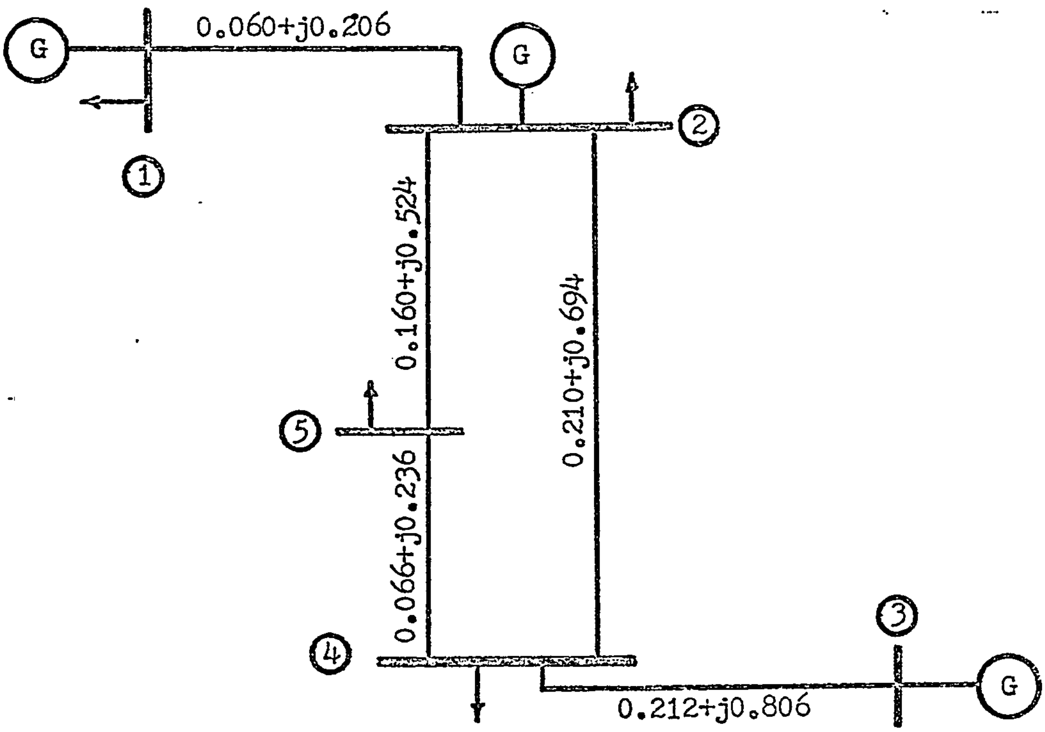


Figure 4.2 A 3-Plant System

TABLE 4.2

The Transmission Loss Formula Coefficients for the 3-Plant System Shown in Figure 4.2

	Plant 1	Plant 2	Plant 3
Plant 1	0.027251	- 0.003506	- 0.036788
Plant 2	- 0.003506	0.030896	- 0.005653
Plant 3	- 0.036788	- 0.005633	0.322950

TABLE 4.3

The Plant Penalty Factors of the System Shown in Figure 4.2

Bus Number	Penalty Factors by Method* 1	2	3	Economic Dispatch Generation by Method 1
1	0.985426	0.984100	0.986845	0.3643
2	1.0	1.0	1.0	0.3498
3	1.132514	1.119300	1.129177	0.2357

* 1 The voltage phase angle method
2 The loss formula coefficients method
3 The load flow method

The major transmission network of the Saskatchewan System for 1969 is shown in Figure 3.4. This configuration was used as a practical example to compare the penalty factors as functions of the voltage phase angles with those obtained by the load flow method. The assumed generation data are shown in Table 4.4. The slope of the incremental cost characteristic is zero for a hydro plant. This was taken as 0.00001 for computing purposes and the penalty factors are shown in Table 4.5.

TABLE 4.4

Generating Plant Incremental Cost Data Assumed for the Saskatchewan System (Figure 3.4)

Bus Number	Maximum Generation, MW	Type	F_{nn}*	f_n*
1	287.0	Hydro	0.00001	0.207
2	226.5	Thermal	0.00154	2.67
3	276.0	Thermal	0.00055	1.37
4	95.0	Thermal	0.00355	2.59
5	22.0	Thermal	0.01530	2.59
6	168.0	Hydro	0.00001	0.207

* Equation 4.11

TABLE 4.5

The Plant Penalty Factors for the Saskatchewan System

Peak Load: 947 MW, 175 MVAR, Year: 1969, Reference Bus = 2

Bus Number	X/R Ratio	Penalty Factors* Method 1	Penalty Factors* Method 2	% Error with respect to Method 1
1	7.59	1.070569	1.072167	0.149
2	-	1.0	1.0	0.0
3	3.95	0.939720	0.961222	2.290
4	3.78	0.919221	0.917906	0.143
5	3.77	0.935825	0.932026	0.405
6	3.74	1.040230	1.028867	1.090

* 1 The load flow method
2 The voltage phase angle method

4.4 Required Data for Transmission Planning

4.4.1 General

The digital computer program developed for automated major transmission planning is restricted to one or two assigned voltage levels. For example,

High voltage = 230 kV   Medium voltage = 138 kV

Transmission improvements are attempted by the program only in those networks at the two assigned voltage levels and the system is represented by the net generation and net load at these points. It is possible to include extra high voltage lines (i.e. 345 kV, 500 kV) in any year of the planning period by the input data. The required data includes all the information needed for load flow analysis and composite system reliability evaluation as listed in Section 3.5. All the parameters (failure rate, repair duration, rating, impedances etc.) of existing and proposed facilities during the planning period are required. The additional required data for generation, load, transmission and costing are listed as follows:

a) The date, size, type and location of generating unit additions and retirements. The generation addition requirements can be obtained by the loss of load probability approach as discussed in Section 2.1. This may be one of the many alternate expansion patterns to be considered in the planning.

b) Incremental production cost curves for generating plants.

c) Estimated future peak loads, with their distribution at various buses.

d) Capacitance that can be connected at a bus, in discrete steps with the specified maximum value, to alleviate bus low voltage conditions.

e) The capacity and location of future interconnections.

f) Any preplanned line and transformer additions.

g) The length, present occupancy and number of lines that can be constructed in the existing and proposed rights-of-way.

h) The possibility of reconductoring any existing line. This depends on whether the line outage during the reconductoring period can be tolerated. New conductor sizes if reconductoring is possible.

i) The possibility of looping or tapping any lines into a bus.

j) The possibility of converting any lines operating at a lower voltage into the higher voltage.

k) The cost of all types of circuit additions (lines, transformers and terminal equipment); the cost of other transmission improvements; fixed charge rate, interest and inflation factors.

l) Minimum acceptable bus voltages and maximum risk acceptable at each load point.

4.4.2 Data preparation for the computer program

The available generation, reactive power limits and forecast total load are specified for each planning year. The capacity outage probability tables are then modified to include the generating unit additions. The load distribution at the various buses, the bus load characteristics and the bus voltage limits are assumed to be the same as the initial values unless any changes are specified. Preplanned lines or transformers or the formation of new buses are included before entering the planning subprogram.

The Try Table specified in the data contains up to a maximum of five ordered suggestions for each bus in order to alleviate a low voltage or high risk condition at the bus. The planning engineer can use his experience through these suggestions, which are given priority over any other planning logic. The Try Table contains the specific information for transmission improvements such as looping a line into a bus, building a line between two buses, building a transformer between two buses or building a line and a transformer between two buses of different voltages.

Each bus has a set of possible connection points, up to a maximum of four, which are called the terminal priority (TP) buses. These can be nearby large capacity buses with right-of-way available for building lines. The object of designating these buses is to indicate the general direction of building lines. This could be towards a plant where generating capacity is added in the planning period. A medium voltage bus can have a high voltage bus as a terminal priority bus. Each bus has a code which identifies it as either a medium voltage bus, a high voltage bus or a medium voltage bus with a high voltage bus at the same station.

The right-of-way data can consider up to a maximum of three different routes between any two buses. Each route data contains the information on the type of line (conductor size) to be built, the number of double circuit towers that can be built, the availability of space for a line on an existing tower line and the distance in miles. It is assumed that all future construction is of the double circuit type. If a double circuit tower is built with a single line, the space is used in later planning years if required. These details are used for costing the new construction. With changes in the cost data it is also possible to estimate the costs based on the assumption that all the future lines are of the single circuit type. In the case of transformers between buses, the data contains information on the number of future transformers that can be built, the type (capacity) of transformers and any off-nominal tap to be represented. It is assumed that a line can be looped into a maximum of two buses. The line data contains the two bus numbers and their distances from one terminal of the line. The looped buses must be of medium voltage in the case of a medium voltage line and medium or high voltage in the case of a high voltage line.

The line data contains information regarding its route number and its voltage class which indicates whether it is high voltage, medium voltage or designed for high voltage but temporarily operating at medium voltage. The possibility of reconductoring is also specified.

The Type Data specifies the parameters of different capacity lines and transformers to be used in planning. Five different ratings can be considered. The parameters include the impedence per mile, the susceptance per mile, the current rating, the failure rate per mile and the repair rate in the case of lines and the impedence, the current rating, the failure rate and the repair rate in the case of transformers. The program selects a transformer of the same type as the line if they are to be connected in series. This requires the transformer rating to confirm to the line rating of the same type.

The data specifies the acceptable risk levels at the load points and the approach to be used in evaluating this risk. The generation schedule if other than the economic dispatch is to be used is also specified.

4.5 Transmission Planning Logic

4.5.1 The complete program

An attempt was made to make the transmission planning program logic as general as possible. Several possible transmission improvements are included in the planning logic. The program attempts the least expensive modification first followed by more expensive measures of alleviating the unacceptable system conditions. The data preparation is the most important step and it must include any standard transmission planning policies used by the company. If, however, there are some policies which cannot be handled by the program, modifications in the logic will be necessary.

In a planning technique reported[35] in 1966, the final year of the planning period was termed as the 'Horizon Year'. Before planning the transmission requirements for other years the horizon year transmission plan is obtained by linear programming techniques which do not require detailed data. The planning is then performed starting with the initial year to confirm to the horizon year plan. This method may not be satisfactory if the forecast for the horizon year is extremely uncertain. Planning for each year based on that years data alone may result in more desirable development through the period of study. It is of course necessary to revise the plans developed continually as more accurate forecast of load growth and estimation of costs are available.

The computer program for automated transmission planning is shown in Figure 4.3. The planning is performed at regular intervals either a month or year. The generating capacity additions, the load forecast, and any changes in the initial data are specified for each interval. The addition of lines and transformers to connect new loads or generating plants or the construction of extra high voltage lines or the conversion of any existing medium voltage lines to high voltage are specified by the input data before the program enters the planning logic for each interval and the program modifies the transmission network accordingly. If the medium voltage line specified to be converted has already been converted by the program as a transmission improvement in a previous year this input command is ignored by the program. If the economic generation schedule is to be used for transmission planning the program evaluates the dispatch as discussed in Section 4.4 obtaining the penalty factors as functions of the voltage phase angles. The specified generation schedule

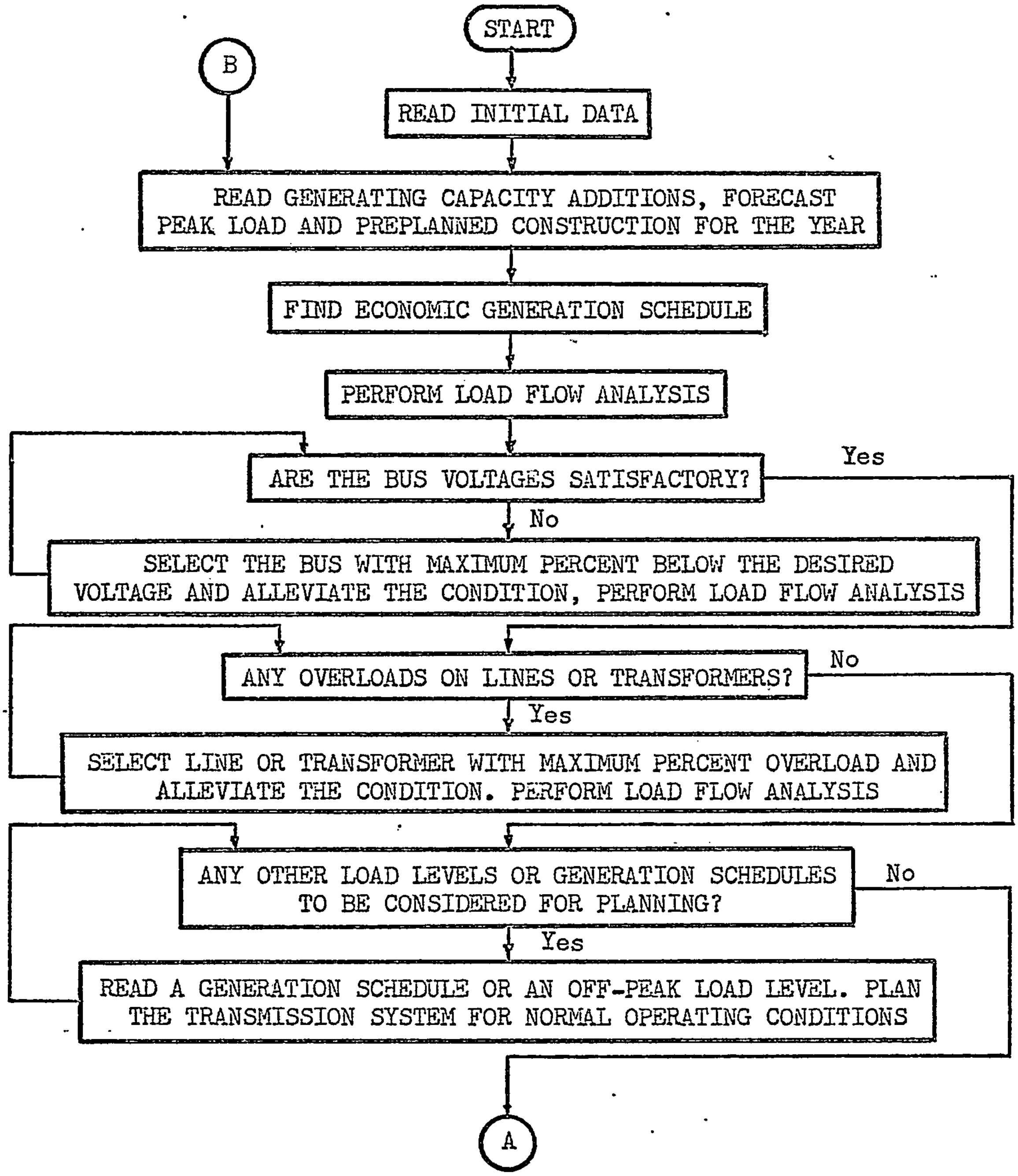


Figure 4.3 Flow Diagram of the Transmission Plannig Program

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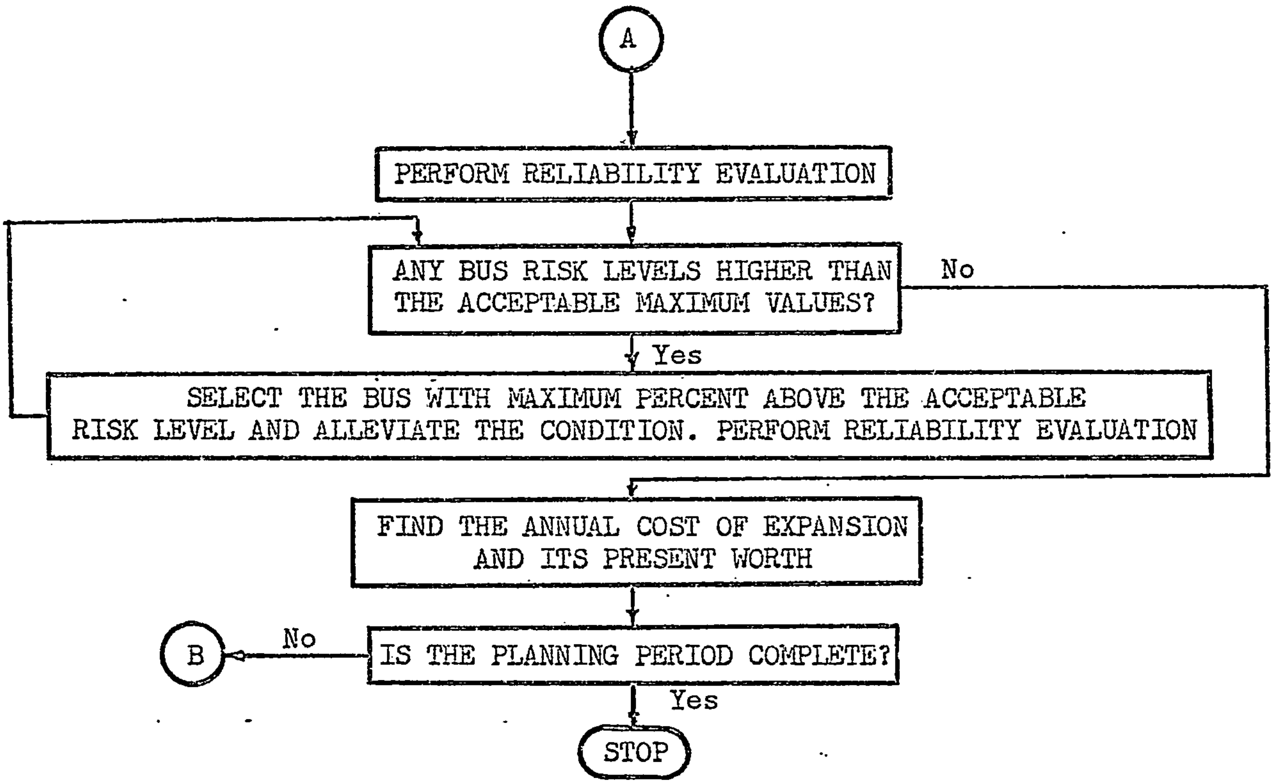


Figure 4.3 Flow Diagram of the Transmission Planning Program

(Continued from previous page)

is used in other cases. The load flow solution is checked for any bus voltages being less than the acceptable values. If there are any low voltage conditions, the program selects the bus with maximum percent low voltage and alleviates the condition. A load flow analysis is repeated to test the system for other low bus voltages. After eliminating all the low voltage conditions the program checks the line loadings. The line or transformer with maximum percent overload condition is considered and the overload is alleviated by transmission improvements. The system is tested again by a load flow analysis for other overload conditions. Repeating the procedure and eliminating all the overload conditions the program then performs a reliability evaluation. If any bus risk levels are higher than the acceptable values, the program chooses the bus with maximum percent unacceptable risk and alleviates the condition by transmission improvements. The procedure is repeated to improve bus reliability indices to acceptable levels. For each planning year the transmission adequacy is tested for off-peak load levels and at selected generation schedules. Planning for a single contingency outage criterion is also included in the program for the sake of comparison. The transmission improvements for each period of study are costed and the present worth is evaluated. The details of the planning logic and costing are discussed in following sections of this chapter.

4.5.2 Low voltage logic

If the voltage levels at some buses are found to be unacceptable, the program selects the bus with the maximum percent voltage below the desired value and attempts to alleviate the condition by transmission improvements. If the program has tried already once to alleviate low voltage on this bus and failed due to no improvements being possible then this bus is ignored and the next bus is considered. The various transmission improvements used in the low voltage logic are shown in Figure 4.4. If there are any Try Table suggestions these are attempted first. Otherwise capacitance is added at the bus equal to the specified increment if the total capacitance is less than maximum allowed. The terminal priority (TP) buses are then ordered in the decreasing ratio of the difference in the voltage magnitude of the TP bus and the low voltage bus to the right-of-way mileage between the TP bus and the low voltage bus. The TP buses are considered in this order before using them in transmission improvements. Three possible ways of looping a line are shown in Figure 4.5. In Cases (a) and (b) two line sections and in Case (c) three line sections are formed and these sections are renumbered as new lines. If looping is not possible, new facilities are built. If space is available on existing towers between two buses, this is utilized instead of building a new tower line. A new line is designed usually for the same voltage as of the buses between which it is built. If, however, it is specified in the data, an M/H line may be built between a pair of medium voltage buses. An M/H line is one which is designed for a high voltage but is temporarily operating at a medium voltage. The program may consider converting this line to high voltage as one of the transmission improvements in later years if required. The right-of-way availability is modified after building new facilities. If the bus with the low voltage condition is a medium voltage point at which a high voltage bus is located and the voltage of the high voltage bus is greater than the specified minimum value at the bus, a transformer is built between the two buses. If this is not possible, tapping a high voltage line through a transformer is attempted as shown in Figure 4.6. The next possible

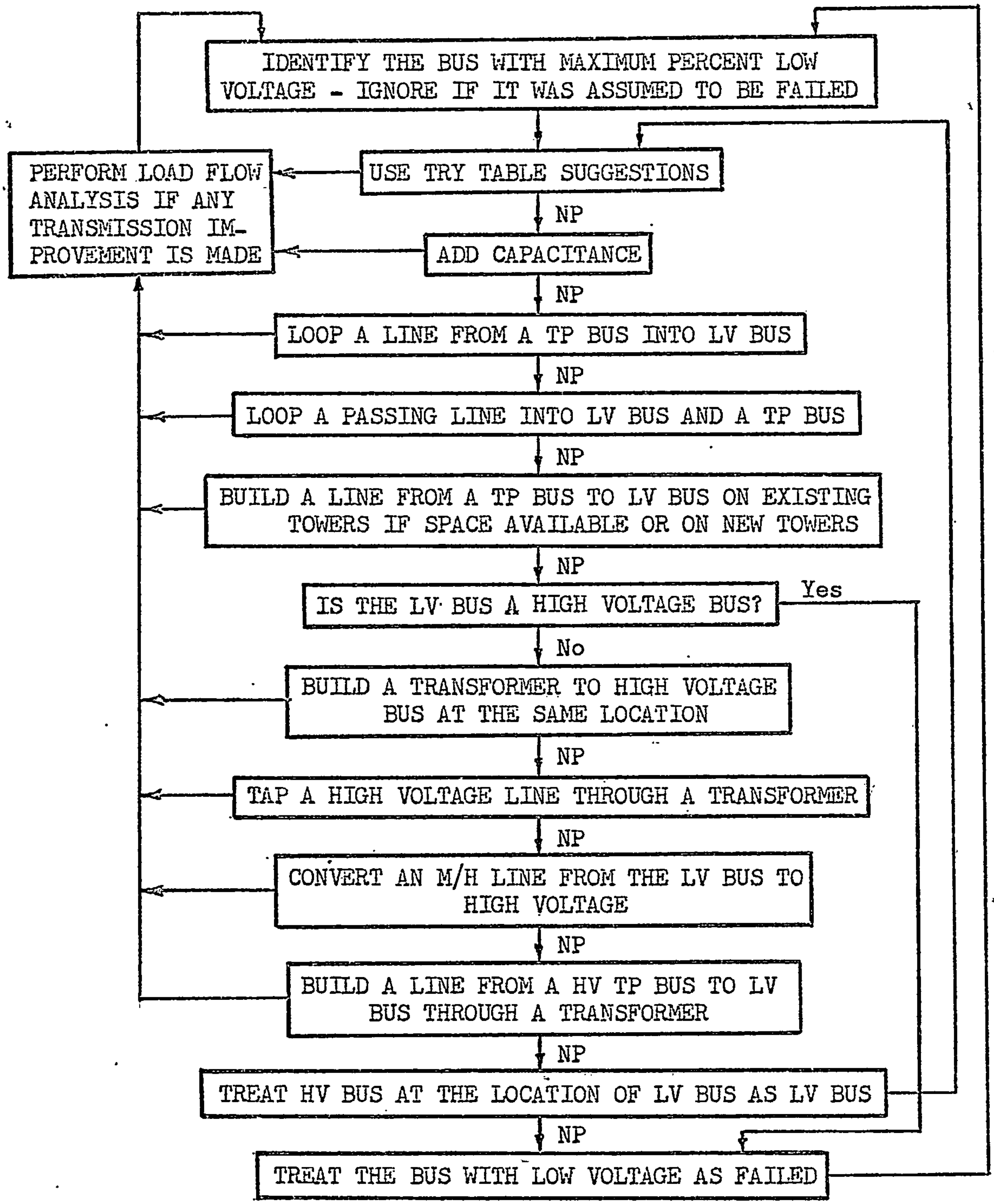


Figure 4.4 The Low Voltage Logic

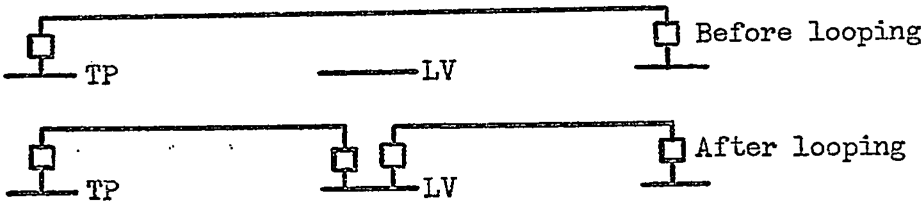
Legend:

NP - Not Possible
LV Bus - Bus with Unacceptable Voltage
TP Bus - Terminal Priority Bus
HV - High Voltage
M/H - Line designed for High Voltage but temporarily operating at Medium Voltage

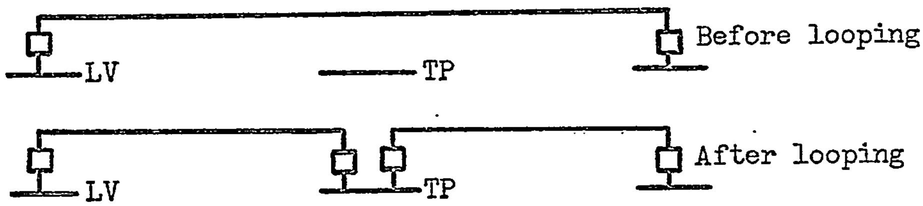
Figure 4.5 Different Possible Loopings

TP - Terminal Priority Bus LV - Bus with Low Voltage

(a) Looping a Line from TP Bus into LV Bus



(b) Looping a Line from LV Bus into TP Bus



(c) Looping a Passing Line into TP and LV Buses

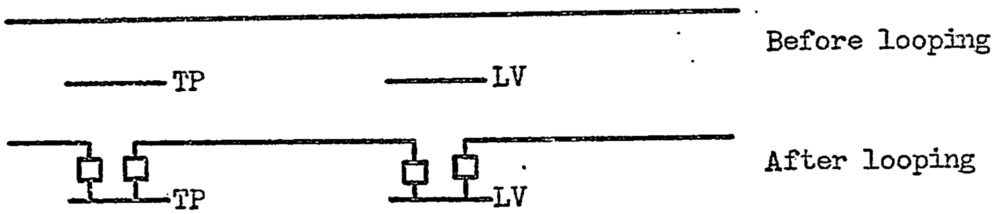


Figure 4.6 Tapping from a High Voltage Line Through a Transformer to LV Bus

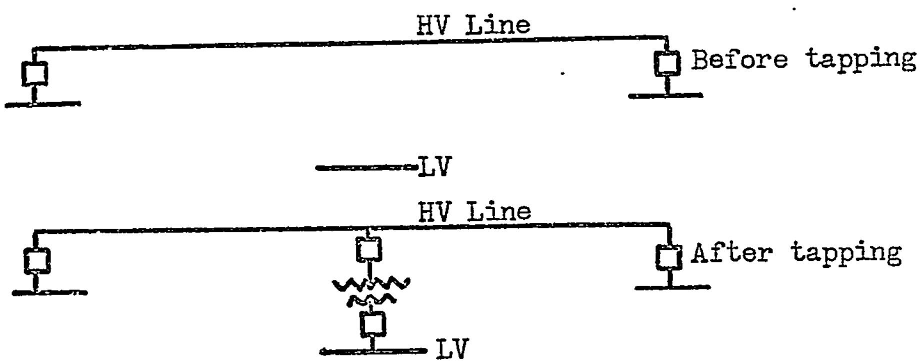
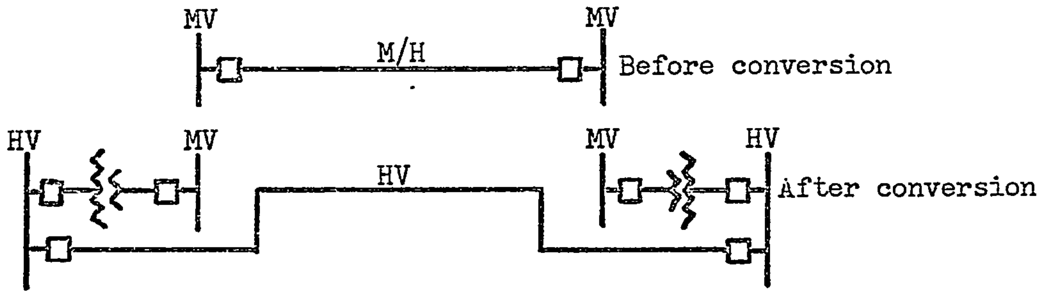
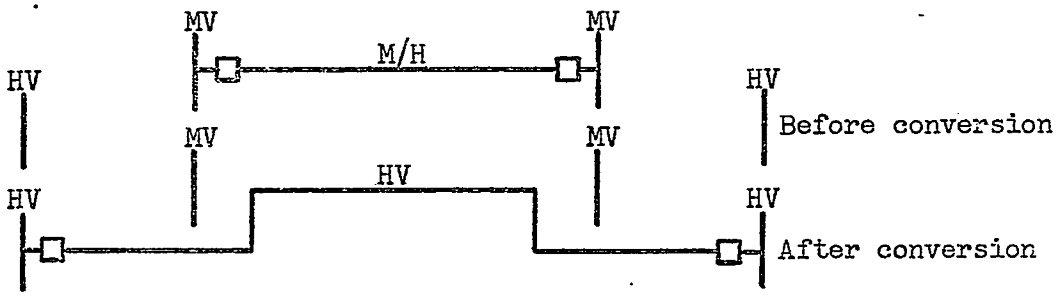


Figure 4.7 Conversion of an M/H Line to High Voltage

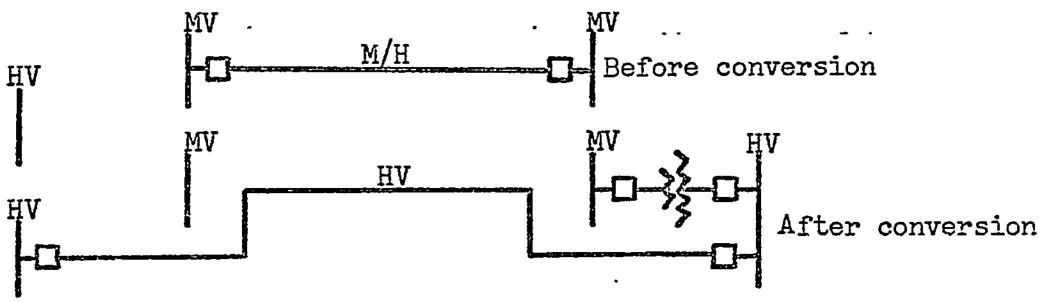
(a) No High Voltage Buses Available at the Terminals



(b) High Voltage Buses Available at Both Terminals



(c) High Voltage Bus Available at Only One Terminal



Legend:

HV - High Voltage
MV - Medium Voltage
M/H - Designed for High Voltage but Temporarily Operating at Medium Voltage

improvement is converting an M/H line from the bus with the low voltage condition to high voltage. Conversion involves changing the line parameters to confirm to high voltage operation and adding the required buses and transformers as shown in Figure 4.7. There are two possible ways of changing from medium voltage to high voltage operation between two buses by selecting proper data. One possibility, if there is an existing M/H line, is to convert the line to high voltage and build all future lines at high voltage. Conversion is usually cheaper than building a new line and is an effective means of improving voltage levels. If, however, there is only one line between the buses, conversion may increase the risk levels due to the transformers required in series with the line. The other possibility in such a situation is to build all future lines in the right-of-way as M/H lines and convert them to high voltage as required. If conversion is not possible, the right-of-way is checked for the possibility of building a line from a high voltage TP bus through a transformer to the medium voltage bus with the low voltage condition, as shown in Figure 4.8. If no improvements are possible the bus is ignored and the program starts with the next bus. If any of the improvements are attempted a load flow analysis is performed to check the bus voltage levels. After testing all the buses and modifying the transmission system, the low voltage condition at some buses may still remain. These conditions may not exist after complete planning to satisfy line loadings and reliability levels.

Figure 4.8 Building a Line from a High Voltage Terminal Priority (HV-TP) Bus to the Low Voltage (LV) Bus

4.5.3 Overload logic

The program enters the overload logic from the low voltage logic. If there are any overloaded lines or transformers the program selects the line or transformer with the maximum percent overload and attempts the transmission changes to relieve the overload. Only the transmission change which reduces the overload by more than 50% is retained. If a change is not possible or is unsuccessful, the program attempts the next possibility. After a successful transmission improvement, the program checks for further overloads and re-enters the overload logic if there are any overloads remaining. If any overload could not be relieved due to insufficient right-of-way facilities this condition is ignored until later.

A transformer overload is relieved by building a parallel transformer. Relieving line overload is attempted in several ways as shown in Figure 4.9. If possible, the line is reconductored to give a higher rating. Looping a line from one terminal of the overloaded line into the other terminal creates a prallel path. A passing line can be looped into the terminal of the overloaded line to which power is flowing. In either of these two looping possibilities, the line to be looped is of the same voltage as the overloaded line. Building a new line parallel to the overloaded line or from the terminal to which power is flowing over the overloaded line to a TP bus is based on the same rules as in the low voltage logic. Looping from M/H lines should usually be avoided, as additional transformers will be required at the looped bus when the line is converted later to high voltage. In the case of an overloaded line the conversion of an M/H line to high voltage can be attempted in two ways. In one case if there is an M/H line parallel to the overloaded line as shown in

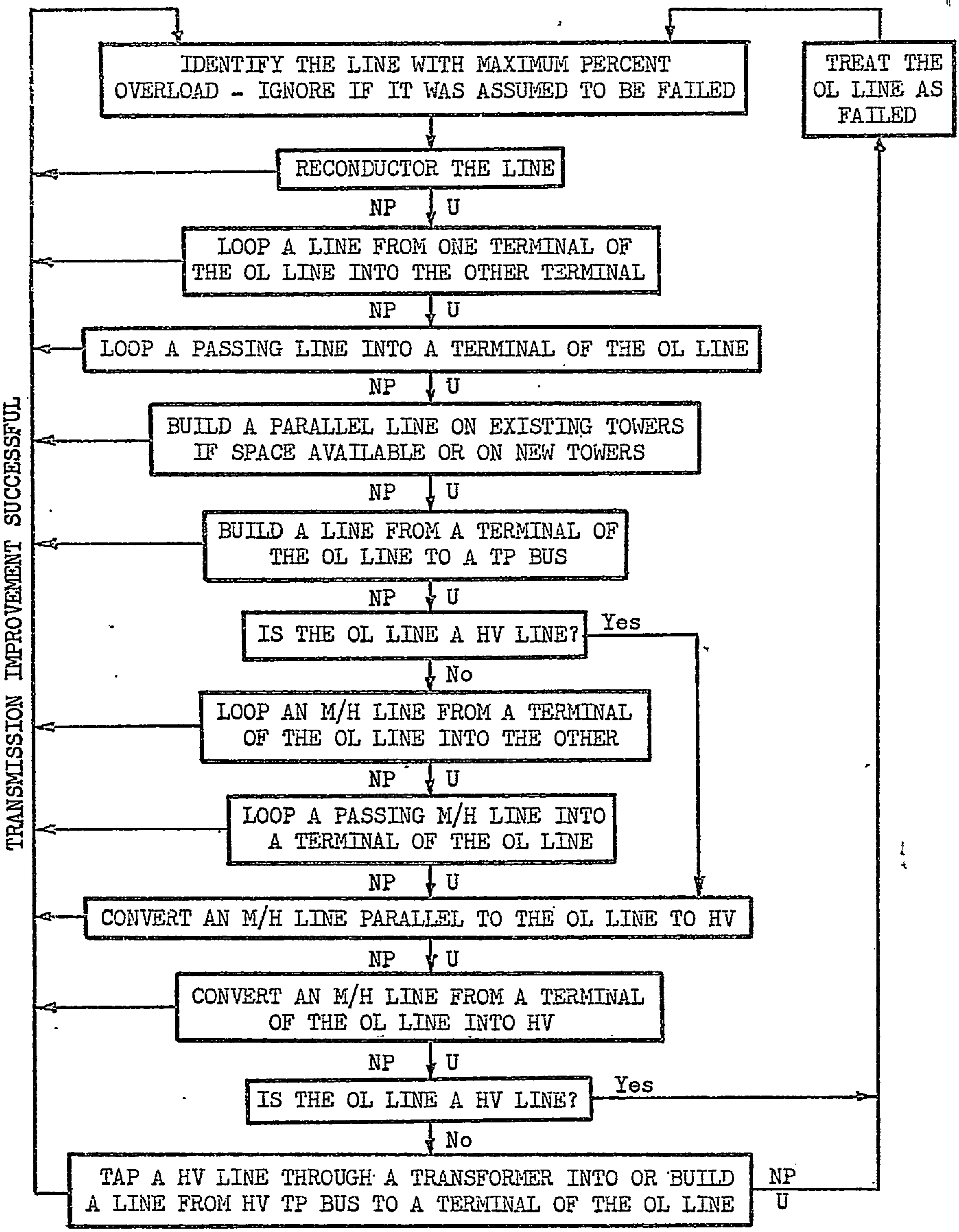


Figure 4.9 The Overload Logic

Legend:

NP - Not Possible
U - Unsuccessful
OL Line - Overloaded Line

Figure 4.10(a) it is converted to high voltage. In the other case, if there is an M/H line connected to one terminal of the overloaded line as in Figure 4.10(b) this line is considered for conversion. If the overloaded line is an M/H line it is converted to high voltage. The changes required in the network for conversion are shown in Figure 4.7. In the case of an overloaded medium voltage line, tapping a high voltage line or building a line from a high voltage TP bus through a transformer to the terminal to which power is flowing can be attempted similar to that shown in Figures 4.6 and 4.8.

4.5.4 Reliability criterion

The input data specifies the approach to be used for the reliability evaluation. After attempting to alleviate all the bus low voltage levels and line and transformer overloads, reliability levels are obtained. If any bus risk levels exceed the maximum acceptable values this condition is alleviated by a logic similar to the low voltage logic. The buses with undesirable risk levels are treated in the same manner as those with undesirable voltage levels and transmission improvements are performed as shown in Figure 4.4. Any low bus voltage levels or line overloads that could not be alleviated previously may have been satisfied in meeting the reliability levels. If, however, any of these unacceptable conditions cannot be alleviated due to insufficient right-of-way facilities, it is necessary to provide further right-of-way and re-examine the problem.

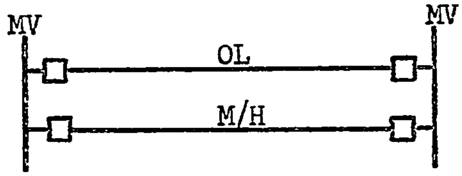
4.5.5 Single contingency outage criterion

The testing of transmission system adequacy under emergency conditions by considering the effect of contingency outages without using the

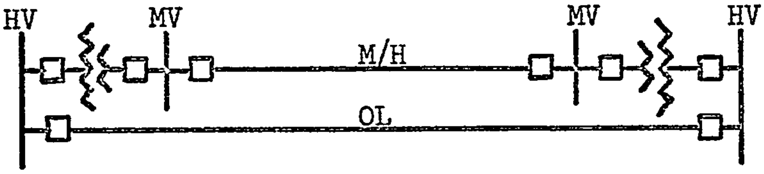
Figure 4.10 Conversion of an M/H Line to High Voltage for Alleviating Line Overload

(a) M/H Line Parallel to the OL Line

(i) Overloaded Line is a Medium Voltage Line

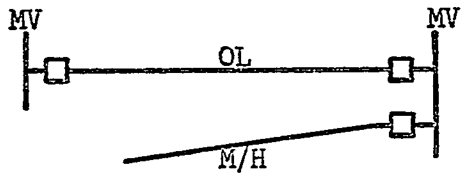


(ii) Overloaded Line is a High Voltage Line

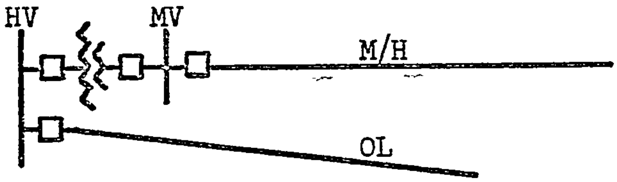


(b) M/H Line from One Terminal of the OL Line

(i) Overloaded Line is a Medium Voltage Line



(ii) Overloaded Line is a High Voltage Line



Legend:

OL - Overloaded Line
HV - High Voltage
MV - Medium Voltage
M/H - Designed for High Voltage but Temporarily Operating at Medium Voltage

probabilities is discussed in Section 4.2.2. The single contingency outage criterion was selected to compare with a quantitative reliability criterion for transmission planning. A subprogram (not shown in Figure 4.3) creates the single contingency outages in the decreasing order of percent loading of lines and transformers. The transmission system is tested under each outage condition for low bus voltages and overloads and improvements are made to alleviate these conditions by the low voltage logic and the overload logic.

4.6 Costing

4.6.1 The criterion of economic choice

The determination of a desirable plan from the study of several alternatives involves two steps. The first step is to determine which is the most economic plan and by how much. The second step is the selection of the most desirable plan in the light of the economics and other factors such as reliability which are not readily reducible to dollars. The revenue requirements are those revenues that must be obtained in order to recover all the annual costs including an acceptable rate of return on the investment.

$$\text{Acceptable returns} + \text{Expenses} = \text{Revenue requirements} \qquad 4.13$$

In order to define the business as successful the company must earn the minimum returns acceptable to the investors. The expenses include operating, maintenance, depreciation and taxes. Operating expense includes items sometimes mentioned separately such as fuel, insurance, general and miscellaneous expenses. A universally applicable criterion of economic choice is provided by Equation 4.13. The plan with the minimum revenue requirements is the most economic choice.

The annual revenue requirements in long range plans having different schedules for equipment installations may vary sustantially from year to year. A direct comparison of revenue requirements can then be made only by reducing the several series of figures to their lump-sum equivalent at a common date. The most convenient date is usually the initial year of the study period and therefore the amount is called the present worth. The present worth calculation treats all estimates to be 100% certain. This procedure reduces the importance of expenditures which are remote in time and thereby minimizes the importance of any associated errors.

The appropriate period for comparing the revenue requirements is an important question in regard to whether it should extend 'to eternity' perpetuity or should end earlier. There are two types of present worth factors. The factor, v^n which discounts a single payment at a specified date to its present worth is given by:

$$v^n = 1/(1 + i)^n \qquad \frac{(1+i)^n - 1}{(1+i)^n} = 1 - v^n \qquad 4.14$$

where

i = Rate of return, decimally

n = Number of interim compounding periods, usually years

The other factor, a_n which discounts a series of regular periodic payments (an annuity) to its present worth is given by:

$$a_n = \sum_{k=1}^{n} 1/(1 + i)^k = (1 - v^n)/i \qquad 4.15 \quad p + \frac{px}{(1+i)^n - 1}$$

This is simply the present worth of all the successive payments in each year from k=1 to k=n. If the period extends to eternity, $n = \infty$ and $a_n = 1/i$. For the usual values of rate of return, the present worth of a perpetual annuity is not much greater than the present worth for 50 to 60 years.

It has been shown[51] that the simple calculation 'to eternity' is a convenient method which gives results as meaningful as those obtained considering unit retirements, replacements and their costs. This does not assume eternal life for the enterprise but simply makes use of the fact that the value of a_n for n equal to the average unit life approaches the value as n tends to infinity. This approach provides a common end point for the study which eleminates the need to adjust for inequalities between alternatives at the terminal date, which is necessary when the study is ended in a finite period. Future price level changes are relatively unimportant in problems of this kind. If the investment cost of any construction in a year y is C, the present worth of the annual charges 'to eternity', using Equation 4.15 is given by:

$$\text{Present worth} = C.f^y.r.v^y/i \qquad 4.16$$

where

C = The cost construction in year y as estimated in the initial year

f = The annual inflation factor, decimally

r = The revenue requirement, decimally

For example, if $i = 0.075$, $r = 0.11$ and $f = 1.02$,

$$\text{Present worth} = 1.47 \times 0.95^y \times C$$

The present worth factor v^y assumes that annual payments are made at the end of each year.

4.6.2 Cost data

The input data to the computer program includes the cost of the various transmission improvements as listed as follows:

a) The construction of double circuit tower lines per mile with one line only and the stringing of the additional circuit on the existing towers. High and medium voltage levels are considered including five different line ratings.

b) The above data for two extra high voltage levels of one specified rating.

c) Transformers, high voltage to medium voltage, of five different ratings.

d) Transformers of one specified rating from extra high voltage to medium voltage.

e) Circuit breakers of one specified rating for each of the four voltage levels.

f) The cost of converting an M/H line to high voltage, looping a line into a bus and capacitor installation per MVAR.

g) The rate of interest, annual charges on investment and annual inflation factor.

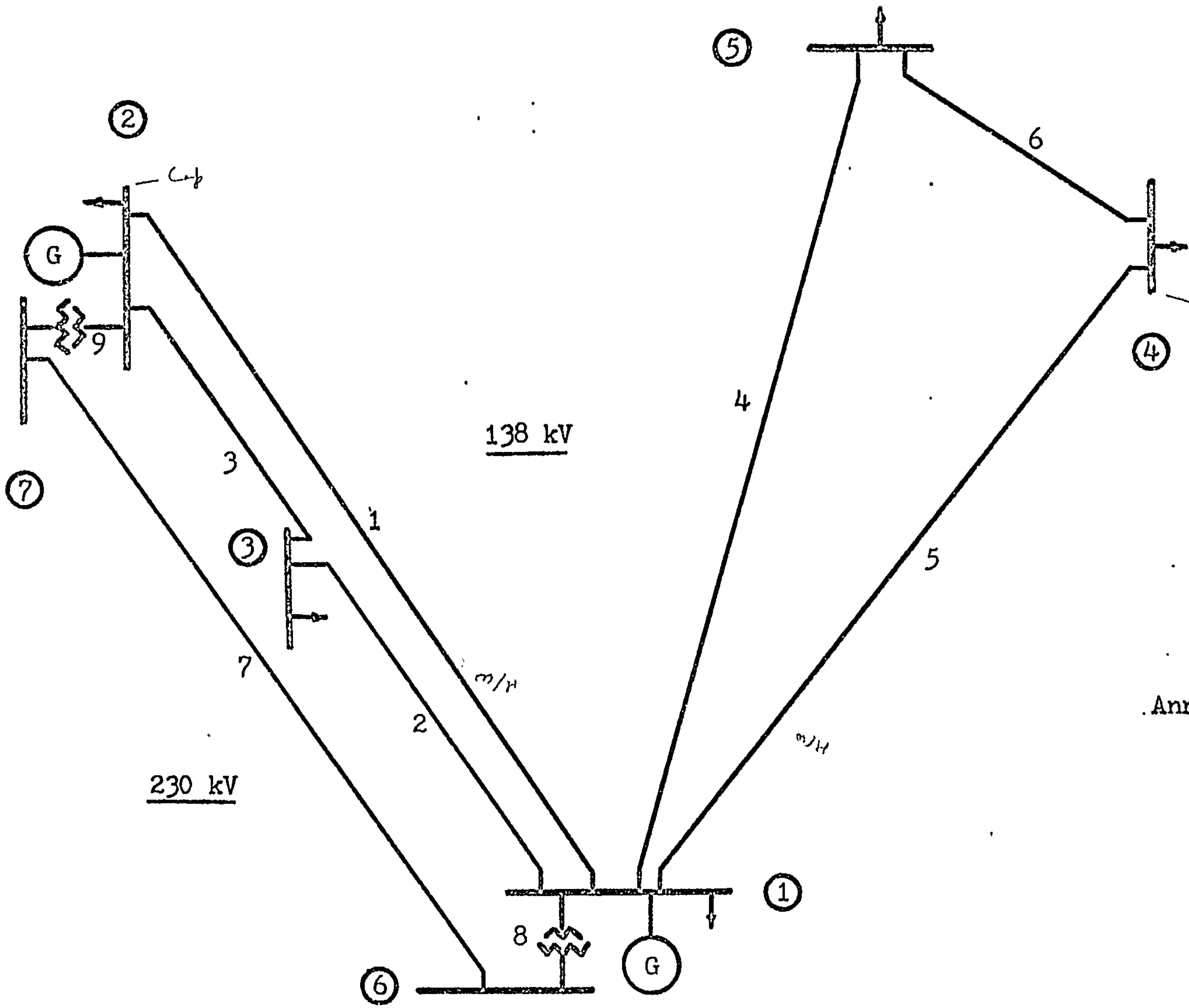
Computing the annual cost of transmission improvements utilizing these data is relatively straight forward. For simplicity, the lines and transformers are assumed to have one breaker at each terminal. In practice the design of the terminal equipment may be considerably influenced by the required flexibility for its operation and maintenance. The breakers and transformers required are shown in Figures 4.5, 4.6, 4.7, 4.8 and 4.10 for various transmission improvements. The cost of line is based on whether the line is built on an existing tower line or a new tower line. The costs of additions or conversion by the input data in any planning year are also evaluated and contribute to the annual cost. The present worth of each years expansion cost is computed using Equation 4.16. The sum of the present worths for the period of study is the total present worth to be used in comparing alternate proposals.

5. RESULTS OF PLANNING STUDIES

5.1 The Southern Saskatchewan System

The southern portion of the Saskatchewan system was simplified and studied to illustrate the transmission planning technique discussed in Chapter 4. The load growth and the generation expansion patterns considered for a period of 15 years are hypothetical and are not taken from the actual data. The network is shown in Figure 5.1. The system load and the three assumed generation expansion patterns are shown in Appendix 8.4. In the third pattern, a neighbouring system with excess generation in the north and a deficit in the south was assumed to take 50% of the future generation at Bus 1 into its own network and feed an equal amount back at Bus 5. Bus 5 was therefore considered as a completely reliable generating bus. The generating units were assumed to be rated at 0.9 power factor and therefore the increase in MVAR capability is equal to fifty percent of the MW capacity for the generation added. The minimum acceptable voltage was assumed to be 0.95 p.u. The reliability level was evaluated assuming complete generating capacity reliability and the risk level in terms of the probability of failure was used in the transmission planning. The forced outage data, the types of lines and transformers considered in planning, the right-of-way data, the terminal priority buses and the cost data are shown in Appendix 8.4. Economic dispatch generation was not considered and maximum plant output was assumed at Bus 2. Bus 1 was taken as the swing bus. The following planning studies were performed and the results are shown in Tables 5.1(a) to 5.1(g).

- Low voltage and overload criteria under normal operating



Bus	Initial Load MW	Initial Load MVAR
1	60	20
2	180	70
3	45	15
4	80	5
5	40	10
Total:	405	120

Annual Load Growth: 10%

Figure 5.1 The Southern Saskatchewan System conditions, for generation expansion patterns I, II and III shown in Tables 5.1(a), (b) and (c).

- Reliability criterion with three different acceptable risk levels, shown in Tables 5.1(d), (e) and (f) for generation expansion pattern I.

- Adequacy for single contingency outages for generation expansion Pattern I, shown in Table 5.1(g).

The transmission additions through the period of study for the above criteria are shown in Figures 5.2(a) to 5.2(g). Table 5.2 shows the present worth of the plans, based on annual charges 'to eternity'. The results show that a transmission network planned only in regard to satisfying the bus voltages and the line loadings is not adequate under forced outages. As expected the cost of transmission improvements increase as a higher reliability level is demanded. Using this approach it is possible to determine the increase in required investment to maintain or to improve the level of reliability in any portion of the system. Planning based on adequacy for single contingency outages can be considerably more expensive especially when lower reliability levels can be tolerated at some points in the system. The present worth associated with plans for different generation expansion patterns combined with the estimates of production costs provide an analytical basis to choose the desirable generation expansion pattern.

TABLE 5.1

The Transmission Planning in the Southern Saskatchewan System

(a) Normal Operating Conditions

Generation Expansion Pattern I

Year	Transmission Improvement	Condition to be Alleviated
1	-	-
2	10 MVAR Capacitance at Bus 5	Low voltage on Bus 5
3	10 MVAR Capacitance at Bus 5	Low voltage on Bus 5
	Line 10 between Buses 1 and 4	Low voltage on Bus 4
4	-	-
5	-	-
6	-	-
7	Line 11 between Buses 2 and 5	Low voltage on Bus 5
8	-	-
9	-	-
10	Line 12 between Buses 1 and 4	Low voltage on Bus 4
11	-	-
12	-	-
13	Line 13 between Buses 2 and 5	Low voltage on Bus 5
	Line 14 between Buses 2 and 3	Low voltage on Bus 3
14	Line 15 between Buses 1 and 4	Low voltage on Bus 4
15	-	-

TABLE 5.1(b)

Normal Operating Conditions

Generation Expansion Pattern II

Year	Transmission Improvement	Condition to be Alleviated
1	-	-
2	10 MVAR Capacitance at Bus 5	Low voltage on Bus 5
3	10 MVAR Capacitance at Bus 5	Low voltage on Bus 5
	Line 10 between Buses 1 and 4	Low voltage on Bus 4
4	-	-
5	-	-
6	-	-
7	Line 11 between Buses 2 and 5	Low voltage on Bus 5
	Line 12 between Buses 1 and 3	Low voltage on Bus 3
8	Line 13 between Buses 4 and 5	Low voltage on Bus 5
	Line 14 between Buses 2 and 5	Low voltage on Bus 5
	Line 1 converted to H.V.	Low voltage on Bus 2
	Transformer 15 between Buses 2 and 7	Overload on Transformer 9
	Transformer 16 between Buses 1 and 6	Overload on Transformer 8
9	Line 17 between Buses 1 and 4	Low voltage on Bus 4
10	Line 18 between Buses 6 and 7	Low voltage on Bus 7

(Table cont'd.) Normal Operating Conditions

Generation Expansion Pattern II

Year	Transmission Improvement	Condition to be Alleviated
11	Transformer 19 between Buses 2 and 7	Overload on Transformer 9
12	H.V. Bus formed at Bus 5 building Transformer 20 and Line 11 converted to H.V.	Low voltage on Bus 5
	Line 21 between Buses 6 and 7	Low voltage on Bus 7
13	Line 22 between Buses 1 and 4	Low voltage on Bus 4
14	Line 14 converted to H.V.	Low voltage on Bus 2
	Line 23 between Buses 2 and 3	Low voltage on Bus 3
	H.V. Bus formed at Bus 3 building Transformer 24 and Line 12 converted to H.V.	Low voltage on Bus 3
	Line 25 between Buses 6 and 7	Low voltage on Bus 7
	Transformer 26 between Buses 1 and 6	Overload on Transformer 8
15	Transformer 27 between Buses 2 and 7	Low voltage on Bus 2
	Line 28 between Buses 6 and 7	Low voltage on Bus 7
	Transformer 29 between Buses 1 and 6	Overload on Transformer 8

TABLE 5.1(c)

Normal Operating Conditions

Generation Expansion Pattern III

Year	Transmission Improvement	Condition to be Alleviated
1 to 6	-	-
7	Line 10 between Buses 1 and 3	Low voltage on Bus 3
8	Line 1 converted to H.V.	Low voltage on Bus 2
	Transformer 11 between Buses 2 and 7	Overload on Transformer 9
	Transformer 12 between Buses 1 and 6	Overload on Transformer 8
9	-	-
10	Line 13 between Buses 6 and 7	Low voltage on Bus 7
	Line 14 between Buses 4 and 5	Low voltage on Bus 4
11	-	-
12	Line 15 between Buses 6 and 7	Low voltage on Bus 2
	Transformer 16 between Buses 2 and 7	Overload on Transformer 9
	Transformer 17 between Buses 1 and 6	Overload on Transformer 8
13	-	-
14	Line 18 between Buses 2 and 3	Low voltage on Bus 3
	H.V. Bus formed at Bus 3 building Transformer 19 and Line 2 converted to H.V.	Low voltage on Bus 3

(Table cont'd.) Normal Operating Conditions

Generation Expansion Pattern III

Year	Transmission Improvement	Condition to be Alleviated
	Transformer 20 between Buses 1 and 6	Overload on Transformer 8
15	Line 21 between Buses 1 and 4	Low voltage on Bus 4
	Line 22 between Buses 1 and 4	Low voltage on Bus 4

TABLE 5.1(d)

Generation Expansion Pattern I

Reliability Criterion: Maximum Acceptable Risk of Failure Probability at Buses 1 and 2: 0.001 and at Buses 3, 4 and 5: 0.005

Year	Transmission Improvement	Condition to be Alleviated	Failure Probability at Bus 1	Bus 2	Bus 3	Bus 4	Bus 5
1	-	-	0.000000	0.000000	0.000000	0.002162	0.002073
2	10 MVAR Capacitance at Bus 5	Low voltage on Bus 5	0.000000	0.000000	0.000000	0.002073	0.002014
3	10 MVAR Capacitance at Bus 5	Low voltage on Bus 5					
	Line 10 between Buses 1 and 4	Low voltage on Bus 4	0.000000	0.000000	0.000000	0.000000	0.000000
4	-	-	0.000000	0.000000	0.000000	0.000000	0.000000
5	-	-	0.000000	0.000000	0.000000	0.000296	0.000491
6	-	-	0.000000	0.000000	0.000078	0.001083	0.001533
7	Line 11 between Buses 2 and 5	Low voltage on Bus 5	0.000000	0.000000	0.000152	0.000148	0.000000
8	-	-	0.000000	0.000000	0.000457	0.000427	0.000131
9	-	-	0.000000	0.000000	0.000457	0.001534	0.000883
10	Line 12 between Buses 1 and 4	Low voltage on Bus 4	0.000000	0.000000	0.000761	0.000000	0.000131
11	-	-	0.000000	0.000000	0.000761	0.000548	0.000253
12	-	-	0.000000	0.000000	0.001838	0.001577	0.001004
13	Line 13 between Buses 2 and 5	Low voltage on Bus 5					
	Line 14 between Buses 2 and 3	Low voltage on Bus 3	0.000000	0.000000	0.000074	0.001254	0.000109
14	Line 15 between Buses 1 and 4	Low voltage on Bus 4	0.000000	0.000000	0.000226	0.000000	0.000000
15	-	-	0.000000	0.000000	0.000375	0.000525	0.000240

TABLE 5.1(e)

Generation Expansion Pattern I

Reliability Criterion: Maximum Acceptable Risk of Failure Probability at Buses 1 and 2: 0.0001 and at Buses 3, 4 and 5: 0.001

Year	Transmission Improvement	Condition to be Alleviated	Failure Probability at Bus 1	Bus 2	Bus 3	Bus 4	Bus 5
1	-	-	0.000000	0.000000	0.000000	0.002162	0.002073
	Line 10 between Buses 1 and 4	High risk on Bus 4	0.000000	0.000000	0.000000	0.000000	0.000255
2	-	-	0.000000	0.000000	0.000000	0.000000	0.000255
3	-	-	0.000000	0.000000	0.000000	0.000296	0.001060
	Line 11 between Buses 2 and 5	High risk on Bus 5	0.000000	0.000000	0.000000	0.000000	0.000000
4	-	-	0.000000	0.000000	0.000000	0.000000	0.000000
5	-	-	0.000000	0.000000	0.000000	0.000000	0.000000
6	-	-	0.000000	0.000000	0.000078	0.000000	0.000000
7	-	-	0.000000	0.000000	0.000152	0.000148	0.000000
8	-	-	0.000000	0.000000	0.000457	0.000427	0.000131
9	-	-	0.000000	0.000000	0.000457	0.001534	0.000883
	Line 12 between Buses 1 and 4	High risk on Bus 4	0.000000	0.000000	0.000457	0.000000	0.000000
10	-	-	0.000000	0.000000	0.000761	0.000000	0.000131
11	-	-	0.000000	0.000000	0.000761	0.000548	0.000253
12	-	-	0.000000	0.000000	0.001838	0.001577	0.001004
	Line 13 between Buses 2 and 3	High risk on Bus 3	0.000000	0.000000	0.000000	0.001576	0.001004
	Line 14 between Buses 1 and 4	High risk on Bus 4	0.000000	0.000000	0.000000	0.000000	0.000131
13	-	-	0.000000	0.000000	0.000074	0.000109	0.000755
14	Line 15 between Buses 2 and 5	Low voltage on Bus 5	0.000000	0.000000	0.000226	0.000000	0.000000
15	-	-	0.000000	0.000000	0.000375	0.000525	0.000240

TABLE 5.1(f)

Generation Expansion Pattern I

Reliability Criterion: Maximum Acceptable Risk of Failure Probability at all buses: 0.0001

Year	Transmission Improvement	Condition to be Alleviated	Failure Probability at Bus 1	Bus 2	Bus 3	Bus 4	Bus 5
1	-	-	0.000000	0.000000	0.000000	0.002162	0.002073
	Line 10 between Buses 1 and 4	High risk on Bus 4	0.000000	0.000000	0.000000	0.000000	0.000255
	Line 11 between Buses 4 and 5	High risk on Bus 5	0.000000	0.000000	0.000000	0.000000	0.000000
2	-	-	0.000000	0.000000	0.000000	0.000000	0.000000
3	-	-	0.000000	0.000000	0.000000	0.000000	0.000000
4	-	-	0.000000	0.000000	0.000000	0.000000	0.000000
5	-	-	0.000000	0.000000	0.000000	0.000296	0.000148
	Line 12 between Buses 1 and 4	High risk on Bus 4	0.000000	0.000000	0.000000	0.000000	0.000000
6	-	-	0.000000	0.000000	0.000078	0.000000	0.000000
7	-	-	0.000000	0.000000	0.000152	0.000000	0.000000
	Line 13 between Buses 2 and 3	High risk on Bus 3	0.000000	0.000000	0.000000	0.000000	0.000000
8	-	-	0.000000	0.000000	0.000000	0.000000	0.000000
9	-	-	0.000000	0.000000	0.000000	0.000612	0.000612
	Line 14 between Buses 1 and 4	High risk on Bus 4	0.000000	0.000000	0.000000	0.000000	0.000000
10	-	-	0.000000	0.000000	0.000000	0.000000	0.000000
11	-	-	0.000000	0.000000	0.000000	0.000109	0.000780
	Line 15 between Buses 2 and 5	High risk on Bus 5	0.000000	0.000000	0.000000	0.000000	0.000000

(Table cont'd.) Generation Expansion Pattern I

Reliability Criterion: Maximum Acceptable Risk of Failure Probability at all buses: 0.0001

Year	Transmission Improvement	Condition to be Alleviated	Failure Probability at Bus 1	Bus 2	Bus 3	Bus 4	Bus 5
12	-	-	0.000000	0.000000	0.000000	0.000000	0.000000
13	-	-	0.000000	0.000000	0.000074	0.000000	0.000131
	Line 16 between Buses 2 and 5	High risk on Bus 5	0.000000	0.000000	0.000074	0.000000	0.000000
14	-	-	0.000000	0.000000	0.000226	0.000000	0.000000
	Line 17 between Buses 1 and 3	High risk on Bus 3	0.000000	0.000000	0.000000	0.000000	0.000000
15	-	-	0.000000	0.000000	0.000000	0.000109	0.000109
	H.V. Bus formed at Bus 4 building Transformer 18 and Line 5 converted to H.V.	High risk on Bus 4	0.000000	0.000000	0.000000	0.000000	0.000000

TABLE 5.1(g)

Single Contingency Outage Criterion

Generation Expansion Pattern I

Year	Transmission Improvement	Line/Transformer Removed	Condition to be Alleviated
1	Line 10 between Buses 1 and 4	5	Low voltage on Bus 4
	10 MVAR Capacitance on Bus 5	4	Low voltage on Bus 5
2	-	-	-
3	10 MVAR Capcitance on Bus 5	4	Low voltage on Bus 5
	Line 11 between Buses 1 and 4	10	Low voltage on Bus 4
4	-	-	-
5	Line 12 between Buses 2 and 3	2	Low voltage on Bus 3
	Line 13 between Buses 4 and 5	6	Low voltage on Bus 5
6	-	-	-
7	-	-	-
8	Line 14 between Buses 2 and 5	11	Low voltage on Bus 5
9	-	-	-
10	Line 15 between Buses 1 and 4	11	Low voltage on Bus 4
11	-	-	-
12	Line 16 between Buses 2 and 5	14	Low voltage on Bus 5

(Table cont'd.) Single Contingency Outage Criterion

Generation Expansion Pattern I

Year	Transmission Improvement	Line/Transformer Removed	Condition to be Alleviated
13	Line 17 between Buses 1 and 3	3	Low voltage on Bus 3
14	-	-	-
15	H.V. Bus formed at Bus 4 building Transformer 18 and Line 5 converted to H.V.	10	Low voltage on Bus 4
	Transformer 19 between Buses 4 and 8	18	Low voltage on Bus 4
	Line 10 converted to H.V.	5	Low voltage on Bus 4
	Transformer 20 between Buses 1 and 6	11	Overload on Transformer 8

Figure 5.2(a)-(g) Transmission Expansion of the Southern Saskatchewan System for Various Criteria

Normal Operating Conditions in (a),(b) and (c)

(a) Generation Expansion Pattern I
(b) Generation Expansion Pattern II
(c) Generation Expansion Pattern III

Reliability Criterion in (d),(e) and (f) with a Maximum Acceptable Risk Level in Terms of Probability of Failure at:

(d) Buses 1,2: 0.001; Buses 3,4,5: 0.005
(e) Buses 1,2: 0.0001; Buses 3,4,5: 0.001
(f) All Buses: 0.0001

(g) Single Contingency Outage Criterion

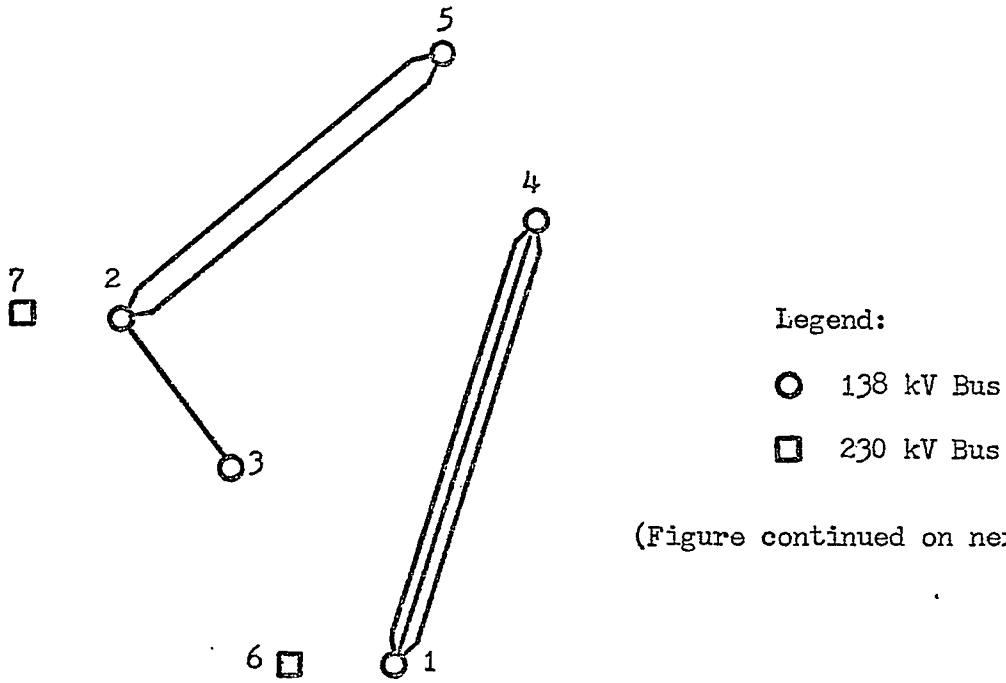


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Figure 5.2(a),(d) and (e)

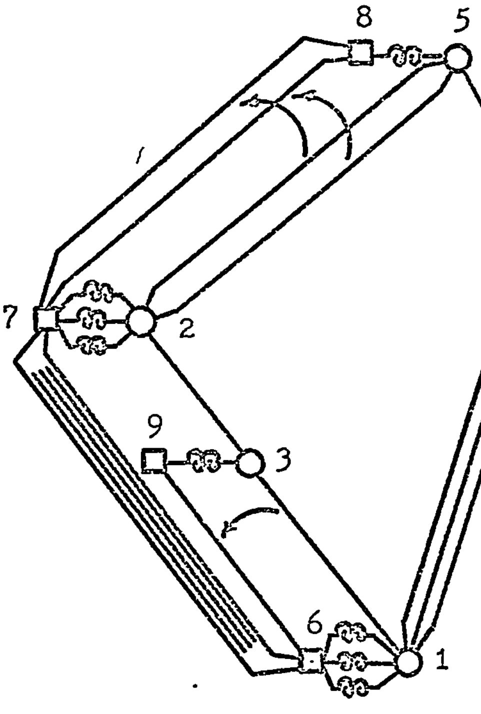

Figure 5.2(b)

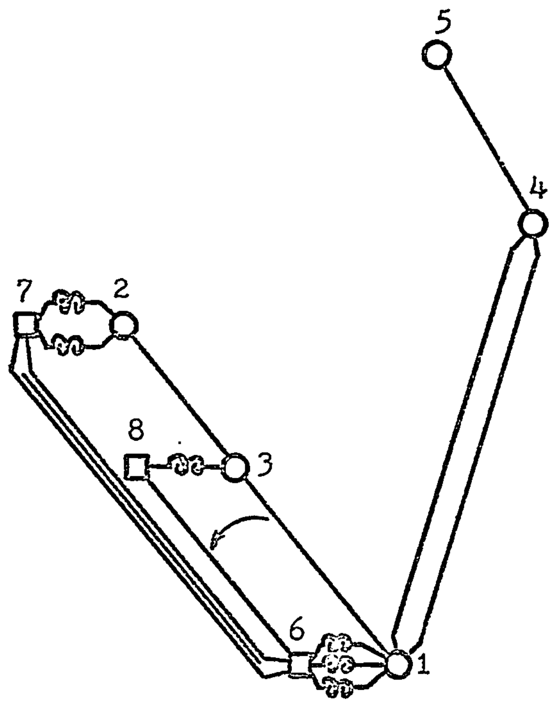

Figure 5.2(c)

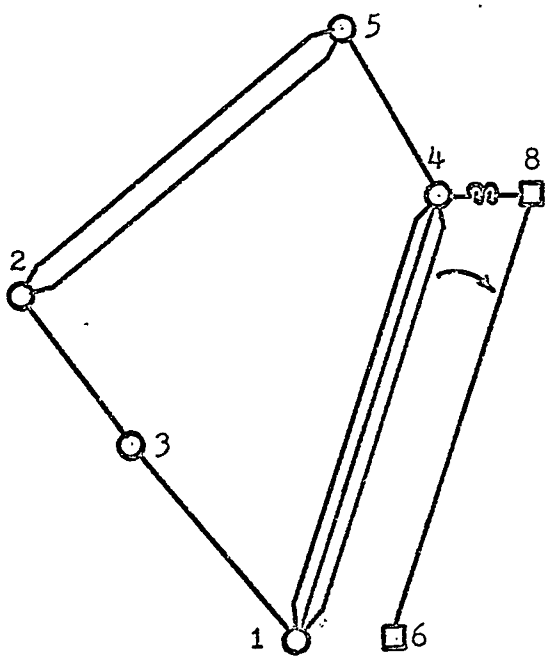

Figure 5.2(f)

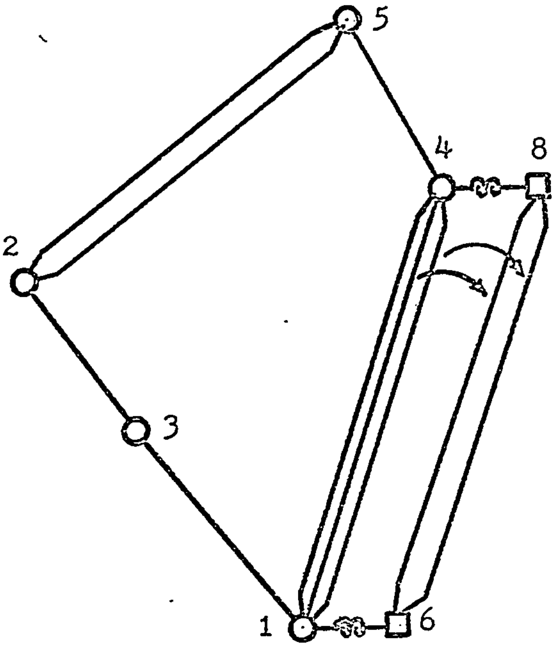

Figure 5.2(g)

TABLE 5.2

The Present Worth of Transmission Requirements

in the Southern Saskatchewan System for Various Criteria

Case	Planning Criteria	Present Worth[1]	Increase Over Case I(a)
I	Normal operating conditions		
	(a) Generation expansion pattern I	9954.0	-
	(b) Generation expansion pattern II	23160.0	13206.0
	(c) Generation expansion pattern III	13987.0	4033.0
II	Reliability criterion and Generation expansion pattern I		
	(a) Max. risk at Buses 1 and 2: 0.001 and at Buses 3, 4 and 5: 0.005	9954.0	0.0
	(b) Max. risk at Buses 1 and 2: 0.0001 and at Buses 3, 4 and 5: 0.001	11132.0	1178.0
	(c) Max. risk at all buses: 0.0001	12804.0	2850.0
III	Single contingency outage criterion and Generation expansion pattern I	14439.0	4485.0

1 Computed in thousands of dollars using Equation 4.16 with $r = 0.11$, $i = 0.075$ and $f = 1.02$. Double circuit steel tower lines are assumed.

5.2 The Major Network of the Saskatchewan System

The major network of the Saskatchewan Power Corporation has been studied to illustrate the transmission planning technique in a relatively large system. The network as shown in Figure 3.4 is represented by two voltage levels, 230 kV and 138 kV. The data for the 10 year planning study are shown in Appendix 8.5. The forced outage data and the Type Data are the same as that used in the previous study and are shown in Appendix 8.4. The forced outage rates of the 100 MW and the 140 MW thermal units added were taken as 0.04. A value of 0.016 was used for the 50 MW units. Only one generation expansion pattern was considered. The distribution of the forecast system load at each bus was assumed to be the same as in the initial year. With 230 kV lines between Buses 1-14 and 19-20, the reliability evaluation for one system load condition considering three load probability steps and single outages took more than 20 minutes of computer time. It was decided to simplify the network shown in Figure 3.4 in order to save computer solution time. The 230 kV lines were connected through the transformers directly to the 138 kV buses without forming separate high voltage buses. The forced outage parameters of the line were assumed to be the same for the series arrangement, neglecting the transformer failure rates. This results in negligible error in the calculated risk levels if the transformers at the stations are fully redundant. All lines other than 138 kV added in the planning period were represented in the same manner without forming separate higher voltage buses. 230 kV lines between Buses 3-4 and 3-11 and 138 kV lines at all other locations are considered in the planning. 345 kV lines are considered as possible extra-high voltage reinforcement.

Economic generation schedules were not considered. Studies indicated that due to relatively low fuel costs at Bus 3 and less expensive hydro power at Buses 1 and 6 that these plants would be fully loaded for system peak load operation. The generation outputs at Buses 4 and 5 were at the maximum value and Bus 2 was used as the swing bus. The transmission adequacy was not tested with selected generation schedules to consider the generating unit outages at points where generating plants are directly connected to loads.

The required transmission improvements are shown in Table 5.3. Table 5.3(a) shows the expansion if the network is required to satisfy only the bus voltages and the line loadings under peak load conditions without considering forced outages. The minimum acceptable voltage was assumed to be 0.96 per unit at generating buses and 0.95 per unit at other buses. The expansion pattern shown in Table 5.3(b) includes the utilization of a reliability criterion. The maximum acceptable risk levels were assumed to be 0.0001 probability of failure for loads at generating buses and 0.001 for all other loads.

In the study using the reliability criterion, the high risk at Bus 5 in 1973 is due mainly to the contribution at the low load level as most of the generation is supplied by Bus 3 with other plant outputs being at the minimum. This is due to low fuel costs at Bus 3 and water limitations at the hydro plants at Bus 1 and Bus 6. The transmission capability is inadequate between Buses 3-4 and 4-5 under these operating conditions. This condition was improved by adding 345 kV lines between Buses 2-4 and 3-4 by the input data.

The risk level at Bus 7 is 0.000850 in the period 1969-73, 0.000034 in 1974 and negligible in 1975-78. The risk level at Bus 8 is 0.001300 in 1969-76, 0.00000004 in 1977 and negligible in 1978. These buses