THE UNIVERSITY OF CALGARY

EFFECTS OF INTERCONNECTING THE ELECTRIC SYSTEMS OF BRITISH COLUMBIA, ALBERTA, AND SASKATCHEWAN ON THE RELIABILITY OF SUPPLY IN ALBERTA

by

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A THESIS

SUBMITTED TO THE FACULTY OF GRADUATE STUDIES

IN PARTIAL FULFILMENT OF THE REQUIREMENTS

FOR THE DEGREE OF MASTER OF ENGINEERING

DEPARTAMENT OF ELECTRICAL ENGINEERING

CALGARY, ALBERTA

APRIL, 1987

ISBN Ø-315-35958-7

THE UNIVERSITY OF CALGARY

FACULTY OF GRADUATE STUDIES

The undersigned certify that they have read, and recommended to the Faculty of Graduate Studies for acceptance, a thesis entitled, *"Effects of Interconnecting the Electric Systems of British Columbia, Alberta, and Saskatchewan on the Reliability of Supply in Alberta"* submitted by Patricio E. Wickel in partial fulfillment of the requirements for the degree of Master of Engineering.

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ABSTRACT

The reliability of supply in a power system is studied when the system operates isolated as well as interconnected to neighboring power systems. When isolated, the reliability is evaluated combining the load characteristics with the capacity outage probability table, which represents all possible outage events in the generating capacity. When the system is interconected with neighboring power systems, the "equivalent assisting unit method" is used to represent the assisting systems as assisting generating units that are incorporated into the generating capacity of the system of interest.

This approach to reliability is implemented in a computer model that considers the effects of generating unit size, forced outage rates , maintenance schedules, energy limitations on hydroelectric plants, tie-line capacities, tie-line outage rates, number of tie lines, and firm capacity contracts.

The reliability of supply in Alberta, when interconnections with British Columbia and Saskatchewan are considered, varies considerably depending on the operating conditions imposed on the power systems. However, under the most likely scenario, the reliability of supply in Alberta will be greatly increased by the potential capacity assistance, available from the neighboring provinces. Alberta might delay the construction of new generating facilities by 2 - 4 years.

ACKNOWLEDGEMENTS

I hereby express my gratitude to Professor G. J. Berg, my Supervisor, for his guidance throughout this work.

Thanks are due to the people in The Energy Resources Conservation Board of Alberta who sponsored this work.

TO PATRICIA

Although the Energy Resources Conservation Board of Alberta sponsored this work, the views and conclusions expressed by the author do not reflect the opinion of this organization.

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INTRODUCTION

The objective of this project is to study the reliability of electric energy supply in Alberta if it were interconnected with British Columbia and Saskatchewan, and to examine effects of such interconnections on the future development of the Alberta electric system.

The study is limited to the static capacity requirement in the province, which can be considered to be installed capacity that must be planned and constructed in advance of system requirements. Installed capacity must be sufficient to meet anticipated demand and provide reserve for the overhaul of generating equipment, outages that are not planned or scheduled, and some load growth requirements in excess of forecasts.

Probability methods rather than deterministic methods are applied, to the static capacity problem, because they provide an analytical basis for capacity planning which can be extended to cover capacity of interconnections, effects of generating unit size and design, effects of maintenance schedules, and other system parameters.

The Loss of Load Expectation (LOLE) and the Loss of Energy Expectation (LOEE) are the indices chosen to "measure" the reliability of electric energy supply. At the present time the LOLE index is the most widely used probabilistic measure for assessing the adequacy of a given generation configuration. The LOEE, although not as widely used as the LOLE, is expected to gain popularity as power systems become more energy constrained. References [1] and [2] present more information regarding the use of reliability indices in Alberta and throughout Canada.

At the present time, Alberta is interconnected with B.C. through a 500 kV transmission facility. This tieline is able to transmit at least 800 MW of electric power.

An application for approval of a transmission line interconnecting Alberta and Saskatchewan is presently being prepared. This tieline may be a 240-kV facility with a capability of 100 - 150 MW.

Recent studies, (references [3], [4]), addressing the static capacity requirements of this province, assumed the capacity assistance from B.C. to be fixed at 300 MW throughout the entire planning period of more than 30 years. Moreover, such capacity assistance was assumed to be fully reliable at the sending end of the tieline. The interconnection with Sask. was not addressed in those studies.

This study considers the effect of both Alta.-B.C. and Alta.- Sask. interconnections on the reliability of supply as well as on the static capacity requirements in Alberta. The individual interconnections considered are not limited to a fixed capacity. Instead, variable capacity assistance, which is dependent on the available reserve capacity in the assisting system(s), is used throughout the study period. Also, the capacity assistance is not assumed fully reliable but subject to scheduled and random outages of the assisting system(s).

Chapter 2 of this report presents the basic theory used in this study in order to evaluate the reliability of power systems. It begins by considering an isolated power system, then extends the analysis to interconnected systems.

Chapter 3 describes the computer model developed to evaluate the reliability indices of interconnected systems using the theory outlined in Chapter 2. The model is made up of two separate computer programs. The first one treats each individual system as an isolated system. The second program interconnects the systems according to user-imposed constraints on transmission lines and capacity contracts.

In Chapter 4 the model discussed in Chapter 3 is used to investigate the reliability of supply and the static capacity requirements of Alberta under specific operating conditions. Selected results are presented and discussed.

Chapter 5 presents the conclusions of this study together with comments on the method used, and a summary of advantages and disadvantages of the computer model. The list of disadvantages represents a source of topics for further research and development of the computer model.

Chapter II

RELIABILITY OF POWER SYSTEMS

2.1 INTRODUCTION

A modern power system is complex, physically extensive and highly integrated. It serves the function of supplying customers with electric energy as economically and as reliably as possible. Modern society tends to expect the supply to be continuously available on demand, but this is not quite possible due to random failures which are generally outside the control of the power system operators.

The complexity of a modern power system makes it necessary to subdivide the system into appropiate subsystems that can be analyzed separately. Reliability studies are then conducted on each subsystem. Typical reliability studies are as follows.

- Reliability of the generating plants, in which each plant or each unit in the plant is analyzed separately.

- Reliability of the generating capacity, which is evaluated neglecting the transmission and distribution networks.

- Reliability of the transmission network, which is evaluated neglecting the generating sources.

- Composite generation/transmission reliability, in which the network is limited to the primary transmission only.

- Reliability of interconnected systems, in which only the generating capacity and the interconnecting transmission lines are considered.

- Reliability of substations and switching stations.

- Reliability of the protection systems.

This chapter focuses on the theory involved in determining the reliability of the generating capacity and interconnected systems. It specifically presents the theory needed to calculate the LOLE and LOEE of an isolated system as well as an interconnected system. These reliability indices are used in Alberta to determine the adequacy of different generation configurations.

2.2 ISOLATED SYSTEM

As stated earlier, the reliability of the generating capacity in an isolated system is conventionally evaluated neglecting the transmission and distribution networks. The system representation in this case is as shown in Fig. 2.1.

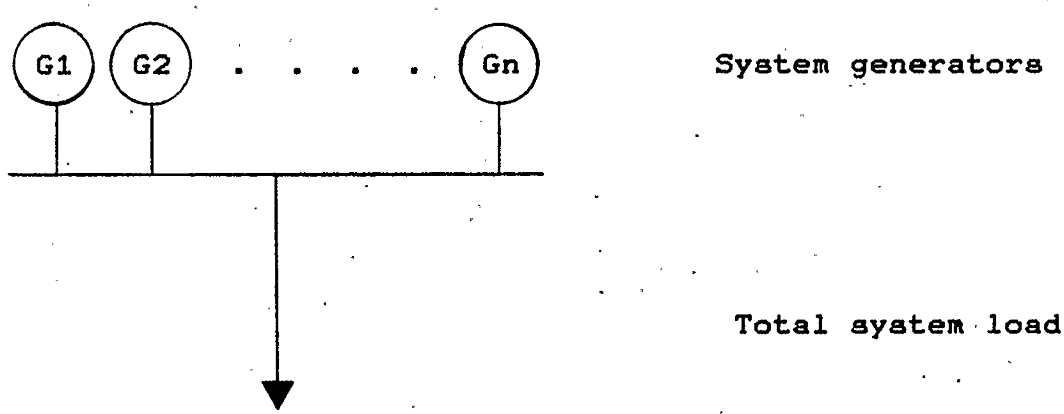


Fig. 2.1 Conventional system model

The approach presented in this section for evaluating the reliability indices of isolated systems is as follows.

The output capacity and the probability of a forced outage of the generators are combined to form a system capacity outage probability table. Then the reserve capacity, which depends on the installed capacity and on the system load, is combined with the system capacity outage probability table to determine reliability indices. The calculated indices in this case do not reflect generation deficiencies at any particular point within the network but measure the overall adequacy of the generation system. References [5] and [6] present evaluations and comparisons of different methods for calculating generating system reliability.

2.2.1 Generation system model

The basic generating unit parameter used in static capacity evaluation is the probability of finding the unit on forced outage. This probability represents the unavailability of the unit , and historically in power system applications it is known as the forced outage rate (FOR).

In Alberta, the FOR used for planning purposes is calculated based on the performance of the past five years and is updated each year to reflect any changing conditions of the units. Reference [3] presents the expression for the calculation of FOR. This is:

$$FOR = \frac{F.O.H. \times 100}{F.O.H. + S.H.} \% \qquad 2.1$$

where:

F.O.H.: Forced outage hours. The total time during which a unit is unable to supply energy to the system due to a forced outage.

S.H. : Service hours. The total time during which a unit is synchronized to the system.

The concept of FOR is associated with the modeling of a generating unit as a two-state unit which can be found "in service", i.e. supplying electric power to the system or "forced out", i.e. out of service for repairs, as shown in figure 2.2.

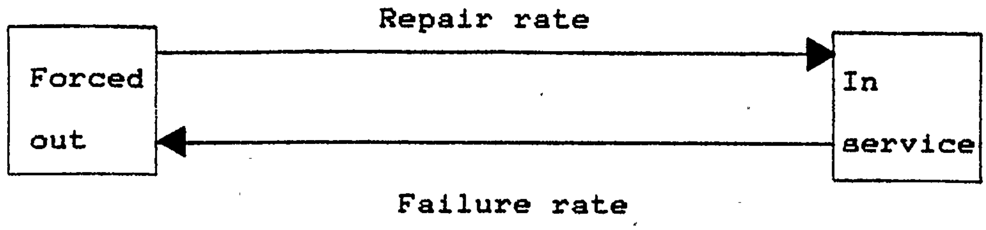


Fig. 2.2 Two-state representation of generating units

This model is very adequate for units with relatively long operating cycles, such as base load generating units which are either operating or forced out of service. Scheduled outages for maintenance purposes must be considered separately.

In the case of peaking or intermittent operating units, this model is less adequate because such units spend long periods of time out of service, mainly for economical or enviromental reasons, and they are brought back to service only for short periods of time, (e.g. during peaking hours or at times when it is enviromentally possible). Also, the most critical period in the operation of a unit is the start-up period, and in comparison with a base load unit, a peaking unit will have fewer operating hours but many more start-ups and shut-downs.

To overcome this problem, a method that considers the effect of intermittent operation and start-ups on the FOR of generating units is presented in reference [7]. The method represents the unit as a four-state unit which can be found "in service", "forced out in period of need", "forced out but not needed", and in "reserve shutdown". Reference [3] presents the expressions used by the utilities in Alberta for the calculation of the forced outage probability associated with the four-state model. These are as follows.

$$FOP = \frac{f(F.O.H.) \times 100}{f(F.O.H.) + S.H.} \% \qquad 2.2$$

where

FOP : Forced outage probability

$$f : \text{Demand factor} = \frac{1/r + 1/T}{1/D + 1/r + 1/T} \qquad 2.3$$

r : Average forced outage time

$$r = \frac{\text{F.O.H.}}{\text{Total. No. of forced outages}} \quad 2.4$$

D : Average in-service time per occasion of demand.

$$D = \frac{\text{S.H.}}{\text{S.R. x Total attempted starts}} \quad 2.5$$

T : Average reserve shutdown time between periods of need, exclusive of periods for maintenance or other planned unavailability

$$\text{S.R.} = \frac{\text{Total attempted starts - Total start failures}}{\text{Total attempted starts}} \quad 2.6$$

In summary, the generation system model used in static capacity reliability evaluation is made up of all the existing generating units connected to the network to supply the system load. Each generating unit is represented by its output capacity together with the probability of finding the unit on forced outage. This probability is normally referred to as the FOR and it can be computed based on historic data regarding the performance of the unit. Expression 2.1 is adequate for units with long operating cycles, while expressions 2.2 to 2.6 are more appropiate for units with short operating cycles.

2.2.2 Capacity outage probability table

After the individual unit FOR's are known, the capacity outage probability table is developed; as the name suggests, it is a simple array of capacity levels and their associated probability of existence. Basically, the development of the table requires the identification of all possible outage events (e.g., in a system of "n" units, this means "2 to the power n" events) and a determination of the probability of the respective outages occurring. Since the static capacity reliability evaluation is more concerned with system capacity outages than with particular unit outages, the probability of a given total amount of capacity being on outage has to be calculated. This is presented as a capacity outage cumulative probability table as described in the following example:

Example No. 1: Consider a small system comprised of only three units, whose characteristics are presented in Table 2.1.

Unit	Capacity "C" (MW)	FOR	1 - FOR
A	100	0.01	0.99
B	150	0.02	0.98
C	200	0.03	0.97

Table 2.1: Unit characteristics Example No. 1

The probability of all possible combinations of units being in or out are calculated as shown in Table 2.2. The cumulative column, which gives the probability of "x" MW or more on outage, is obtained by starting with the value at the bottom of the probability column and adding upwards.

Units on outage	"x" MW	Probability	Probability of "x" MW or more on outage. P(x)
None	0	(0.99)(0.98)(0.97)= 0.941094	1.000000
A	100	(0.01)(0.98)(0.97)= 0.009506	0.058906
B	150	(0.99)(0.02)(0.97)= 0.019206	0.049400
C	200	(0.99)(0.98)(0.03)= 0.029106	0.030194
A,B	250	(0.01)(0.02)(0.97)= 0.000194	0.001088
A,C	300	(0.01)(0.98)(0.03)= 0.000294	0.000894
B,C	350	(0.99)(0.02)(0.03)= 0.000594	0.000600
A,B,C	450	(0.01)(0.02)(0.03)= 0.000006	0.000006

Table 2.2: Capacity outage probability table of Example No. 1

The capacity outage probability table should be recalculated each time there are any changes in unit rating, FOR, unit retirements, or new unit additions. This is a significant requirement that should be considered in writing the computer programs. Accordingly, a better way of building the outage table is to use a recursive method, such as the method presented in reference [8].

The recursive method "adds" one unit at a time to build an outage table; the final outage table is obtained after all the existing units have been "added" to the table.

The cumulative probability of a particular capacity of "x" MW after a unit of capacity "c" MW and forced outage rate "FOR" is "added", is given by:

$$P(x) = (1 - FOR)*P(x)' + (FOR)*P(x-c)' \qquad 2.7$$

where $P(x)'$ and $P(x)$ denote the cumulative probabilities of the capacity outage state of "x" MW before and after the unit is added. The above expression is initiated by setting $P(x)' = 1.0$ for x < or = 0 and $P(x)'=0$ for x > 0.

<u>Example No.</u> <u>2</u>: Consider the power system of Example No. 1. The recursive method works as follows.

Addition of unit "A"

$P(0) = (1 - 0.01)(1.0) + (0.01)(1.0) = 1.0$

$P(100) = (1 - 0.01)(0) + (0.01)(1.0) = 0.01$

Addition of unit "B"

$$P(0) = (1 - 0.02)(1.0) + (0.02)(1.0) = 1.0$$

$$P(100) = (1 - 0.02)(0.01) + (0.02)(1.0) = 0.0298$$

$$P(150) = (1 - 0.02)(0) + (0.02)(1.0) = 0.02$$

$$P(200) = (1 - 0.02)(0) + (0.02)(0.01) = 0.0002$$

Addition of unit "C"

$$P(0) = (1- 0.03)(1.0) + (0.03)(1.0) = 1.0$$

$$P(100) = (1- 0.03)(0.0298) + (0.03)(1.0) = 0.058906$$

$$P(150) = (1- 0.03)(0.02) + (0.03)(1.0) = 0.0494$$

$$P(200) = (1- 0.03)(0.0002) + (0.03)(1.0) = 0.030194$$

$$P(250) = (1- 0.03)(0.0002) + (0.03)(0.0298) = 0.001088$$

$$P(300) = (1- 0.03)(0) + (0.03)(0.0298) = 0.000894$$

$$P(350) = (1- 0.03)(0) + (0.03)(0.02) = 0.0006$$

$$P(400) = (1- 0.03)(0) + (0.03)(0.0002) = 0.000006$$

This approach can also be used for a multi-state unit, i.e., a unit which can exist in one or more derated or partial output states as well as in the fully up or fully down states. Equation 2.7 can be modified as follows to include multi-state unit representations:

$$P(x) = \sum_{i=1}^{n} pi*P'(x-Ci) \qquad 2.8$$

where

n : number of unit states

Ci: capacity outage of state "i" for the unit being added

pi: probability of existence of the unit state "i"

Note: when n=2, Equation 2.8 reduces to Equation 2.7.

2.2.3 System load model

The load imposed on an electric power system changes every moment during the day, from day to day, from month to month, and from year to year. The changing nature of the load from one year to another can be taken into account by specifying the peak demand forecasted for each year of study. If seasonal changes of the load characteristics are to be considered, the year is sub-divided into a number of periods (typically months or weeks) and the peak demand forecasted in each period is specified.

Let us assume that for a given power system, the year is divided into periods of one month each, and that Figure

2.3(a) represents the chronological hourly load curve for one of these monthly periods. Curves such as the one in this figure, together with the relevant plant information, are very useful for determining the schedule of maintenance and energy production of each unit in the system when the period of interest covers a few months, or 1 to 2 years. For long range planning studies, as considered here, it is convenient to transform this chronological load curve into a load duration curve (LDC) to represent the characteristics of the load as illustrated in Figure 2.3(b).

As with the chronological hourly load curve, the area under the LDC measures the total energy requirements of the system. However, the chronological sequence of loads has been lost. In the LDC the abcissa represents the number of hours during which the system load equals or exceeds the associated amount of power on the ordinate. By normalizing the load and time variables, any point on the abcissa (Xi) becomes the fraction of time for which the load equals or exceeds the fraction of load represented by the associated point on the ordinate (Yi), as shown in Figure 2.3(c). The so-defined normalized LDC of the time periods, together with their corresponding peak demands and time lengths, constitute the system load

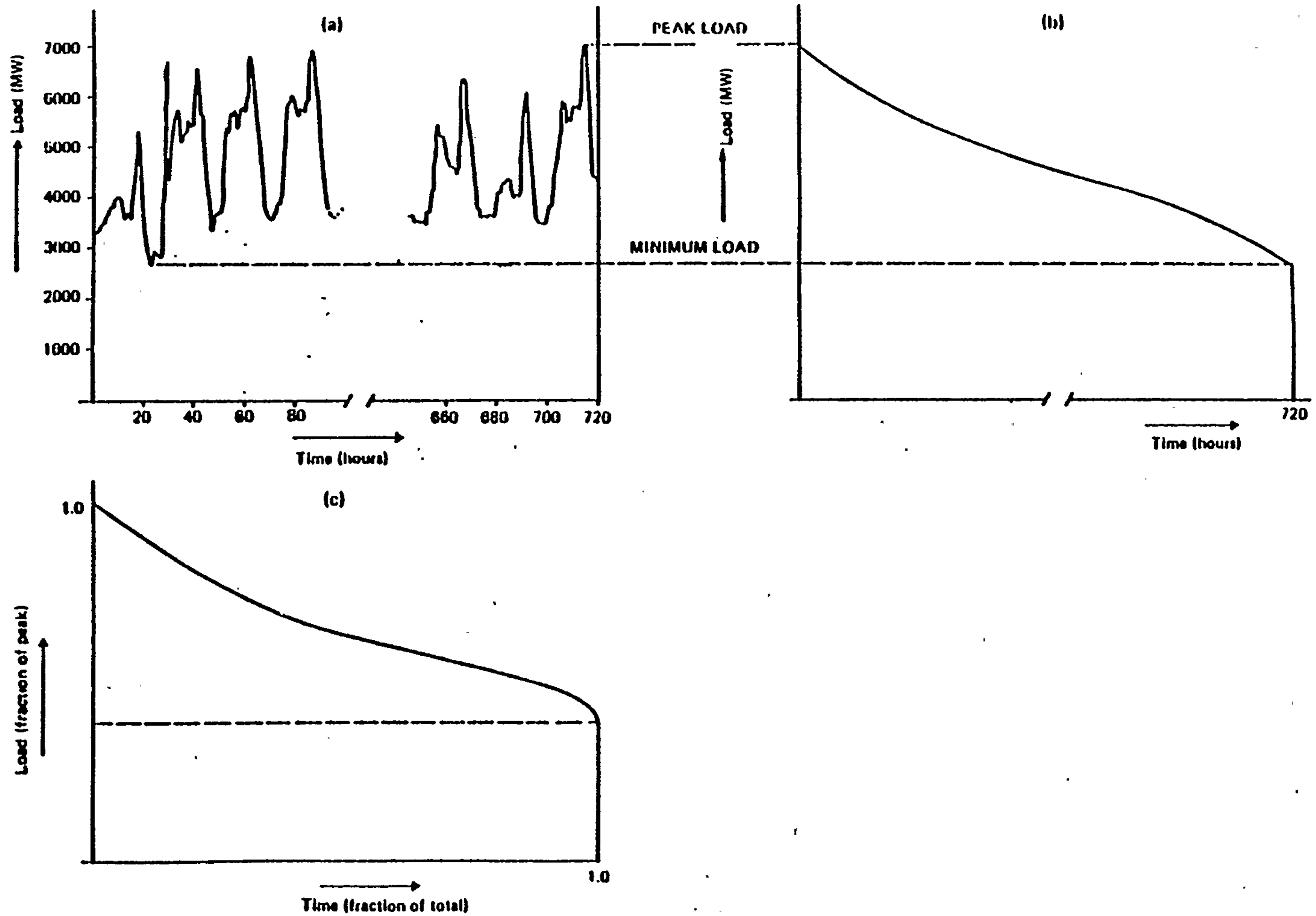


Figure 2.3: Representation of the load of a power system.
(a): Chronological hourly loads.
(b): Load Duration Curve.
(c): Normalized Load Duration Curve

model.

2.2.4 Loss of load expectation

The load duration curve is used in conjuction with the capacity outage probability table to obtain the expected number of hours in which the load will exeed the available capacity. As shown in Figure 2.4, the reserves are obtained by subtracting load from available capacity. On this basis, a deficiency in available capacity, i.e., a loss of load, occurs if the capacity on outage exeeds the reserves. The probability of this outage is read directly from the capacity outage cumulative probability table, and is the loss of load probability for one hour.

The sum of the loss of load probabilities in each hour in the period becomes the expected number of hours in which the load will exceed the available capacity in that period. The index in this case is designated as the loss of load expectation (LOLE) and it is measured in hours/period.

$$LOLE = \sum_{i=1}^{n} P(Ri) \quad \text{hrs/period} \tag{2.9}$$

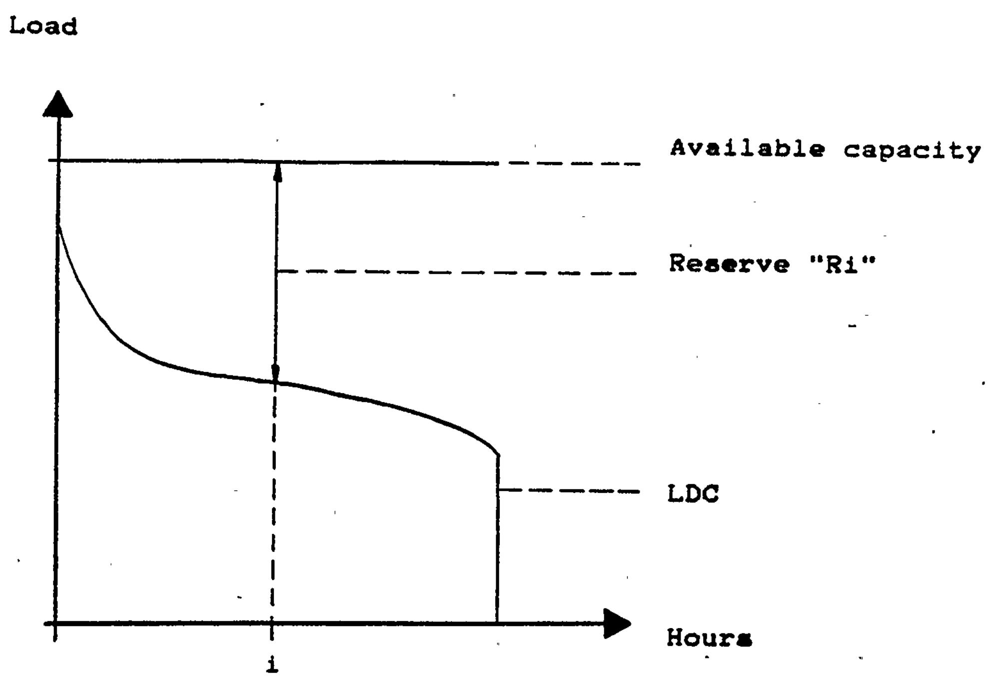


Figure 2.4: Reserve capacity at hour "i"

where

Ri : reserve at hour "i"

P(Ri) : probability of loss of load in hour "i". This value is obtained directly from the capacity outage cumulative probability table.

n : total number of hours in the period.

Reference [9] presents a more detailed explanation regarding this method for calculating the LOLE.

2.2.5 Loss of energy expectation

The area under the LDC represents the energy associated with the specified period and can be used to calculate expected energy not supplied due to insufficient installed capacity.

The probabilities of having varying amounts of capacity unavailable are combined with the LDC as shown in Figure 2.5. Any outage of generating capacity exceeding the reserve will result in a curtailment of energy supply. Let:

Oi = magnitude of the capacity on outage.

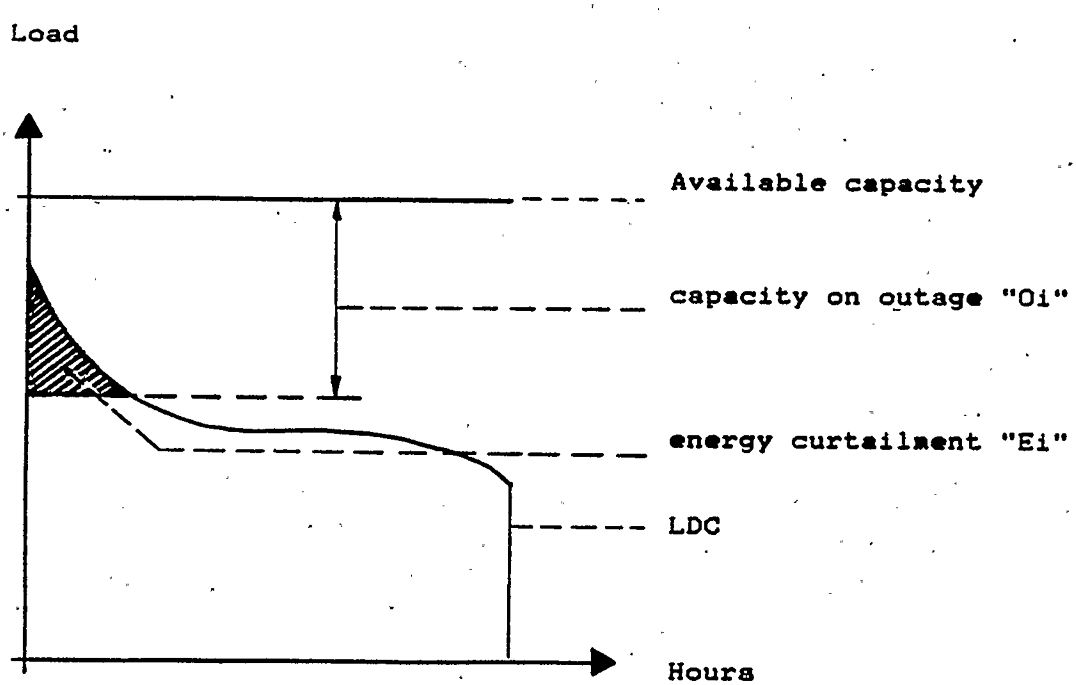


Figure 2.5: Energy curtailment due to capacity outage

$P(Oi)$ = probability of capacity outage equal to Oi. Value obtained from the outage capacity probability table.

Ei = energy curtailed by capacity outage equal to Oi.

This energy curtailment is shown as the shaded area in Figure 2.5. The probable energy curtailed is $Ei*P(Oi)$, and the sum of these products becomes the total expected energy curtailment or loss of energy expectation (LOEE) in the period represented by the LDC.

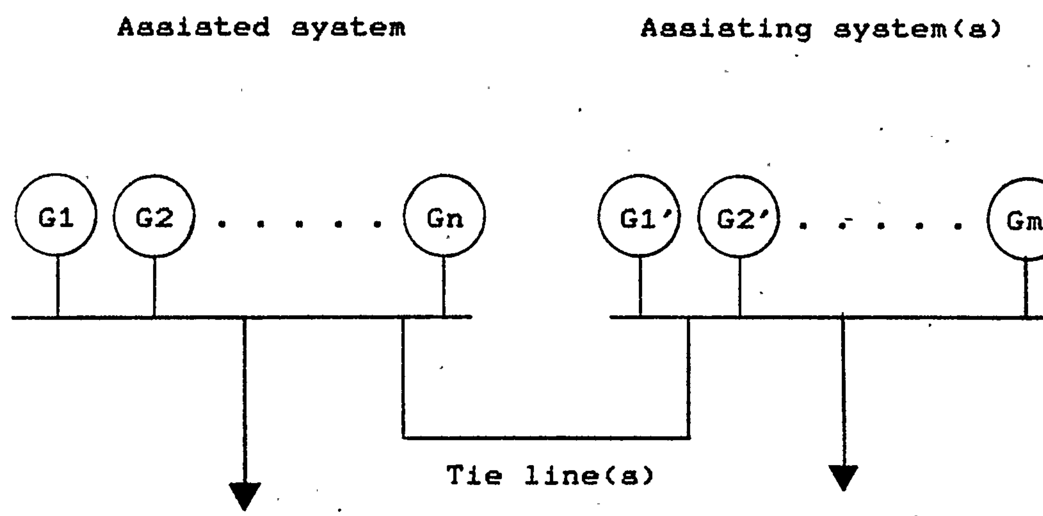
$$LOEE = \sum_{i=1}^{n} Ei*P(Oi) \qquad 2.10$$

where n is the total number of capacity levels in the outage table.

Reference [9] presents a more detailed explanation regarding this method for calculating the LOEE.

2.3 INTERCONNECTED SYSTEMS

The reliability of the generating capacity in a system which is interconnected with neighboring systems is conventionally evaluated neglecting the transmission and distribution networks, but including the interconnecting transmission lines. The system representation in this case is as shown in Fig. 2.6.



<u>Figure 2.6: Conventional representation of interconnected systems</u>

This section presents the "equivalent assisting unit" approach to reliability evaluation of interconnected systems, (reference [9]). The approach consists of representing the assisting systems as equivalent multi-state units that can be "added" to the assisted system. The assisted system can then be treated as if it were an isolated system, and its reliability evaluation can proceed as discussed in the preceding section.

The equivalent multi-state unit describes the ability of the assisting system's generating units to accommodate capacity deficiencies in the assisted system. It takes into consideration the effect of factors such as tie-line capacities, tie-line reliabilities, and number of tie lines. In this section, the equivalent assisting unit approach is also used to consider the effect of firm purchase capacity agreements on the reliability of the assisted system.

2.3.1 Equivalent assisting unit approach

Consider a power system, System No.1, interconnected to neighboring systems, Nos. 2,3,...,n as shown in Fig.2.7. Assume that System No.2, the assisting system, is supplying capacity assistance to System No.1, the assisted system, and that the tie line between systems No.1 and No.2 is a fully reliable transmission line of infinite capacity.

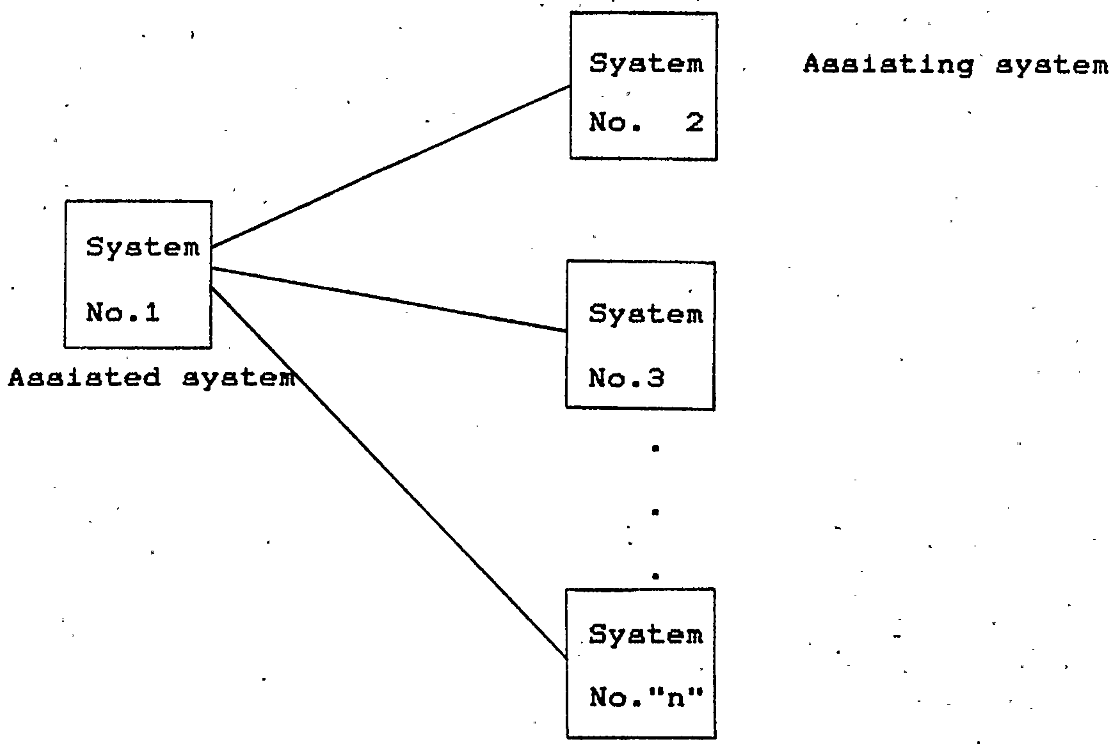


Figure 2.7: "n" interconnected systems

Also, suppose that the capacity outage probability table of System No.2 has been derived, and is of the form shown in Table 2.3.

State	Outage capacity	Probability
1	O1 (= O)	P(O1)
2	O2	P(O2)
.	.	.
.	.	.
.	.	.
j	Oj	P(Oj)
k	Ok	P(Ok)
.	.	.
.	.	.
.	.	.
n	On	P(On)

Table 2.3: Capacity outage probability table of System No. 2

Where Oi is the amount of capacity on outage and P(Oi) is the probability of occurrence of a capacity outage equal to Oi. (This value should not be confused with the cumulative probability which represents the probability of occurrence of a capacity outage equal or greater than Oi).

System No.2 has a reserve "R" which is the maximum assistance it can provide to System No.1.

The different levels of capacity assistance that System No.2 can provide to System No.1 are derived from its capacity outage probability table. If there were no capacity on outage in the assisting system, it could assist System No.1 with a capacity equal to its reserve "R". On the other hand, if the assisting system had an outage of capacity equal to or greater than its reserve, no capacity assistance would be possible.

Let us assume that the reserve "R" in the assisting system satisfies the condition:

$$O_j < R \leq O_k \text{ .}$$

Then, the capacity assistance probability table can be derived as shown in Table 2.4.

State	Capacity assistance	Probability
1	$A1 = R - O1 \ (= R)$	$P(O1)$
2	$A2 = R - O2$	$P(O2)$
.	.	.
.	.	.
.	.	.
j	$Aj = R - Oj$	$P(Oj)$
k	$Ak = 0.0$	$\sum_{i=k}^{n} P(Oi)$

Table 2.4: Capacity assistance probability table of System No.2

Where "Ai" is the level of capacity assistance that System No.2 can provide when it has an outage of capacity "Oi". The probability of a capacity assistance "Ak = 0.0" is the summation of all the probabilities of occurrence of capacity outages equal to or greater than "R". This is because, for any capacity outage equal to or greater than "R", the capacity assistance is equal to zero.

The capacity assistance table can be converted back to a capacity outage probability table by simply substracting the amount of capacity of each assistance level from the reserve as shown in Table 2.5.

State	Capacity outage	Probability
1	$O1 = R - A1 \; (= 0)$	$P(O1)$
2	$O2 = R - A2$	$P(O2)$
.	.	.
.	.	.
.	.	.
j	$Oj = R - Aj$	$P(Oj)$
k	$Ok = R - Ak \; (= R)$	$\sum_{i=k}^{n} P(Oi)$

Table 2.5: Capacity outage probability table of System No.2 constrained to reseve capacity

Then, replacing the assistance levels "Ai" by their corresponding expressions given in the capacity assistance table yields the capacity outage table shown in Table 2.6.

State	Capacity outage	Probability
1	$O1$ (= 0)	$P(O1)$
2	$O2$	$P(O2)$
.	.	.
.	.	.
.	.	.
j	Oj	$P(Oj)$
k	Ok (= R)	$\sum_{i=k}^{n} P(Oi)$

Table 2.6: Equivalent assisting unit model of System No.2

This table is the equivalent assisting unit model of System No.2. It represents the assisting system as a generating unit of capacity "R" with "k" different outage states. In state No.1, the outage capacity is equal to zero, i.e., the "unit" is in the fully up state, supplying its full output. In state "k", the outage capacity is equal to "R" so that the "unit" is in the fully down state. In states 2 to "j", the "unit" is in partial output or derated state.

The equivalent assisting unit can now be "added" to the generating model of System No.1, the assisted system. Using the recursive method presented in section 2.2.2, this equivalent "unit" can thus be incorporated into the capacity outage probability table of System No.1 and the available capacity in that system is increased by "R".

The evaluation of the reliability indices may now proceed as if System No.1 were an isolated system. Sections 2.2.4 and 2.2.5 describe the methodology necessary to calculate LOLE and LOEE respectively.

2.3.2 Tie line capacity

Consider that the transmission line interconnecting System No.1 and System No.2 is a fully reliable tie line of finite capacity "Ct". In this case, the assistance capacity that System No.2 can provide to System No.1 is constrained to either the reserve "R" or the tie line capacity "Ct", whichever is less.

If the tie line capacity "Ct" were larger than the reserve "R", then the equivalent assisting unit model of System No. 2 would be the same as presented in section

2.3.1, i.e., a "unit" of capacity "R" with "k" different outage states. This is because the assisting system can provide a maximum capacity assistance equal to its reserve "R" and this amount is not limited by the tie line capacity "Ct".

However, a situation more often found in interconnected power systems is that the tie line capacity "Ct" is smaller than the reserve "R". In this case, the equivalent assisting unit model of System No.2 is constrained by the tie line capacity.

Consider the capacity assistance probability table presented in Section 2.3.1 (Table 2.4), a column may be included showing the level of capacity assistance when the tie-line capacity "Ct" is considered. The result is presented in Table 2.7.

State	Capacity assistance	Assistance constrained to tie capacity	Probability
1	A1 = R - O1 = R	Ct	P(O1)
2	A2 = R - O2	Ct	P(O2)
.	.	.	.
.	.	.	.
.	.	.	.
m	Am = R - Om	Ct	P(Om)
m+1	Am+1=R - Om+1	Am+1	P(Om+1)
.	.	.	.
.	.	.	.
.	.	.	.
j	Aj = R - Oj	Aj	P(Oj)
k	Ak = R - Ok = O	Ak	$\sum_{i=k}^{n} P(Oi)$

Table 2.7: Capacity assistance probability table of System No.2

In this table, the tie-line capacity "Ct" is assumed to be between the assistance levels "m" and "m+1".

In states "1" to "m", the assisting system is able to supply a capacity assistance "A1" to "Am" respectively, however, the tie-line does not allow a capacity assistance larger than its maximum transfer capability "Ct" to flow from the assisting system to the assisted system. Then, given that the level of assistance in states "1" to "m" is fixed to "Ct" these states can be combined into one single state, which yields the result shown in Table 2.8.

State	Cap. assistance	Probability
1 to m	Ct	$\sum_{i=1}^{m} P(Oi)$
m+1	Am+1 = R - Om+1	P(Om+1)
.	.	.
.	.	.
.	.	.
j	Aj = R - Oj	P(Oj)
k	Ak = R - Ok = 0	$\sum_{i=k}^{n} P(Oi)$

Table 2.8: Capacity assistance probability table constrained to tie-line capacity

This assistance table (Table 2.8) can be converted back to a capacity outage probability table by subtracting each level of capacity assistance from the maximum capacity assistance, which now corresponds to the tie-line capacity "Ct". The result is shown in Table 2.9.

State	Cap. on outage	Probability
1 to m	$Ct - Ct = 0$	$\sum_{i=1}^{m} P(Oi)$
m+1	$Ct - Am+1$	$P(Om+1)$
.	.	.
.	.	.
.	.	.
j	$Ct - Aj$	$P(Oj)$
k	$Ct - Ak = Ct$	$\sum_{i=k}^{n} P(Oi)$

<u>Table 2.9: Tie-line constrained equivalent assisting unit model of System No.2</u>

Table 2.9 is the equivalent assisting unit model of

System No.2 (the assisting system) constrained by given tie-line capacity.

For the purpose of an orderly presentation of the theory in the following sections, the table is reorganized as shown in Table 2.10.

State	Outage capacity	Probability
1	O1 (= 0)	P(O1)
2	O2	P(O2)
.	.	.
.	.	.
.	.	.
j	Oj	P(Oj)
k	Ok (= Ct)	P(Ok)

<u>Table 2.10: Tie-line constrained equivalent assisting unit model of System No.2</u>

In Table 2.10 the states have been simply re-numbered so that, State No.1 now represents all the states "1 to m" of the previous table while P(O1) corresponds to the sumation of their probabilities. Also, the probability of outage state "k" in Table 2.9 has been named "P(Ok)" in

Table 2.10.

The assumption of a 100% reliable tie-line is, of course, not strictly valid. A more realistic situation in this respect is discussed in the next Section.

2.3.3 Tie line reliability

Consider that the transmission line interconnecting System No.1 and System No.2 is of finite capacity "Ct" and that it is not a fully reliable tie line, i.e., it has an unavailability factor "FORt" greater than zero.

The tie line can exist in two states: the "fully up" state, in which the full capacity "Ct" can be transmitted, and the "fully down" state, in which the transmission line is out of service. The two-state model of the tie line can then be represented by a "tie line capacity outage probability table" (Table 2.11).

State	Tie capacity outage	Probability
1	0.0	1 - FORt
2	Ct	FORt

Table 2.11: Tie-line capacity outage probability table. Single tie-line

In order to include the tie line unavailability factor in assessing the equivalent assisting unit of System No.2, it is necessary to combine the capacity states of the tie line with those of the equivalent assisting unit obtained from the assisting system.

Consider the tie line constrained equivalent assisting unit derived in section 2.3.2 (Table 2.10). The combination of that table with the above tie line table can be carried out as follows.

First, create a probability array, which gives the probabilities of all possible events. Then identify the amount of capacity on outage corresponding to each event. (Refer to Table 2.12).

Equivalent unit capacity states	Tie capacity states 0.0	Ct	
	0.0	Ct	<-------------- event's outage
O1 (=0)	P(O1)(1-FORt)	P(O1)(FORt)	
	O2	Ct	
O2	P(O2)(1-FORt)	P(O2)(FORt)	
.	.	.	
.	.	.	
.	.	.	
	Oj	Ct	
Oj	P(Oj)(1-FORt)	P(Oj)(FORt)	
	Ct	Ct	
Ok (=Ct)	P(Ok)(1-FORt)	P(Ok)(FORt)	

Table 2.12: Tie-line and assisting unit states

Note: The capacity on outage of each event (the event's outage) is given by the largest of either the tie line outage capacity or the equivalent assisting unit outage capacity.

Second, obtain the capacity outage probability table from the probability array by taking each event's outage capacity together with its probability of occurrence and arranging the events as shown in Table 2.13.

State	Outage capacity	Probability
1	O1 (= 0)	P(O1)(1-FORt)
2	O2	P(O2)(1-FORt)
.	.	.
.	.	.
.	.	.
j	Oj	P(Oj)(1-FORt)
k	Ok (=Ct)	$P(Ok)(1-FORt)+FORt \sum_{i=1}^{k} P(Oi)$

Table 2.13: Capacity outage probability table constrained by tie-line capacity and unavailability factor

The summation of all the probabilities "P(Oi)" in outage state "k" is, by definition, equal to unity because it represents the summation of all the probabilities of outage events in the generating system. Therefore, the equivalent assisting unit model of System No.2 constrained to tie line capacity "Ct" and including tie line unavailability "FORt" is as shown in Table 2.14.

State	Outage capacity	Probability
1	O1 (= O)	P(O1)(1-FORt)
2	O2	P(O2)(1-FORt)
.	.	.
.	.	.
.	.	.
j	Oj	P(Oj)(1-FORt)
k	Ok (=Ct)	P(Ok)(1-FORt) + FORt

Table 2.14: Equivalent assisting unit model of System No.2 constrained to tie-line capacity and unavailability factor

2.3.4 Number of tie lines

When more than one tie-line interconnects System No.1 and System No.2, the tie line capacity outage probability table is not as simple as that given in Table 2.11. Instead, the tie table can be made up of many capacity outage levels. In fact, the number of levels can be "2 to the power n", where "n" is the total number of tie lines.

Whatever the number of capacity outage levels, the process to obtain the equivalent assisting unit model of the assisting system (including all the tie lines) is the same as that presented in section 2.3.3. The only difference is that the probability array in this case has "k x n" outage events instead of "k x 2" outage events for the case of one tie line.

For the purpose of this discussion, consider System No. 1 and System No.2 interconnected by two tie lines of capacities C1 and C2 and unavailability factors FOR1 and FOR2 respectively. Also, assume C2 > C1 and Ct = C1 + C2 is the total interconnecting capacity between the systems, as shown in Fig. 2.8.

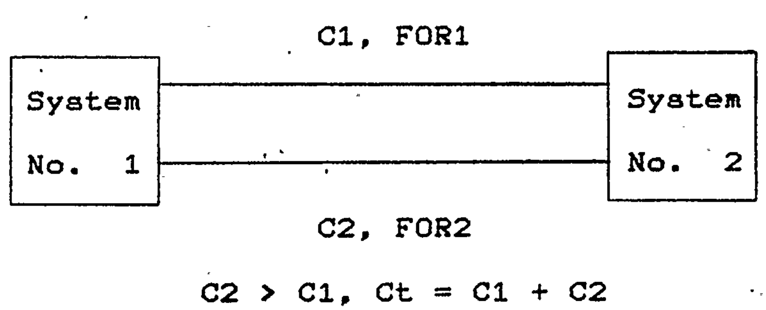


Figure 2.8: Interconnection by 2 tie lines

The tie line capacity outage probability table can be derived in the same manner as for the generating units, by either identifying all the outage states or by "adding" one tie line at a time using the recursive method explained in section 2.2.2. Refering to the system in Figure 2.8, the outage states and associated probabilities may be identified as shown in Table 2.15.

Tie line on outage	Tie line Cap. on outage	Probability
None	0.0	P'(0)=(1-FOR1)(1-FOR2)
Tie No. 1	C1	P'(C1)=(FOR1)(1-FOR2)
Tie No. 2	C2	P'(C2)=(1-FOR1)(FOR2)
Both	Ct =C1+C2	P'(Ct)=(FOR1)(FOR2)

Table 2.15: Tie-lines capacity outage probability table. Case with two tie-lines

It will be assumed that outage level "C1" is immediately lower than outage level "Oj" and that outage level "C2" is immediately higher than outage level "Oj". Then, the probability array for the combined tie table and the equivalent unit table is:

Eq.unit states	Tie capacity states 0.0	C1	C2	Ct
	0.0	C1	C2	Ct
O1 (=O)	P(O1)P'(O)	P(O1)P'(C1)	P(O1)P'(C2)	P(O1)P'(Ct)
	O2	C1	C2	Ct
O2	P(O2)P'(O)	P(O2)P'(C1)	P(O2)P'(C2)	P(O2)P'(Ct)
.	.	.	.	.
.	.	.	.	.
.	.	.	.	.
	Oj	Oj	C2	Ct
Oj	P(Oj)P'(O)	P(Oj)P'(C1)	P(Oj)P'(C2)	P(Oj)P'(Ct)
	Ct	Ct	Ct	Ct
Ok(=Ct)	P(Ok)P'(O)	P(Ok)P'(C1)	P(Ok)P'(C2)	P(Ok)P'(Ct)

Table 2.16: Tie-lines and assisting unit states

The outage table obtained from the above probability array is given in Table 2.17.

State	Outage capacity	Probability
1	O1 (=O)	$P(O1)P'(O)$
2	O2	$P(O2)P'(O)$
.	.	.
.	.	.
.	.	.
(new)	C1	$P'(C1)\sum_{i=1}^{j-1} P(Oi)$
j	Oj	$P(Oj)[P'(O)+P'(C1)]$
(new)	C2	$P'(C2)\sum_{i=1}^{j} P(Oi)$
k	Ok (=Ct)	$P(Ok)[P'(O)+P'(C1)+P'(C2)]+P'(Ct)$

Table 2.17: Equivalent assisting unit model of System No.2 constrained to tie-line capacities and unavailability factors

Apart from power transmission limits related to physical constraints, utilities may regulate power flow levels as a matter of contract or agreement. This aspect is discussed in the next Section.

2.3.5 Firm capacity contracts

The equivalent assisting unit approach can also be used to analyse the effect of interconnection agreements on the reliability of the generating capacity. Many agreements between different utilities can exist and it is not possible to discuss them exhaustively in this report. However, a very basic and common agreement, the firm capacity contract, is considered in this section. The use of the equivalent assisting unit approach subject to interconnection agreements will be illustrated. It is possible that Alberta may have agreements of the firm capacity type with B.C. and/or Saskatchewan in the future. (Reference [9] extends the analysis to other types of capacity contracts).

Let us assume that System No.1 has a firm purchase capacity contract of "Cc" MW with System No.2. This means that System No.2 guarantees that amount of capacity assistance to System No.1, regardless of its reserve, and also regardless of difficulties that it could experience during the duration of the contract.

For modeling purposes, the firm capacity "Cc" is assumed fully reliable at the sending end of the transmission line that interconnects the assisting system with the assisted system. Then, the capacity outage probability table that represents the firm capacity at the sending end is:

State	Outage capacity	Probability
1	0.0	1.00
2	Cc	0.00

<u>Table 2.18: Capacity outage probability table of firm capacity assistance at sending end of tie-line(s)</u>

If the tie line were a fully reliable transmission line, the above table would be the equivalent assisting unit model of the firm capacity assistance of System No.2 and it could be "added" to System No.1. In this case, given that this equivalent unit can exist only in one state (outage = 0, probability = 1), the addition of this equivalent unit to the capacity outage probability table of System No.1 will produce no changes in the probability of outages, only the available capacity in that system will increase by "Cc" MW because a "fully reliable unit" is being added.

If there were only one tie line with an unavailability factor "FORt", then the firm capacity assistance "Cc" would be subject to outages on the tie line. In this case, it is necessary to combine the tie line capacity outage table with the firm capacity equivalent assisting unit (valid at the sending end of the tie line), in order to incorporate the reliability of the tie line in the equivalent assisting unit model.

Consider the tie line capacity outage probability table (Table 2.11) presented in section 2.3.3. That table combined with the outage table of the firm capacity equivalent unit gives:

State	Outage capacity	Probability
1	0.0	1 - FORt
2	Cc	FORt

Table 2.19: Equivalent assisting unit of firm capacity assistance. Case with one tie-line

The above table is the equivalent assisting unit model of the firm capacity assistance considering tie line unavailability. This "unit" can now be "added" to the generating system of System No.1.

In the case of more than one tie line, the same process should be followed. The only difference is that the tie line table will have several states, and combining the tie table with the firm capacity outage table will involve more events than in the case of one tie line. The situation was discussed in section 2.3.4 above, which presents a case with two tie lines.

After the firm capacity equivalent assisting unit has been added to the generating system of System No.1, there could be further assistance capacity, depending on the following conditions.

- If Cc < Ct < R, then a capacity assistance of Ct-Cc MW is still possible.

- If Cc < R < Ct, then a capacity assistance of R-Cc MW is still possible.

In both cases, the capacity assistance added to the firm capacity is not under the contractual agreement, so it has to be treated as capacity assistance subject to availability and random outages on the assisting system. Then, an equivalent assisting unit model of the capacity assistance added to the firm capacity can be obtained as described in sections 2.3.1 to 2.3.4, and it can be added to the generating capacity of System No.1.

Chapter III

A COMPUTER MODEL FOR RELIABILITY ASSESSMENT OF INTERCONNECTED POWER SYSTEMS

3.1 INTRODUCTION

The computer model developed for reliability assessment of interconnected systems is composed of two separate programs.

- The Isolated System Program. (Is.Pgm.).

- The Interconnectd Systems Program. (In.Pgm.).

Both programs are written in FORTRAN 77 and were compiled using an IBM mainframe computer.

The model performs a yearly calculation of reliability indices. These indices are the Loss of Load Expectation (LOLE) and the Loss of Energy Expectation (LOEE). The year can be divided into a number of periods selected by the user, and reliability calculations are carried out for each period. The annual reliability indices are the sum of the indices calculated for each period. References [10] and [11] present insights for the design and application of generation planning programs.

The Is.Pgm., as its name suggests, treats each individual power system as an isolated system. If, for instance, a study involves three interconnected systems, then it is necessary to execute the Is.Pgm. three times, one for each power system. In each run, the Is.Pgm. creates a magnetic disk file containing the necessary information to execute the In.Pgm. later.

The major functions of the Is.Pgm. are:

- to read and check the input data,
- to determine a maintenance schedule for thermal plants,
- to determine the capacity output of hydroelectric plants,
- to build the capacity outage probability table,
- to create a magnetic disk file containing appropriate information to execute the In.Pgm, and
- to calculate the LOLE and LOEE of the isolated system.

The In.Pgm. reads the magnetic disk files created in each run of the Is.Pgm. It also reads data related to tie lines and interconnection agreements. The program then carries out the yearly calculation of reliability indices considering the effect of interconnections between power systems. Its major functions are:

- to read and check input data,
- to open and read the disk files of systems to interconnect,
- to calculate the equivalent assisting units of assisting systems, recognizing constraints and certain types of agreements,
- to add the equivalent assisting units to the capacity outage probability table of the specified system under study, and
- to calculate the LOLE and LOEE of the system under study.

Fig. 3.1 presents a diagram of the operation of the model for a case of three interconnected systems, labeled A, B, and C.

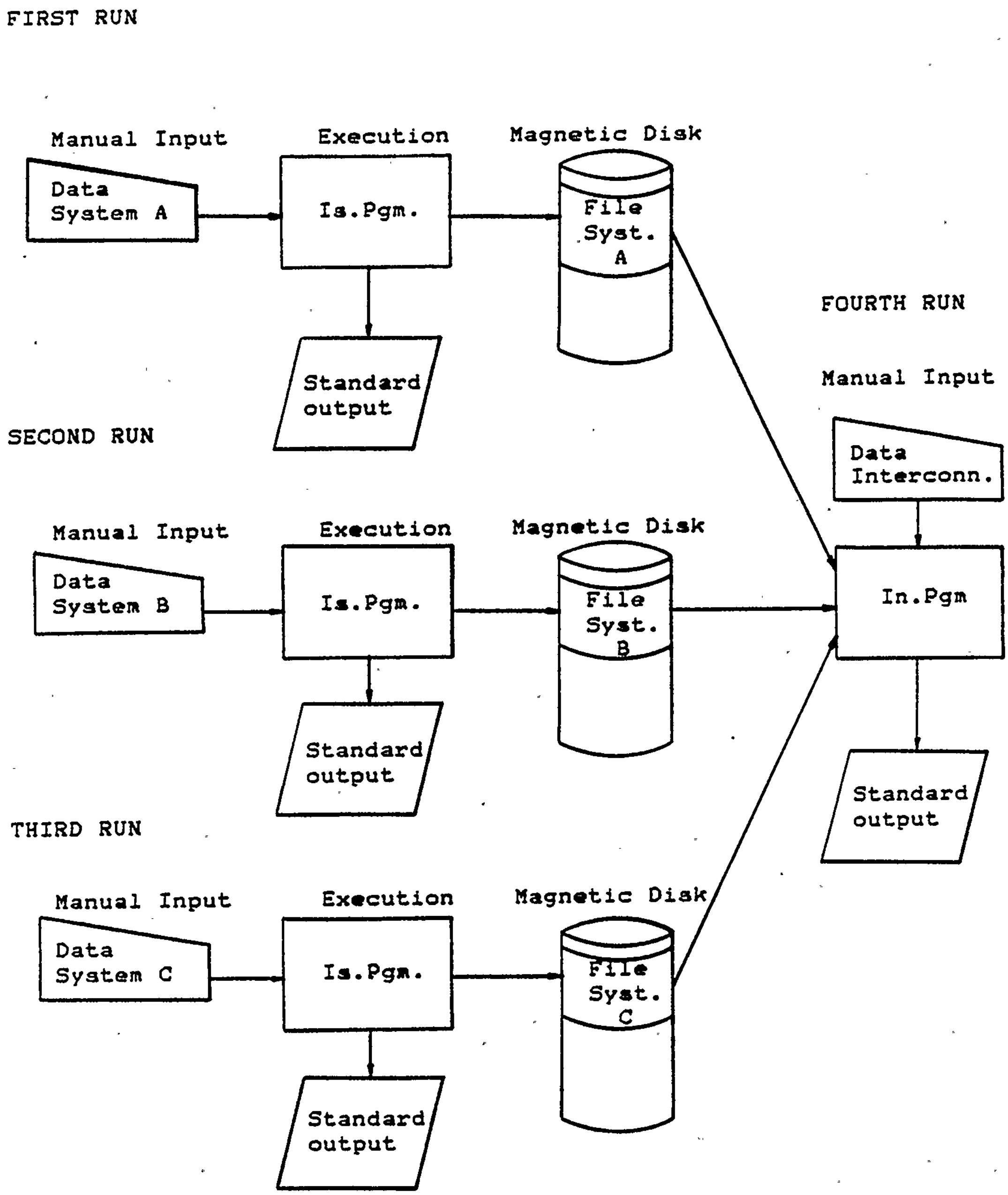


Figure 3.1. Operation of the model for 3 interconnected systems

3.2 ISOLATED SYSTEM PROGRAM

The basic sequential functions of the Is.Pgm. are outlined in the steps following.

- The program reads system data, such as generator characteristics, load duration curves for each period, etc. It also reads a set of parameters that controls the execution of the program.

- A maintenance schedule is determined for the thermal generating units.

- The program determines the output capacity of the hydroelectric generating units to meet the expected hydro-energy production.

- The program builds the capacity outage probability table of the generating system. The table incorporates the effect of scheduled outages due to maintenance.

- Information needed to execute the In.Pgm. is created and written onto a magnetic disk file.

- As an option, the program calculates the reliability indices of the isolated system, combining the load characteristics with the capacity outage probability table.

The above functions are performed by the MAIN program and the subroutines INGM, INLM, INOP, MAINT, HYD, and RELIN.

The MAIN program controls the overall operation of the program and calls the subroutines. It also reads the top portion of the input data file, writes the magnetic disk file used by the In.Pgm, and prints the annual LOLE and LOEE.

Subroutines INGM, INLM, and INOP read and check the input data. INGM (INput Generation Model) reads and checks the generator characteristics. INLM (INput Load Model) reads and checks the load characteristics. INOP (INput OPtions) reads and checks parameters that control the various options and features of the program.

Subroutine MAINT produces a maintenance schedule for the thermal units of the system.

Subroutine HYD calculates the output capacity of the hydroelectric system such that expected energy production in each period is satisfied. HYD also modifies the Load Duration Curves (LDC) by removing the energy supplied by hydro plants from the load of the system.

Subroutine OUTAB (OUtage TABle) builds the capacity outage probability table in each period of the year.

Subroutine RELIN (RELiability INdices) calculates the LOLE and LOEE in each period.

Fig. 3.2 presents a flow chart of the MAIN program showing the sequence in which each subroutine is called. Various aspects of the program and the analysis performed are discussed further in Subsections 3.2.1 - 3.2.7 below.

3.2.1 Input data

A list summarizing the input data to the In.Pgm. is presented as follows.

General data,

- Description of the study

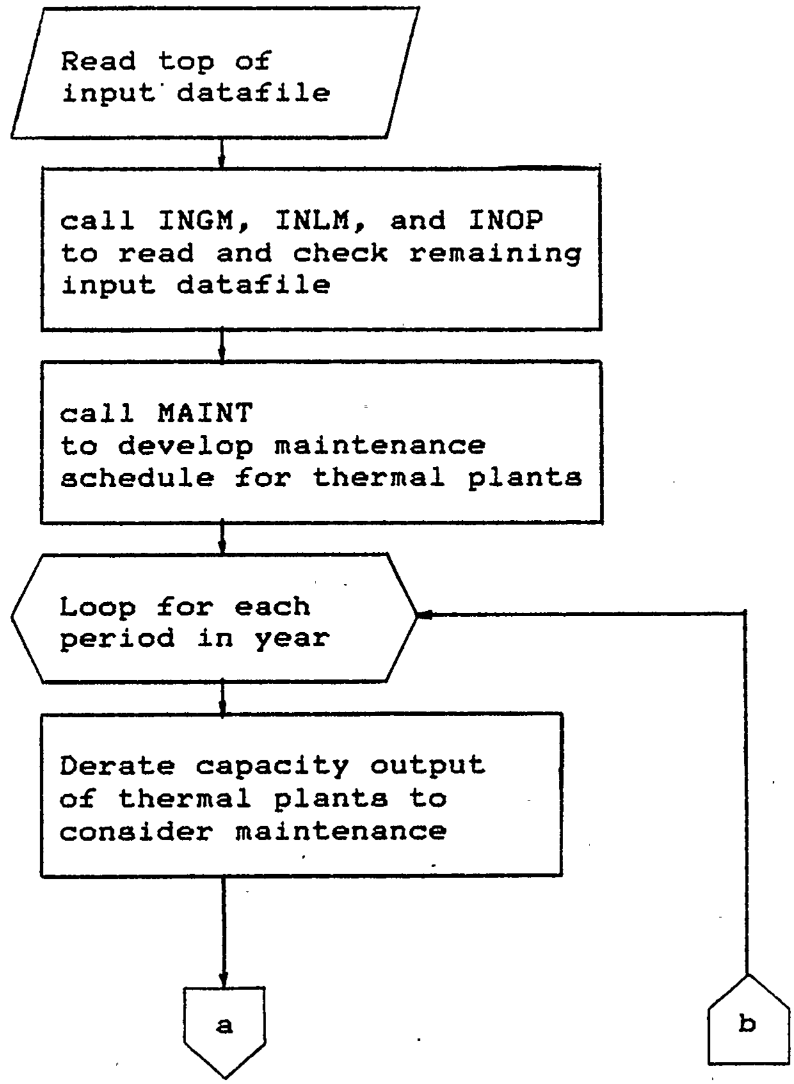


Figure 3.2: Isolated System Program Flow Chart

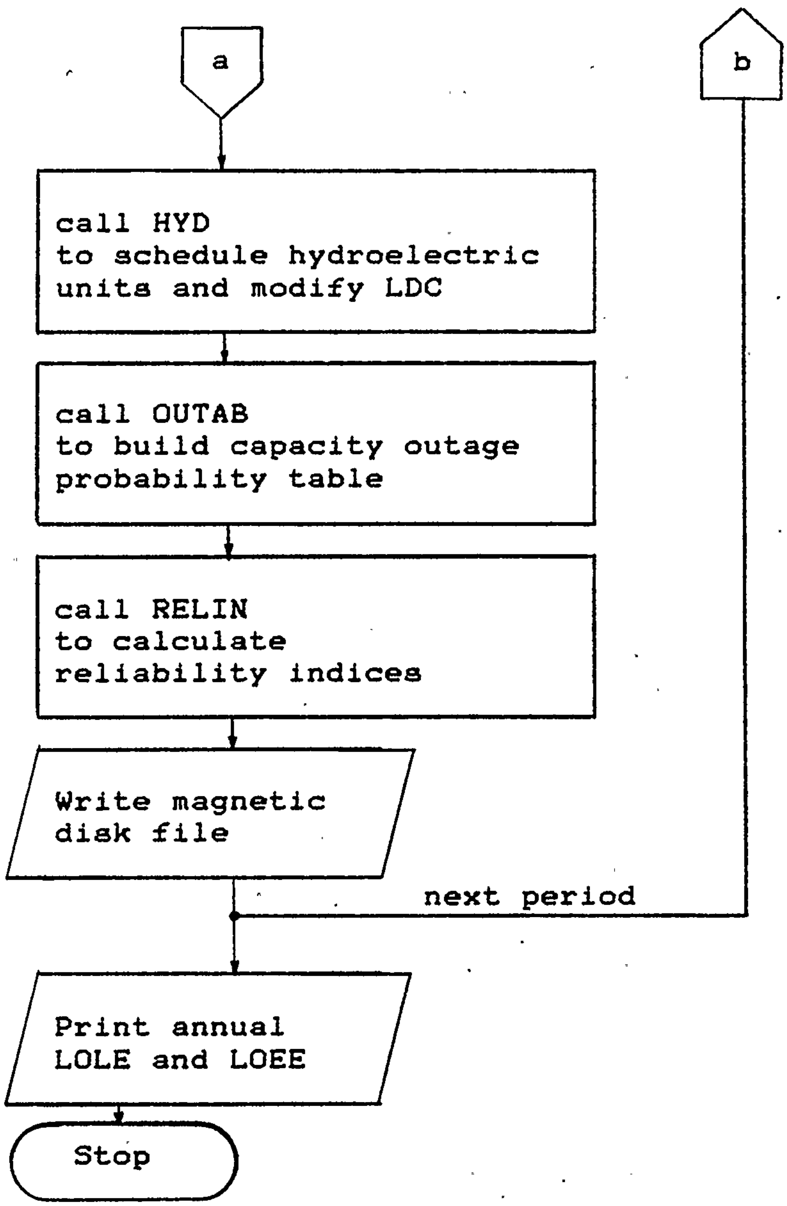


Figure 3.2 (cont'd): Isolated System Program Flow Chart

- Number of periods per year (1, 2, 3, 4, 6, or 12)
- Forecast of annual peak loads (Up to 30 years)

Thermal plants (up to 100), for each generator,

- Name
- Output capacity (MW)
- Forced outage rate, FOR,(per unit)
- Planned outage rate, POR,(per unit)
- Maintenance class (MW)

Composite hydro plant, for each period of the year,

- Minimum output capacity (MW)
- Maximum output capacity (MW)
- Expected electric energy generation (GWh)

Load model, for each period of the year,

- Ratio period peak / annual peak (per unit)
- Period length (hours)
- Load duration curve (per unit) as a discrete set of points (up to 40 points)

Options,

- Maximum allowed number of capacity levels in the capacity outage probability table (max. 2000)
- Minimum probability to end calculation of outage

table (per unit)

- Minimum allowed capacity step for the outage table
- Option to print outage table
- Option to develop maintenance schedule
- Option to preclude maintenance in a specific period
- Option to perform calculations for composite hydro plant
- Options to request calculation of LOLE and/or LOEE
- Option to request detailed output
- Specification of study years
- Option to write output onto magnetic disk file

3.2.2 Maintenance schedule

Prior to performing any reliability calculation, a maintenance schedule must be prepared. It will affect equipment availability in each of the time periods. The information needed includes the specified time requirements for scheduled outages (given by the POR's), the maintenance class associated with each unit, and the reserve capacities in each of the time periods.

The algorithm, which has been extracted from reference

[12], schedules maintenance for the units belonging to the largest maintenance class in the periods where the reserves are the greatest. For the units of the second largest maintenance class, maintenance is scheduled in the periods where the remaining reserves are greatest, and so on.

The algorithm begins by calculating the reserve for each period as follows.

Reserve = Installed capacity - Peak load

The total maintenance requirements for a particular class is calculated by,

$$MWDAYS = \sum PCRi * MAINTi$$

= Total maintenance requirement of maintenance class, MW-days

PCRi = Capacity of unit "i", MW

MAINTi = Maintenance requirement, days per year

i = Index of units in maintenance class

A maintenance block represents the amount of maintenance that could be performed by the removal of a specific capacity for the entire period:

MAINTBK = MAINTCL * Tp

= Maintenance space available in one maintenance block, MW-days

MAINTCL = Capacity of maintenance class

Tp = Length of period, days

The number of blocks required for each maintenance class is calculated as,

No = MWDAYS / MAINTBK

The blocks are assigned sequentially to the period that has the largest maintenance space. An approximation must be made for a fractional block (i.e. when the number of blocks is not an integer). It is not possible to subdivide the period, therefore, for any remaining maintenance, the class size must be adjusted to allow the maintenance to extend over the entire period. The capacity of the fractional block is calculated as follows.

CFB = REMAIN / Tp

= Estimated capacity for fractional maintenance block, MW

REMAIN = Maintenance requirement for fractional block, MW-days

A probability distribution of performing maintenance for a particular maintenance class is determined by,

$$Pi = Ni / No$$

= Probability of performing maintenance for class in period "i"

Ni = Number of maintenance blocks scheduled in period "i"

No = Total number of maintenance blocks.

Finally, in every period of the year the capacity of each unit is derated according to the probability of maintenance and the maintenance requirement, i.e.,

$$PCRn' = PCRn * (1 - Pi*MAINTn/Tp)$$

Where PCRn' & PCRn are the derated & original peak continuous rating of unit "n" respectively.

3.2.3 Treatment of hydroelectic plants

The Is.Pgm. treats the hydroelectric plants as one single composite plant, which is considered fully reliable and with no maintenance requirements. References [12] and [13] show the application of this treatment of hydro plants by two commercial computer models.

These assumptions are valid for the power systems in Alberta and Saskatchewan, which have relatively small hydro capacity compared to installed thermal capacity. However, for a power system such as British Columbia's, which is composed almost entirely of hydro facilities, the assumptions are not valid. In this case, hydro plants have to be treated as if they were thermal plants and, if applicable, their output capacity should be penalized to account for water shortages.

There are generally two types of conventional hydro plants. The first, run-of-river hydro, is typically an installation which has minimal storage and probably a low head. Units in this type of installation tend to be base loaded, because the river flow and reservoir characteristics dictate continuous operation. The second type of conventional hydro is the pondage or simple storage hydro. Units in these installations are usually scheduled during peak load time periods because the system's incremental fuel cost is highest at these times.

The run-of-river energy produced by the associated type of hydro units is accounted for by subtracting a constant capacity from every hourly load in the period. This capacity value is provided as input data. After run-of-river energy is used, there may be remaining energy which can be used for peak shaving. In such situations, the program uses the remaining capacity and energy of the hydro unit to reduce the peak loads as much as possible.

After the program calculates the schedule of hydro energy production, it proceeds to remove the loads supplied by hydro facilities from the LDC. The resultant LDC represents the loads that have to be supplied by the thermal plants, and the reliability calculations are carried out combining this modified LDC with the capacity outage probability table of the thermal generating system.

The hydro schedule is developed for each period of the year (and is carried out) by the subroutine HYD. This subroutine receives (from the MAIN program,) the LDC, peak load, and length of time corresponding to the period for which a hydro schedule is to be developed. It also receives the necessary data that describes the behaviour of the composite hydroelecric plant. These data are,

- The minimum output capacity, MW
- The maximum output capacity, MW
- The expected electric energy generation, MWh.

The minimum output capacity represents the run-of-river portion of the composite hydro plant, and its value is normally dictated by the river flow rate and/or the characteristics of the reservoir. Also, the supply of water downstream from the dam is a factor that should be considered when determining the minimum output of a hydro plant.

The maximum output capacity is normally given by the generator rating. However, in some cases during the winter periods, the maximum output is derated due to formation of ice on the reservoir.

The expected electric energy generation, as its name suggests, is a figure arrived at statistically, considering the past hydrological conditions and weather patterns of the region.

It is worth noting that, although the Is.Pgm. assumes a fully reliable hydroelectric system, forced outages of the hydro plants can be accounted for by derating the maximum and minimum output capacities proportionally to their FOR's.

Derated capacity = (1 - FOR) * Output capacity

The algorithm begins by calculating the run-of-river energy, or "base energy" (because it is used to supply base loads) i.e.,

Base energy = Minimum capacity * Length of time.

The remaining energy and capacity available for peak shaving is determined,

Available energy = Expected energy - Base energy

Available capacity = Maximum output - Minimum output.

The algorithm now starts an iterative process in which it schedules capacity to "peak shave" the LDC and calculates the associated energy. At the end of each iteration, it compares the scheduled capacity and associated energy to the available capacity and available energy respectively. The following situations may arise,

i) Scheduled capacity < Available capacity
   Associated energy < Available energy.

In this situation, the program increases the scheduled capacity and it starts a new iteration.

ii) Scheduled capacity < Available capacity
    Associated energy = Available energy.

In this case, all the available energy has been generated and no further capacity can be sheduled. The iterative process ends and the algorithm now proceeds to modify the LDC in order to remove the loads supplied by hydro plants, as shown in Fig. 3.3.

iii) Scheduled capacity = Available capacity
     Associated energy < Available energy.

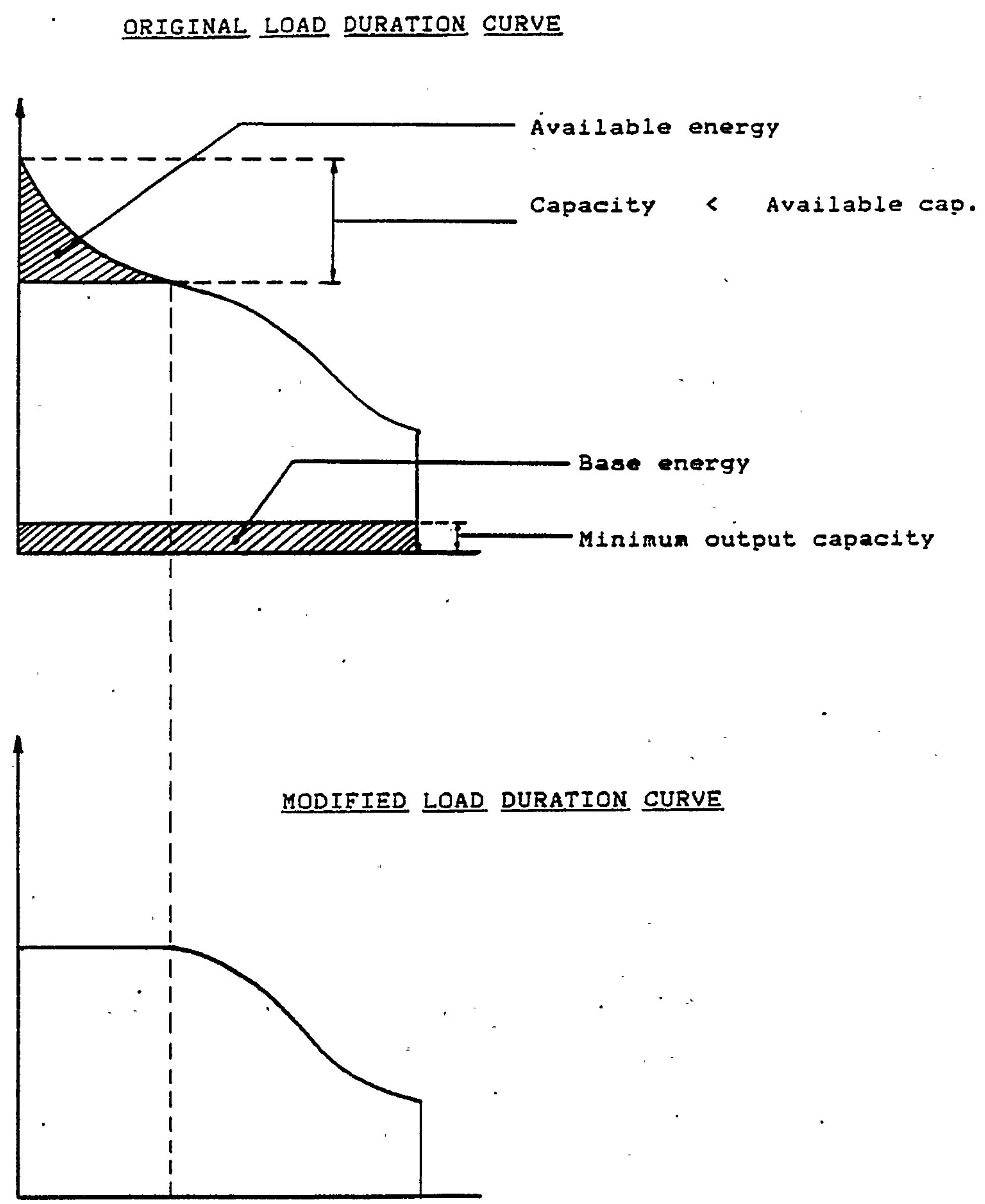


Figure 3.3: Hydroelectric schedule to "peak shave" the LDC, and load modification

In this case, all the available capacity has been scheduled to peak shave the LDC, but the available energy has not been totally exhausted. Therefore, the algorithm moves the scheduled capacity to a lower point in the LDC, such that the associated energy produced matches the available energy. In this type of situation, the hydro plants are no longer scheduled to "peak shave" the LDC, but to "off-load" the thermal plants. The iterative process ends and the program proceeds to modify the LDC, as shown in Fig. 3.4.

3.2.4 Capacity outage probability table algorithm

The capacity outage probability table is built by the subroutine OUTAB in each period of the year. The subroutine implements the recursive method presented in Chapter 2, section 2.2.2.

The algorithm builds the table by adding one unit at a time to the existing table. Before any unit is added, the outage table contains one single capacity level, i.e. capacity on outage = 0.0, with probability of occurrence = 1.0. The table is completed after the last generating

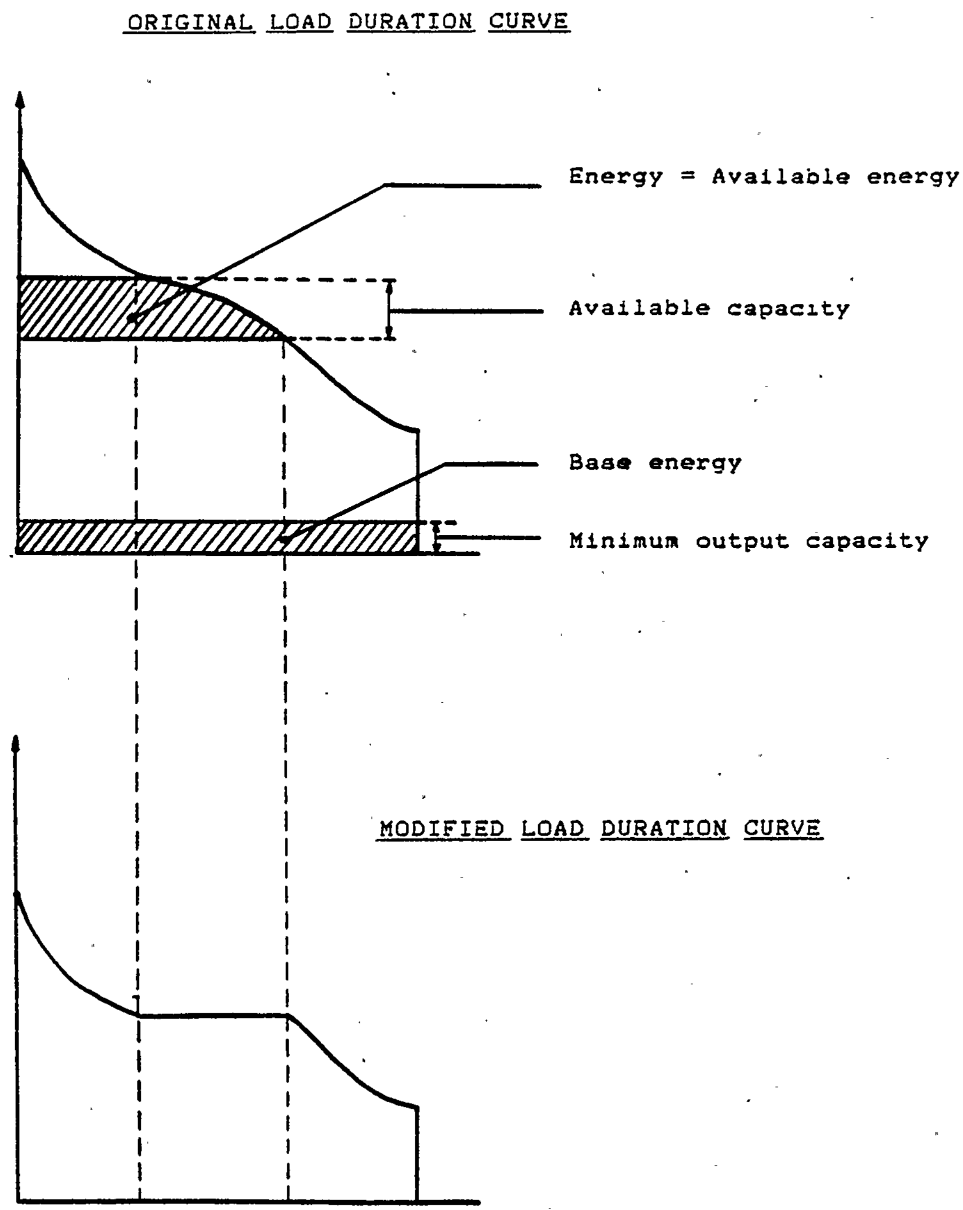


Figure 3.4: Hydroelectric schedule to "off—load" thermal plants and load modification

unit has been added to the table.

The subroutine can be described as being composed of three major sections. In the first section the probability of outage of the existing capacity levels in the table are recalculated each time a generating unit is added. In the second section the algorithm determines new outage capacity levels and calculates their corresponding probability of occurrence. The new levels are added to the bottom of the existing table. In the last section, after all generating units are added, the algorithm sorts the table, arranging the outage capacity levels in ascending order.

To limit the number of capacity levels in the table, the subroutine has two built-in features.

a) If, when adding a unit, a new capacity level results closer to an existing capacity level than a user-specified capacity step, then the new level is simply disregarded.

b) If, after adding several units, the probability calculated for a new capacity level is smaller than a user-specified value, the table is considered completed.

(typical values to complete the table are 1.0*E-8 to 1.0*E-6).

The subroutine also has a safety feature that stops execution and prints an error message when the number of capacity levels surpasses a user-specified maximum value.

Figure 3.5 shows the flow chart of subroutine OUTAB.

3.2.5 Reliability indices algorithm

The reliability indices are calculated by the subroutine RELIN in each period of the year. In order to calculate the Loss of Load Expectation and the Loss of Energy Expectation, RELIN implements the methods described in Chapter 2, section 2.2.4 and section 2.2.5 respectively.

The algorithm that computes the LOLE begins calculating the reserve capacity in each hour of the period by subtracting the hourly load from the available capacity. The hourly loads are obtained from the modified LDC and the available capacity is the total installed

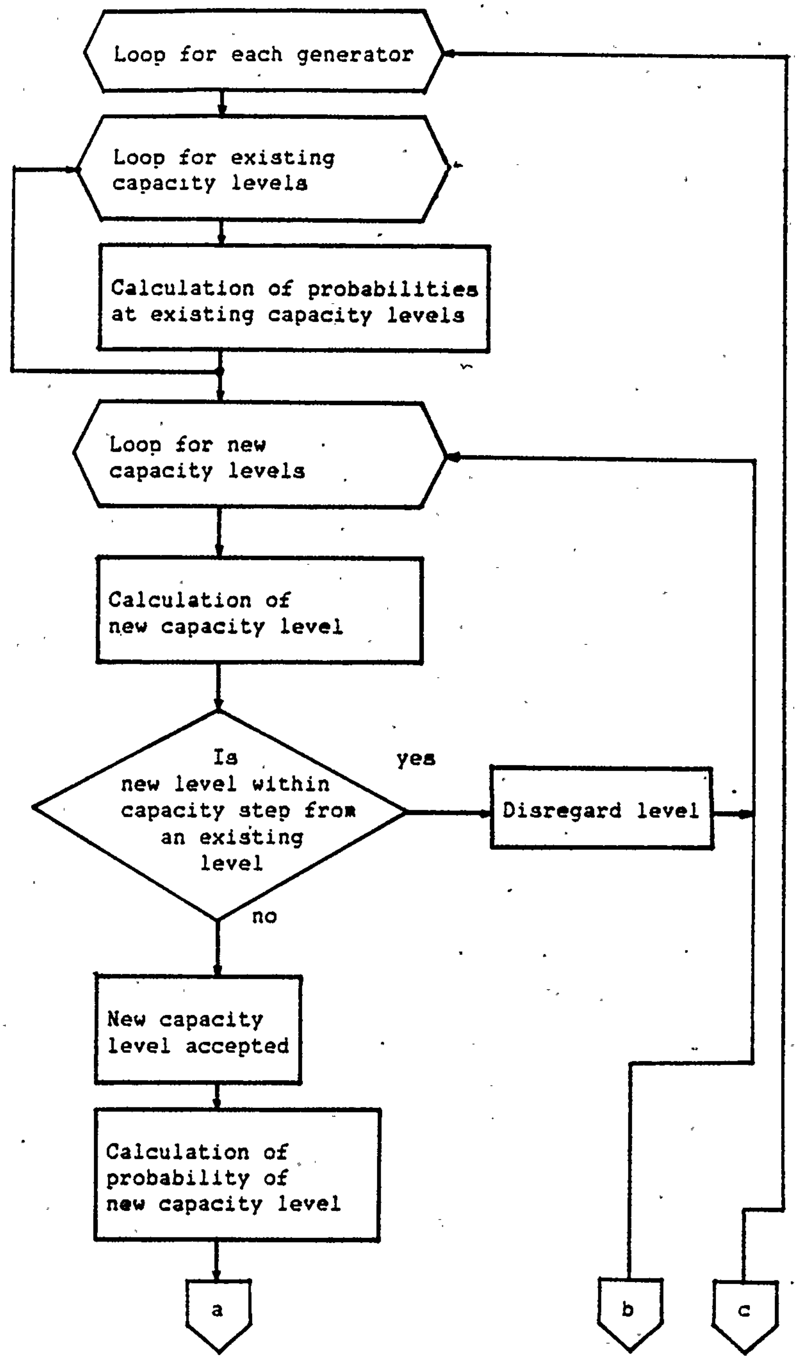


Figure 3.5: Flow chart of subroutine OUTAB

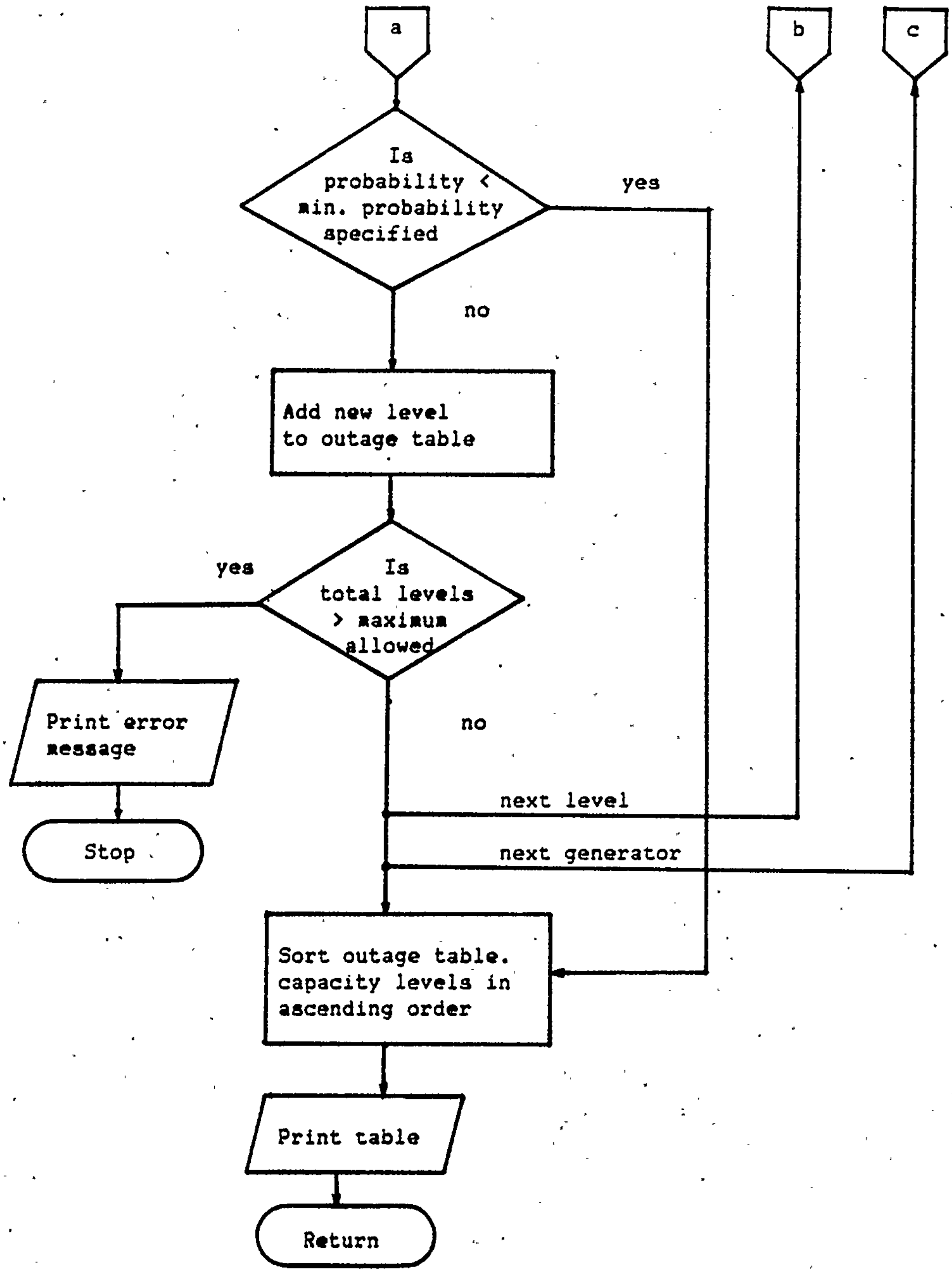


Figure 3.5 (cont'd) Flow chart of subroutine OUTAB

thermal capacity, derated to account for maintenance as described in section 3.2.2.

Once the reserve at a specific hour is known, the algorithm obtains the probability of outage of a capacity equal to or larger than the reserve at that hour from the capacity outage probability table. This value is the probability of loss of load at that hour. To compute the LOLE, the algorithm adds the hourly loss of load probabilities calculated througout the entire period.

The LOLE algorithm has a built-in feature that stops the calculations when an hourly loss of load probability becomes smaller than the minimum probability specified by the user.

The algorithm that computes the LOEE begins calculating the hour of the period at which the corresponding reserve is the closest to the first outage capacity level in the outage table. It then proceeds to calculate the energy curtailment associated with the first outage of capacity and it multiplies the calculated energy by the probability of occurrence of the capacity outage.

The algorithm repeats the process for the second level of outage capacity of the table, and so on, until it covers all the capacity levels in the outage table. Then the algorithm computes the sum of all the "energy-probability" products, which represents the expected value of energy not supplied in the period, or the period LOEE.

Fig. 3.6 presents the flow chart of subroutine RELIN.

3.2.6 Reporting capabilities

The IS.Pgm. produces a report which contains the following sections.

- A reproduction of the input data file
- Maintenance schedule
- Hydroelectric schedule for every period of the year
- Capacity outage probability table for every period
- Reliability indices for every period
- Summary of annual reliability indices

The size of the report depends on the options and features used in the execution of the program. The

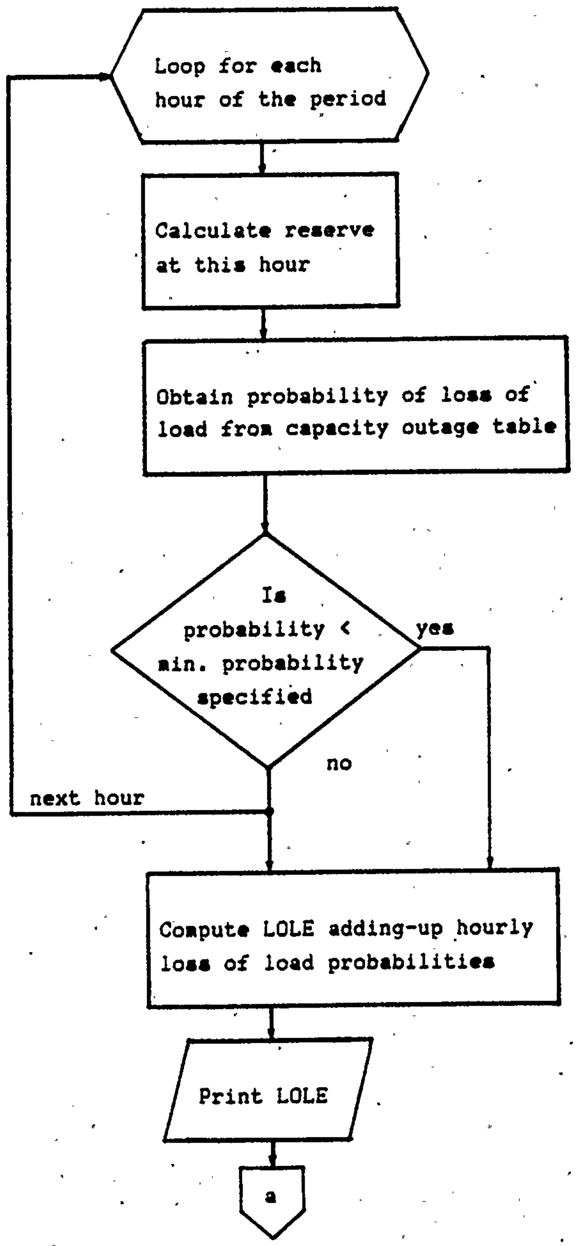


Figure 3.6: Flow chart of subroutine RELIN

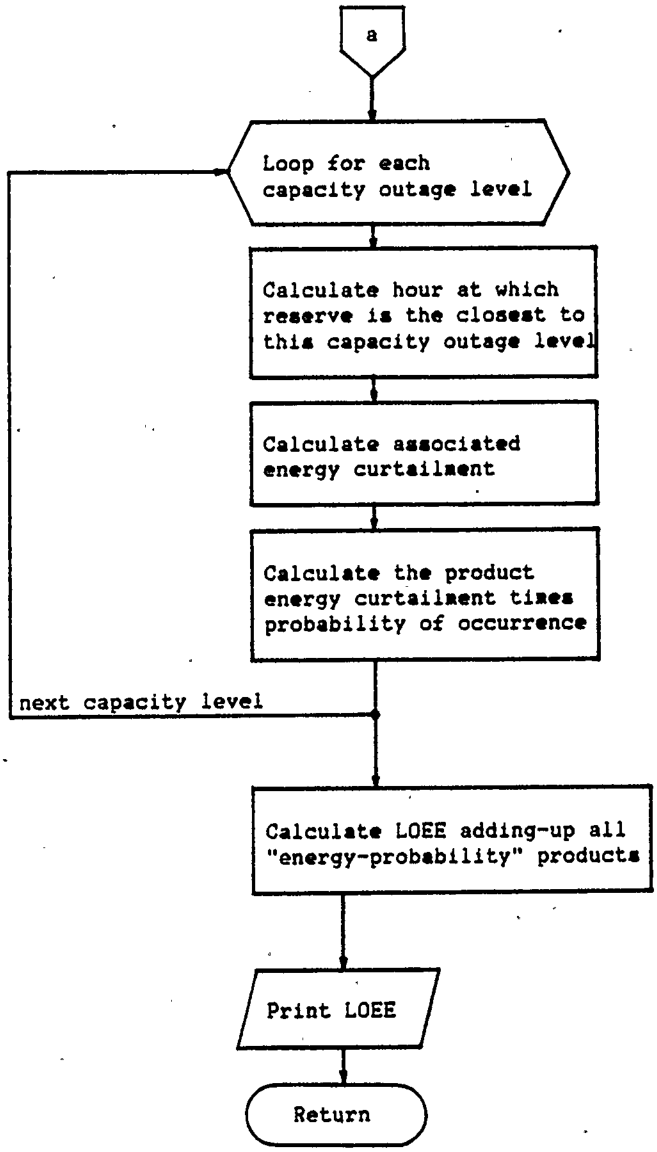


Figure 3.6 (cont'd). Flow chart of subroutine RELIN

reproduction of the input data file as well as the summary of annual reliability indices are always printed. The maintenance and hydroelectric schedules are printed only if they are developed by the program. The capacity outage probability table and the reliability indices, calcualted in each period, can be printed in detail or in summary form, depending on the option selected by the user.

The reproduction of the input datafile is intended to allow the user to verify the input data after execution of the Is.Pgm.

The maintenance schedule contains the following information.

- A table showing the peak demand, installed capacity, and reserve capacity for each period of the year.

- As many tables as there are maintenance classes defined in the generator data, starting with the largest maintenance class. Each table contains the maintenance schedule for generators belonging to a particular maintenance class. The information in this tables is,

- the maintenance blocks assigned to each period

- the probability of maintenance in each period, and
- the maintenance space available for the next class.

The hydroelectric schedule is developed in each period of the year and it contains the following information.

- The characteristics of the composite hydro plant, namely the minimum output , the maximum output, and the expected energy production (input data).

- The period peak demand (MW) and period length (hours).

- The calculated energy demand in the period (GWh) and load factor (in per unit).

- The energy and capacity allocated to base generation.

- The energy and capacity available for "peak-shaving".

- The actual energy and capacity scheduled by the program to either "peak-shave" the LDC or to "off-load" thermal plants.

- The coordinates on the LDC, where the capacity is scheduled.

- The modified LDC, i.e., the resultant LDC after the energy supplied by hydro plants has been removed from the load.

The detailed report on the capacity outage probability table contains two subsections.

a) A subsection containing the following information:
   - total number of capacity levels
   - maximum allowed number of capacity levels
   - minimum probability specified to end the table
   - capacity level at which the minimum probability was reached.

b) The table itself, in the form of a matrix of 6 columns and as many rows as necessary to cover all the capacity levels and their corresponding probability.

The summary output contains only the information in (a) above, while the table itself is omitted.

The report on the calculations of reliability indices, printed in detailed form, contains the following information.

a) The hour by hour calculation of loss of load probability, which shows in each line,

- the hour
- the reserve at this hour
- the loss of load probability for this hour, and
- the cumulative loss of load probability computed up to this hour.

This section of the report has as many lines as hours in the period for which the calculated loss of load probability is larger than the minimum probability specified by the user.

b) The LOLE for the period.

c) The level by level calculation of energy not supplied, which shows in each line:

- the capacity level,
- the hour at which the reserve is the closest to the capacity outage level,
- the energy associated with an outage equal to the

capacity level,

- the product "energy-probability", referred to as the energy not supplied, and
- the cumulative "energy-probability" products, computed up to this capacity level.

This section of the report has a number of lines equal to the number of capacity levels of the outage table for which the "energy-probability" products are larger than the minimum probability specified by the user.

d) The LOEE for the period.

The summary output, if requested by the user, shows only the LOLE and the LOEE for the period. It omits the report on hourly calculations of loss of load probabilities as well as the level by level computation of energy not supplied.

The summary of annual reliability indices contains the annual LOLE, in hours/year and in days/year, as well as the annual LOEE in MWh.

3.2.7 Tests

This section presents the tests conducted to evaluate the accuracy of the Is.Pgm. The tests consist of comparisons of results obtained using this program and results supplied by the IEEE for its Reliability Test System (RTS). The following list summarizes the tests conducted on the Is.Pgm..

- Comparison of capacity outage probability tables
- Comparison of probability of loss of load at peak hour
- Comparison of LOLE for a 364-day period

The required information regarding the IEEE Test System, taken from reference [9], is presented below. It includes,

- The generating units and their reliability data (Table 3.1)

- The weekly peak loads as well as the daily peak loads given in per cent of the annual peak (2850 MW) and in per cent of the weekly peaks respectively. (Table 3.2 and Table 3.3)

Unit size (MW)	Number of units	Forced outage rate	Schedule maintenance (wks/year)
12	5	0.020	2
20	4	0.100	2
50	6	0.010	2
76	4	0.020	3
100	3	0.040	3
155	4	0.040	4
197	3	0.050	4
350	1	0.080	5
400	2	0.120	6

Table 3.1: IEEE Test System. Generator Data

Week	Peak load (%)	Week	Peak load (%)	Week	Peak load (%)	Week	Peak load (%)
1	86.20	14	75.00	27	75.50	40	72.40
2	90.00	15	72.10	28	81.60	41	74.30
3	87.80	16	80.00	29	80.10	42	74.40
4	83.40	17	75.40	30	88.00	43	80.00
5	88.00	18	83.70	31	72.20	44	88.10
6	84.10	19	87.00	32	77.60	45	88.50
7	83.20	20	88.00	33	80.00	46	90.90
8	80.60	21	85.60	34	72.90	47	94.00
9	74.00	22	81.10	35	72.60	48	89.00
10	73.70	23	90.00	36	70.50	49	94.20
11	71.50	24	88.70	37	78.00	50	97.00
12	72.70	25	89.60	38	69.50	51	100.00
13	70.40	26	86.10	39	72.40	52	95.20

Table 3.2: IEEE Test System. Weekly peak loads as per cent of annual peak

Day	Peak load (%)
Monday	93.0
Tuesday	100.0
Wednesday	98.0
Thursday	96.0
Friday	94.0
Saturday	77.0
Sunday	75.0

Table 3.3: IEEE Test System. Daily peak loads as per cent of weekly peak

Generating data, such as unit capacity, number of units, and forced outage rates, were input directly to the Is.Pgm. No maintenance of thermal units was considered. A Load Duration Curve was derived combining the per cent peak loads given in Tables 3.2 and 3.3 and entered into the program. The results obtained using the Is.Pgm. as well as the corresponding results supplied for this test system are presented in Tables 3.4 and 3.5, showing very satisfactory agreement.

3.3 INTERCONNECTED SYSTEMS PROGRAM

The basic sequential functions of the In.Pgm. may be outlined by the following steps.

- The program reads data regarding tie lines, interconnection agreements, as well as parameters to control the execution of the program.

- The program opens and reads the magnetic disk files of the power systems to be interconnected. The magnetic disk files are created in each run of the Is.Pgm.

CAPACITY ON OUTAGE (MW)	IEEE-RTS (1) CUMULATIVE PROBABILITY (2)	Is.Pgm. CUMULATIVE PROBABILITY	DIFFERENCE (%)
0	1	1	0.0000%
100	0.547601	0.547600	0.0002%
200	0.381328	0.381327	0.0003%
265	0.335566	0.335565	0.0004%
400	0.261873	0.261873	0.0002%
556	0.084578	0.084577	0.0006%
600	0.062112	0.062112	0.0008%
950	0.007491	0.007491	0.0013%
1200	0.000791	0.000791	0.0038%
1500	0.000040	0.000040	0.0000%

Notes:

1.- Reliability Test System. Figures from reference [9]
2.- Only a few states of the Outage Table are presented.

Table 3.4: Comparison of capacity outage probability tables

CASE	IEEE-RTS (1)	Is.Pgm	DIFF. (%)
Probability of loss of load at peak hour, (days/day)	0.084578	0.084577	0.0004%
LOLE for 364-day period, (days/year)	1.3689	1.37516	-0.46%

Note:

1.- Reliability Test System. Figures from reference [9]

Table 3.5: Comparison of probability of loss of load at peak hour and LOLE for 364-day period

- Optionally, it reduces the number of capacity levels in the capacity outage probability tables. This function is referred as "rounding" and is intended only for saving in computer time.

- The program determines the mode of operation between the system under study and the systems interconnected to it.

- The equivalent assisting unit models of the systems interconnected to the system under study are determined.

- The program adds the equivalent assisting units to the capacity outage probability table of the system under study.

- Finally, the program calculates the reliability indices of the system under study, combining the load characteristics with the capacity outage probability table which now includes the equivalent assisting units.

The above functions are performed by the MAIN program and the subroutines: INPF5, EQASU, FCASU, OUTAB, MULTAB, OUTIE, RELIN, and ROUND.

The MAIN program controls the overall execution of the In.Pgm. and calls the subroutines INPF5, EQASU, FCASU, MULTAB, RELIN, and ROUND. It opens and reads the files created by the Is.Pgm. MAIN also determines the mode of operation between the system selected for study and the power systems interconnected to it, and controls the logics of the program e.g., by calling the appropiate subroutines in order to simulate the appropiate mode of operation of the power systems. The last function of MAIN is to print the annual summary of reliability indices.

The In.Pgm. is capable of simulating the following modes of operation between power systems,

- The system under study supplying capacity assistance to a neighboring system

- The system under study receiving firm capacity assistance from a neighboring system

- The system under study receiving capacity assistance from a neighboring system, subject to available reserves and random outages in the assisting system, and

- The system under study receiving both firm capacity assistance and capacity assistance subject to availability in the assisting system.

Subroutine INPF5 (INPut File 5) reads and checks the input data file which contains the information on tie line characteristics and firm purchase capacities.

Subroutine EQASU (EQuivalent ASsisting Unit) calculates the equivalent assisting unit for the case of capacity assistance subject to reserves and random outages in the assisting system. EQASU calls the subroutines OUTAB and OUTIE.

Subroutine FCASU (Firm Capacity ASsisting Unit) calculates the equivalent assisting unit for the case of firm capacity assistance. FCASU calls subroutine OUTAB.

Subroutine OUTAB (OUtage TABle) derives the tie-line capacity outage probability table, which represents all possible states of the tie lines interconnecting two power systems.

Subroutine OUTIE (OUtage table - TIE table) combines an equivalent assisting unit model with a tie-line capacity outage probability table. It implements the probability array method outlined in section 2.3.3.

Subroutine MULTAB (MULti-state unit outage TABle) "adds" the equivalent assisting unit model to the capacity outage probability table of the system under study. It implements the recursive method presented at the end of section 2.2.2.

Subroutine RELIN (RELiability INdices) calculates the LOLE and the LOEE in each period of the year. The same subroutine is used in the Is.Pgm.

Subroutine ROUND is used optionally to round the capacity outage tables to a specified capacity increment.

Fig. 3.7 presents a flow chart of the MAIN program showing its major functions as well as the sequence in which the subroutines are called. Further details regarding the respective algorithms are presented in Subsections 3.3.1 - 3.3.8 below.

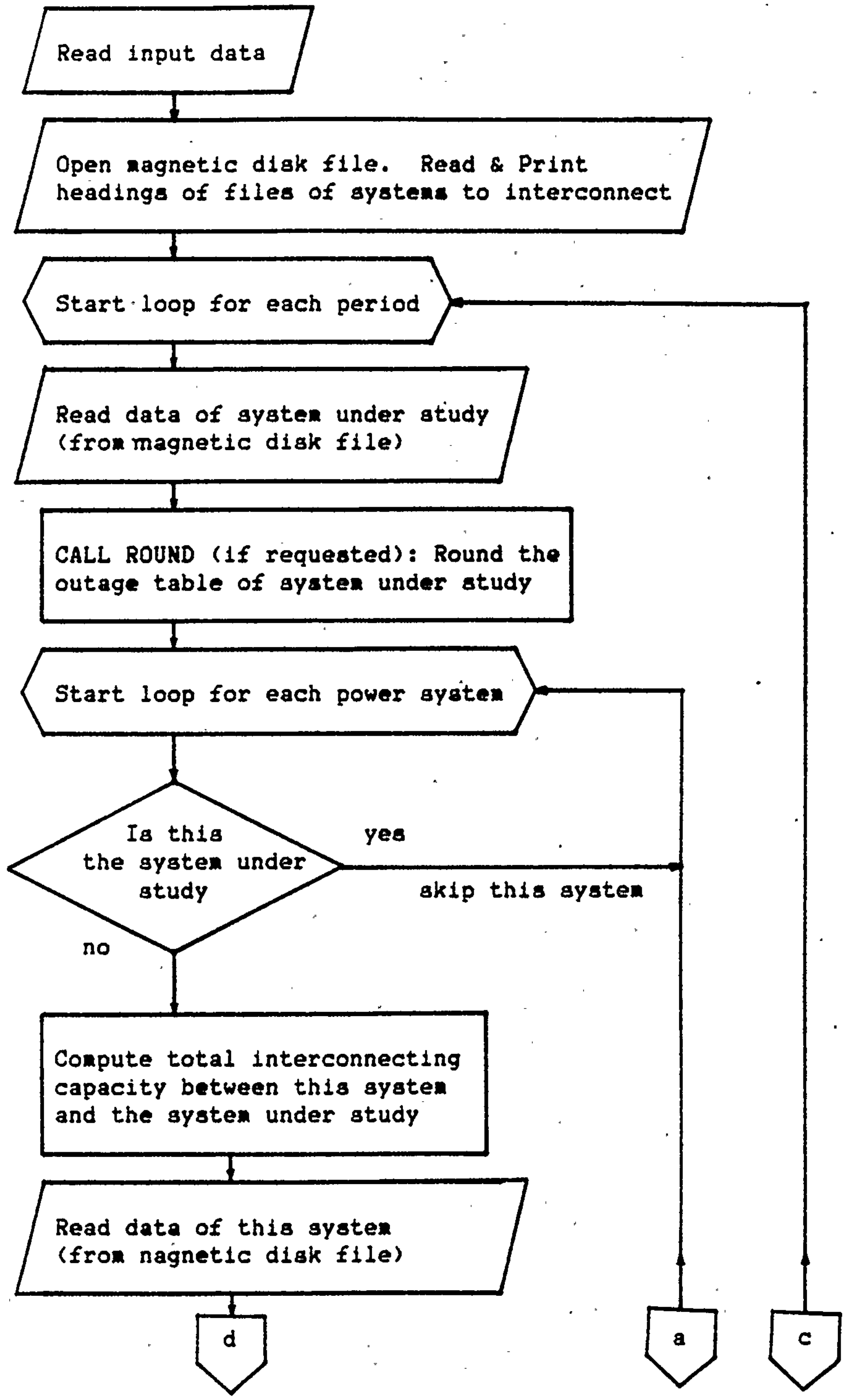


Figure 3.7: In.Pgm. Flowchart of MAIN program

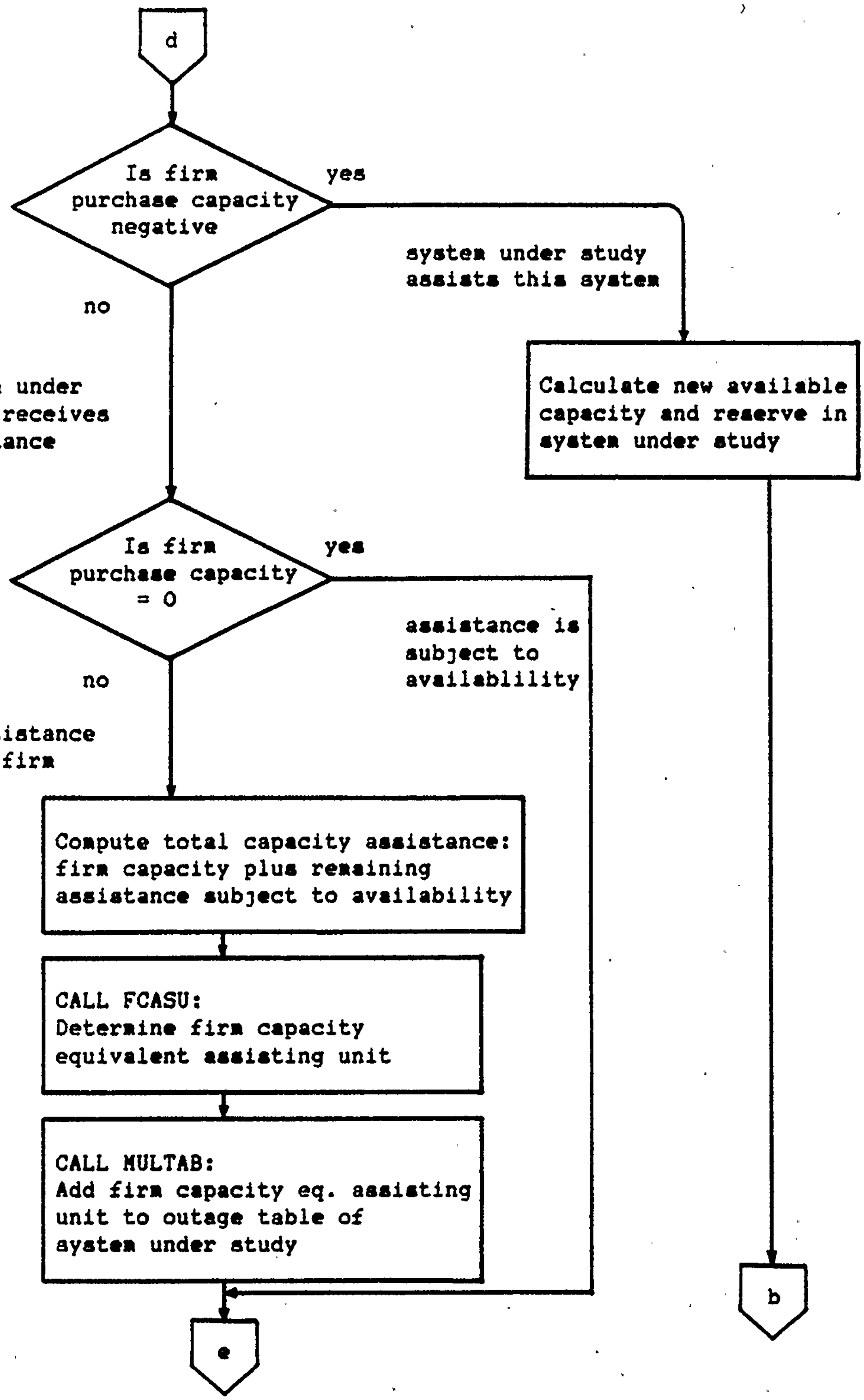


Figure 3.7 (cont'd): In.Pgm. Flowchart of MAIN program

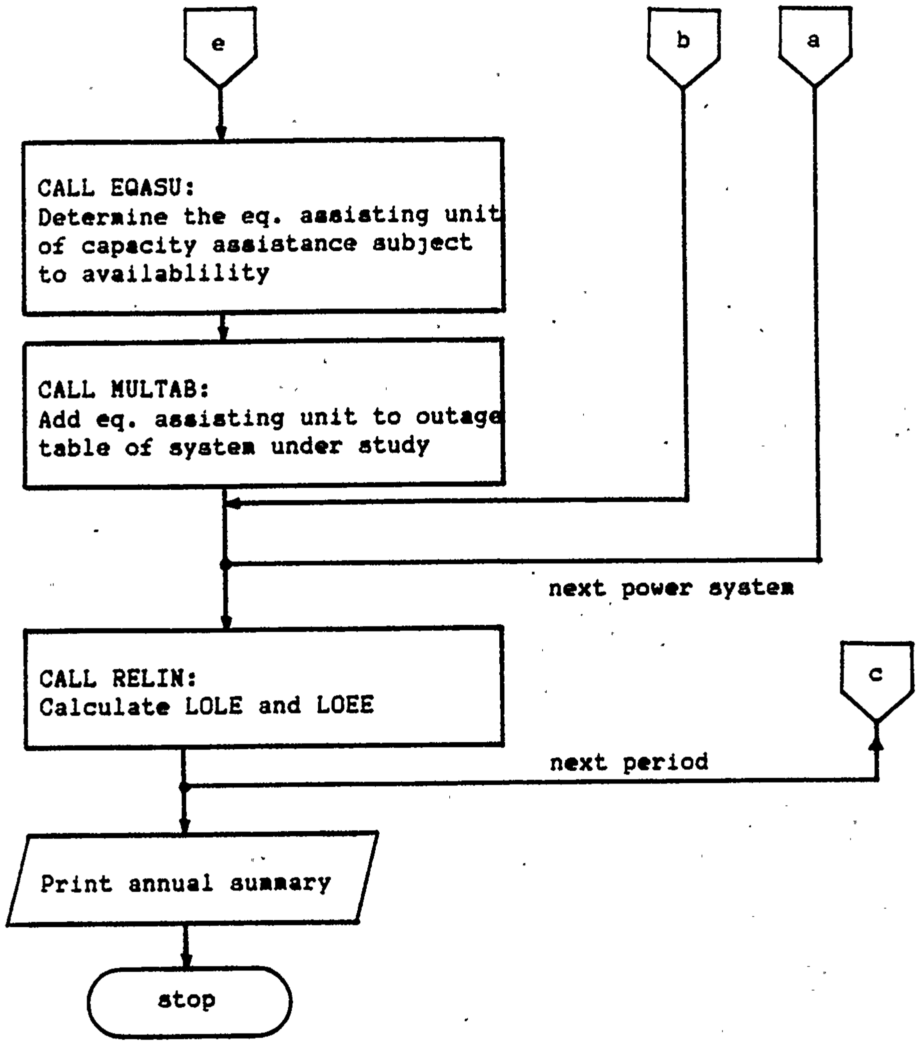


Figure 3.7 (cont'd): In.Pgm. Flowchart of MAIN program

3.3.1 Input data

The following list summarizes the input data to the In.Pgm.

General data,

- Description of the study
- Name of power systems to be interconnected
- Data file device number of magnetic disk files
- Power system to calculate reliability indices (Referred as the system under study)

Tie lines characteristics,

- "From" system number, "To" system number
- Tie line capacity (MW)
- Forced Outage Rate (per unit)

Firm capacity purchases,

- "From" system number (to system under study)
- Firm purchase capacity for each period (MW). A negative entry indicates a sale of capacity.

Options,

- Maximum allowed number of capacity levels in the capacity outage probability table (max. 5000)

- Option to skip calculation of new capacity levels
- Minimum probability to end outage table (per unit)
- Minimum allowed capacity step for the outage table
- Increment for capacity table rounding (MW)
- Option to print outage table
- Options to request calculation of LOLE and/or LOEE
- Option to request detailed output

The In.Pgm. also reads data from magnetic disk files. Such files are created in each run of the Is.Pgm. The information read from these files is,

General,

- Description of the study
- Number of periods per year
- Year of study
- Annual peak demand

For every period of the year,

- Period peak demand
- Period available capacity. (Installed capacity derated to account for maintenance of thermal plants)
- Period length. (Number of hours in the period)
- Load Duration Curve, modified after hydro-schedule

- Capacity outage probability table

3.3.2 Capacity outage table rounding

In a practical power system containing a large number of units of different capacities, the outage table will contain several hundred possible discrete capacity outage levels. This number can be reduced by so-called rounding, i.e. by choosing a set of fewer evenly spaced capacity levels. The final rounded table contains capacity outage magnitudes that are multiples of the rounding increment, which is specified by the user. The number of capacity levels decreases as the rounding increment increases, with a corresponding decrease in accuracy.

The rounding of capacity outage probability tables in the In.Pgm. is intended merely to save computer time, therefore, the use of this feature is optional.

The method used for rounding (reference [9]) consists of the calculation of probabilities, for the required capacity states, by scaling and adding the probabilities of the existing states adjacent to the required state. Fig. 3.8 illustrates this method graphically. The general expressions for the rounding process are:

$$P(Cj) = \frac{Ck - Ci}{Ck - Cj} P(Ci)$$

$$P(Ck) = \frac{Ci - Cj}{Ck - Cj} P(Ci)$$

for all states "i" falling between the required rounding states "j" and "k".

3.3.3 Mode of operation and total capacity assistance

The In.Pgm. determines the mode of operation of interconnected power systems by checking the value of the firm purchase capacity in every period of the year. If the firm purchase capacity between a power system and the system under study is a negative quantity, the program takes this as a sale of capacity, i.e., the system under

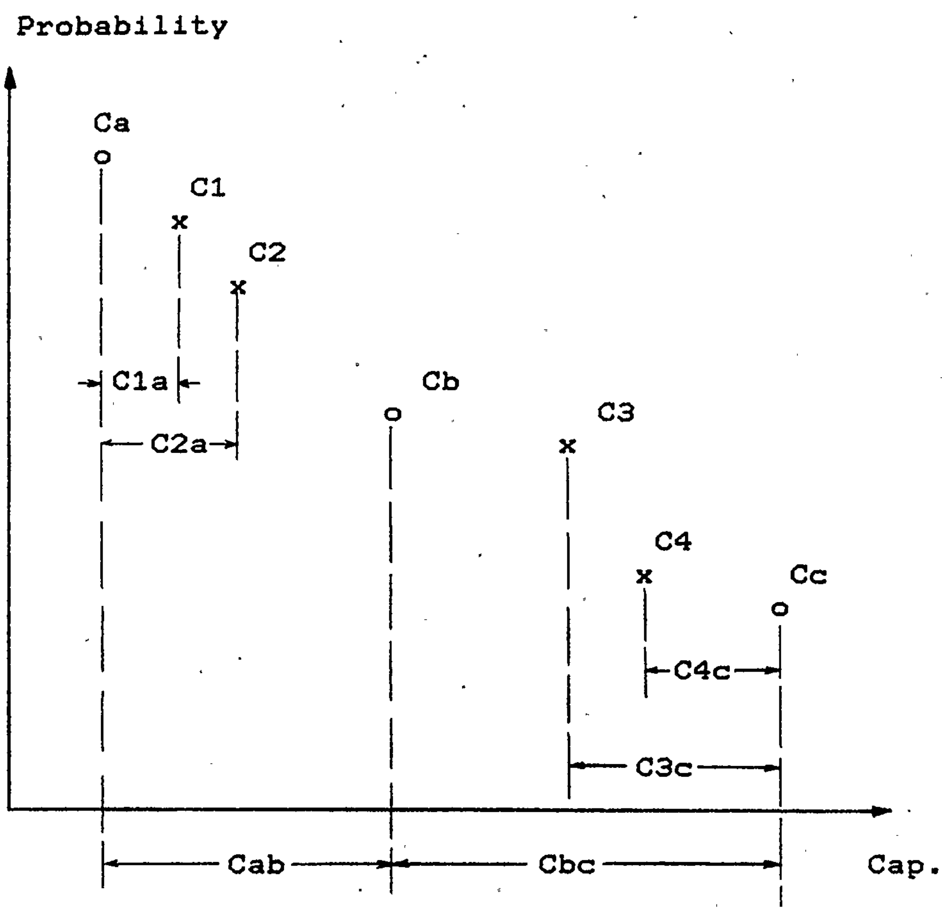


Figure 3.8: Probability of a required rounding state.

Legend. o : Required rounding state
x : Existing capacity state

Ca, Cb, Cc : capacity of required states a, b, c.

C1 - C4 : capacity of existing states 1 - 4.

$C_{ij} = C_j - C_i$: Capacity difference between states "i" and "j".

The probability of the required rounding state "b" is :

$$P(Cb) = \frac{C1a}{Cab}P(C1) + \frac{C2a}{Cab}P(C2) + \frac{C3c}{Cbc}P(C3) + \frac{C4c}{Cbc}P(C4)$$

study assists the neighboring system with a capacity equal to the absolute value of the firm purchase capacity. In this case the program reduces the reserve in the system under study by the amount of the capacity sale. It also checks that the capacity sale is smaller than the total interconnecting capacity between the power systems. If it is not, it sets the capacity sale equal to the total tie-line(s) capacity and prints a warning message.

If the firm purchase capacity is equal to zero, the program considers the system under study as receiving capacity assistance subject to available reserve and random outages in the assisting system. In this case the total capacity assistance that the system under study can receive from the assisting system in each period, is equal to the reserve in the assisting system, (in the same period), or equal to the total tie-line(s) capacity, whichever is less.

If the firm purchase capacity is larger than zero, the program simulates the firm purchase capacity as fully reliable capacity assistance at the sending end of the tie-line(s). If the reserve in the assisting system and the capacity of the tie-line(s) are larger than the amount of firm capacity, then the program considers that there is capacity assistance, in addition to the firm capacity assistance, which is subject to available reserve and random outages in the assisting system. In this case, the total capacity assistance, in each period, is equal to the firm capacity assistance plus the additional assistance subject to availability.

Table 3.6 summarizes the modes of operation that can be modelled in the In.Pgm. and indicates the total assisting capacity resulting in each case.

Firm purchase capacity	Mode of operation	Total assisting capacity
< 0	System under study assists neighboring power system	|Firm purchase cap.| or Total tie capacity, whichever is less
= 0	System under study gets assistance subject to availability	Total tie capacity or Reserve whichever is less
> 0	System under study gets firm cap. assistance	Firm purchase cap.
	System under study gets firm cap. assistance plus additional cap. subject to availability	Total tie capacity or Reserve whichever is less

Table 3.6: Summary of modes of operation and total assisting capacity

3.3.4 Firm capacity equivalent assisting unit

The In.Pgm. develops a firm capacity equivalent assisting unit for every period of the year in which the system under study receives firm capacity assistance. The program implements the method outlined in Chapter 2, section 2.3.5.

This task is carried out by the subroutine FCASU (Firm Capacity ASsisting Unit), and involves the following steps,

- Subroutine FCASU calls subroutine OUTAB to build the capacity outage probability table of the tie-line(s) that interconnect the system under study and the assisting system. This table represents all possible outage states of the tie-lines between both systems.

- The subroutine takes the firm purchase capacity as fully reliable capacity assistance at the sending end of the tie-line(s), i.e., it assigns an outage probability equal zero to the firm purchase capacity.

- The subroutine combines the tie-line(s) capacity outage probability table with the firm purchase capacity at the sending end of the tie-line(s). The resultant outage table represents the firm capacity at the receiving end of the tie-lines. The effects of tie-line capacity, tie-line forced outage rates, and number of tie-lines, are considered. This table is the equivalent assisting unit model of the firm purchase capacity.

Fig. 3.9 shows the flow chart of subroutine FCASU.

Subroutine OUTAB is the same subroutine used in the Is.Pgm. to build the capacity outage probability table of the generating system. In this case however, OUTAB "adds" one tie-line at a time, rather than generating units, to build the tie-line(s) capacity outage probability table.

3.3.5 Equivalent assisting unit of capacity assistance subject to available reserve and random outages

The In.Pgm. develops an equivalent assisting unit of capacity assistance subject to available reserve and random outages in the assisting system for every period of the year in which the interconnected power systems operate in such a mode. The development of the equivalent unit is

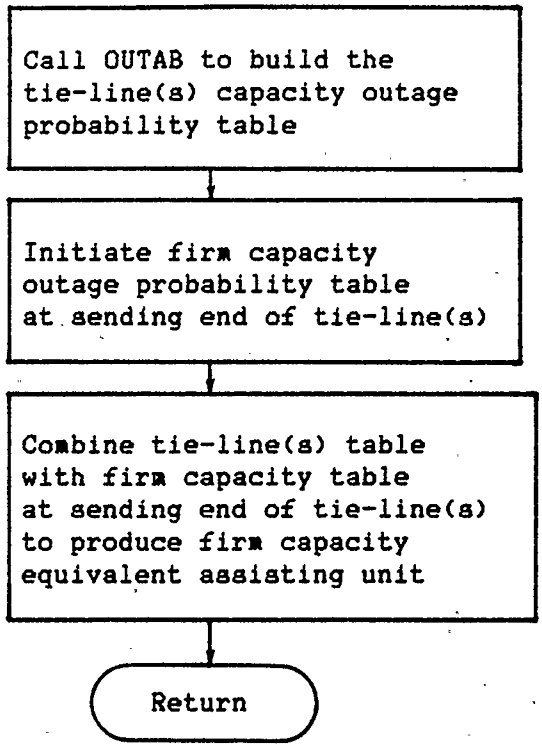


Figure 3.9: Flow chart of subroutine FCASU

carried out using the method described in Chapter 2, sections 2.3.1 to 2.3.4.

Subroutine EQASU (EQuivalent ASsisting Unit) develops this equivalent assisting unit, which involves the following steps,

- The subroutine determines the capacity assistance probability table, constrained by reserves in the assisting system.

- It calculates the total interconnecting capacity between the system under study and the assisting system.

- If applicable, it restrains the assistance table to the interconnecting capacity.

- It calls subroutine OUTAB to build the tie-line(s) capacity outage probability table.

- It converts the constrained capacity assistance table to a capacity outage probability table. This table represents the equivalent assisting unit at the sending end of the tie-line(s).

- It calls subroutine OUTIE to combine the tie-line(s) outage table with the equivalent assisting unit at the sending end of the tie-line(s). The resultant table is the equivalent assisting unit model of the assisting system. This equivalent unit considers the available reserve and random outages on the assisting system as well as the tie-line(s) capacity, forced outage rates, and number of tie-lines.

Fig. 3.10 shows the flow chart of subroutine EQASU.

Subroutine OUTIE combines the above mentioned tables using the probability array method presented in section 2.3.3.

3.3.6 Addition of equivalent assisting units to the capacity outage probability table

Once the In.Pgm. has developed an equivalent assisting unit, whether for firm capacity or for capacity assistance subject to availability, it is necessary to "add" the equivalent unit (or units) to the outage table of the system under study. This function is performed by the

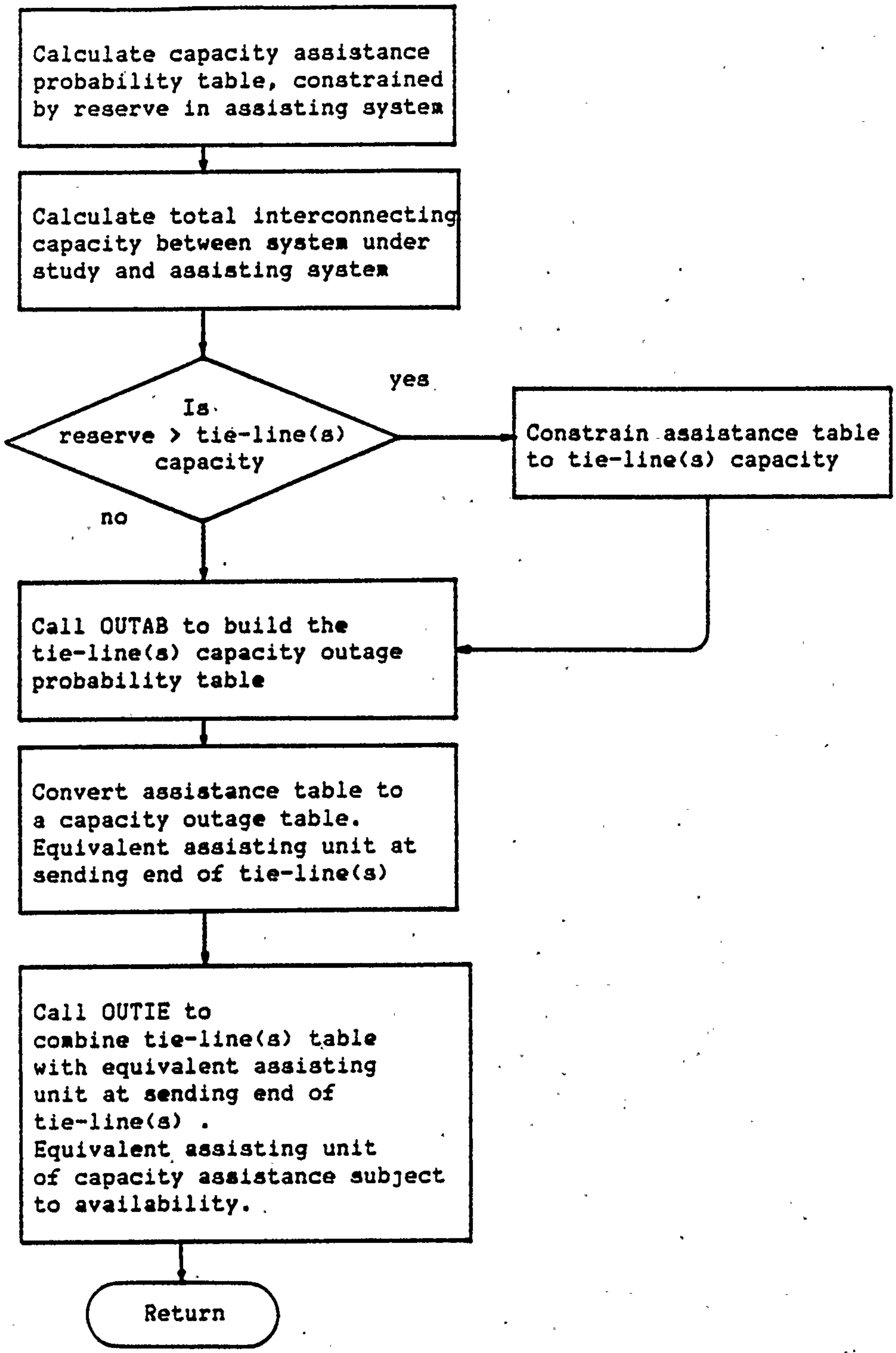


Figure 3.10: Flow chart of subroutine EQASU

subroutine MULTAB, which implements the method presented in Chapter 2, at the end of section 2.2.2.

The subroutine can be described as being composed of three major sections. In the first section, the probability of outage of the existing capacity levels in the table are recalculated each time an equivalent unit is added. In the second section, the algorithm determines new outage capacity levels and calculates their corresponding probability of occurrence. The new levels are added to the bottom of the existing table. In the last section, after all equivalent units are added the algorithm sorts the table, arranging the outage capacity levels in ascending order.

To limit the number of capacity levels in the table, the subroutine has three built-in features.

a) If, when adding a unit, a new capacity level results closer to an existing capacity level than a user-specified capacity step, then the new level is simply disregarded.

b) If, after adding several units, the probability calculated for a new capacity level is smaller than a user-specified value, the table is considered completed (typical values to end the table are 1.0 E-8 to 1.0 E-6).

c) When the number of capacity levels in the original capacity outage table is large, the addition of a multi-state unit will result in very few new capacity levels added to the table. In this case, the user can choose not to calculate new levels and only recalculate the probabilities of the existing capacity levels. This option results in saving of computer time.

The subroutine also has a safety feature that stops execution and prints an error message when the number of capacity levels surpasses a user-specified maximum value.

Because MULTAB implements the recursive method for multi-state units of section 2.2.2, which is a more general case of the method used in the Is.Pgm. to build the capacity outage probability table, a flowchart of MULTAB would look the same as the flowchart of OUTAB. Therefore, for all intents and purposes, the flow chart of subroutine MULTAB is shown in section 3.2.4, figure 3.5.

3.3.7 Reliability indices

After the equivalent assisting units have been added to the capacity outage probability table of the system under study, the calculation of reliability indices in the system under study can proceed as if it were an isolated system. For this reason, the calculation of LOLE and LOEE in each period of the year is carried-out by subroutine RELIN, which is the same subroutine used in the Is.Pgm. Refer to section 3.2.5 for explanations of this subroutine. Figure 3.6 presents a flowchart of subroutine RELIN.

3.3.8 Reporting capabilities

The In.Pgm. produces a report which contains the following sections,

- A reproduction of the input data file
- Summary of magnetic disk files opened in the run
- Rounded capacity outage table of system under study
- Interconnection agreements

- Capacity outage table of system under study after addition of equivalent assisting units
- Calculation of reliability indices
- Summary of annual reliability indices

The size of the report depends on the options and features used in the execution of the program. The reproduction of the input datafile, the summary of magnetic disk files opened in the run, the capacity outage table after addition of equivalent units, and the summary of annual reliability indices have a fixed format and they are always printed. The report on interconnection agreements depends on the mode of operation of interconnected systems. The rounded capacity outage table is printed only if this feature is used. The calculation of reliability indices can be printed in detail or summary form, depending on the option selected by the user.

The reproduction of the input datafile is intended to allow the user to verify the input data after the execution of the program.

The summary of magnetic disk files opened in the run serves similar purpose, i.e., verification that the proper files were used in the execution of the program. This summary contains the following information for each file opened,

- The file device number and name of the power system
- The description of the case study, entered in the Is.Pgm. that created this file
- The number of periods per year, the year of study, and the annual peak (read from the file)

The number of periods per year as well as year of study, read from all the files, are compared to ensure compatibility of files. If they do not match, an error message is printed and execution is terminated.

The rounded outage probability table is printed as a matrix of 8 columns and as many rows as necessary to cover all capacity levels together with their corresponding probabilities.

The section about interconnection agreements is printed in every period of the year and a number of times equal to the number of power systems interconnected to the system under study. This section contains a fixed portion, i.e., information which is printed regardless of the mode of operation, and a variable portion that depends on the mode of operation.

The fixed portion contains the following information.

- A heading with the names of the system under study and the system interconnected to it
- The total interconnecting capacity between both systems
- A summary of the main characteristics of the system interconnected to the system under study. The sumary includes,
  - total capacity available in thermal plants (derated to account for maintenance)
  - hydroelectric capacity scheduled in the period
  - total available capacity (thermal + hydro)
  - period peak demand
  - reserve at peak hour, and
  - period length.

If the system under study assists the neighboring system, the variable portion of the report on interconnection agreements contains,

- The mode of operation, which reads "SYSTEM UNDER STUDY SUPPLIES ####. MW OF CAPACITY

ASSISTANCE"

- The original available capacity including assistance from other systems (if any)

- The new reserve capacity

If the system under study receives firm capacity assistance, the variable portion of the report on interconnection agreements contains,

- The mode of operation, which reads "SYSTEM UNDER STUDY PURCHASES ####. MW OF FIRM CAPACITY"

- A list of the tie-lines interconnecting the system under study and the assisting system, together with their capacities and forced outage rates

- The tie-line(s) outage probability table

- The firm capacity equivalent assisting unit

If the system under study receives capacity assistance subject to availability, the variable portion of the report on interconnection agreements contains,

- The mode of operation, which reads "SYSTEM UNDER STUDY MAY RECEIVE UP TO ####. MW FROM SYSTEM NO. # SUBJECT TO AVAILABILITY"

- A list of the tie-lines interconnecting the system under study and the assisting system, together with their capacities and forced outage rates

- The tie-line(s) outage probability table

- The equivalent assisting unit model of the assistance capacity subject to availability

The capacity outage table of the system under study, after addition of equivalent assisting units, is printed in the same format as the rounded table, i.e., a matrix of 8 columns and as many rows as necessary to cover all capacity levels.

The print-out of reliability indices as well as the print-out of annual summary are identical to the Is.Pgm. Refer to section 3.2.6. for a description of these sections of the output report.

3.3.9 Tests

The IEEE presented a study in which two identical Test Systems were interconnected through a completely reliable tie-line of variable capacity. (Description of the IEEE Test System is included in section 3.2.6). The same study was conducted using the Interconnected Program and the results obtained were compared to the IEEE's results, see Table 3.7.

The largest percentage difference between the LOLE calculated by the In.Pgm. and the LOLE released by the IEEE was 0.72%. The performance of the In.Pgm. was therefore considered satisfactory.

TIE-LINE CAPACITY (MW)	IEEE-RTS (1) LOLE (d/y)	-INTERCONNECTED LOLE (d/y)	PROGRAM-- DIFFERENCE (%)
0	1.369	1.378 (2)	-0.657%
100	0.750	0.752	-0.267%
200	0.463	0.466	-0.648%
300	0.341	0.343	-0.587%
400	0.293	0.294	-0.341%
500	0.277	0.275	0.722%

Notes:

1.- Reliability Test System. Figures from reference [9]
2.- Calculated by the Is.Pgm.

Table 3.7: Comparison of LOLE calculated by the In.Pgm. and by the IEEE on its test system

Chapter IV

RELIABILITY OF SUPPLY IN ALBERTA

4.1 INTRODUCTION

In this Chapter, the computer model is used to investigate the reliability of supply and the static capacity requirements of Alberta under specific operating conditions with and without electrical interconnections with B.C. and Sask. Selected results are presented and discussed.

Information regarding the British Columbia and Saskatchewan electric systems was obtained from the major utilities in those provinces. The characteristics of the generating units in Alberta were obtained from reference [3]. The load characteristics in the province was obtained from records of the hourly peak demands in the past 5 years; from these records, monthly load duration curves were derived (using another computer program), and subsequently adjusted to reflect the load factor forecasted for the year 1992. No further changes were made on the LDC's, so that the shape of the curves derived for the year 1992 was assumed constant througout the entire study period. The complete set of data used in this study is presented in the appendix.

The period selected for study covers the years 1992 to 1996 inclusive. The reasons for selecting this particular period are outlined below.

Three new generating units are presently approved for commissioning in the 1989 - 1991 time frame in order to meet the growth of electric energy demand in Alberta. Although the commissioning dates of these units have been the matter of several reviews and they might be rescheduled in the future, this study assumes that these generating units will be operating by their respective currently-scheduled commissioning dates (*).

(*)

Commissioning date of Sheerness Unit No.2: October 1990

Commissioning date of Genesee Unit No. 1: October 1991

Commissioning date of Genesee Unit No. 2: October 1989

The selected forecast of load growth in Alberta suggests that additional generating facilities might be needed in the 1992 - 1996 time period. This fact makes the study period interesting because the need of new unit(s) can be determined for different modes of operation of the interconnected power systems.

Certain information regarding the power systems in the neighboring provinces is not available for the period beyond 1996.

The study period (1992 - 1996) is divided into 5 climatic years and calculation of reliability is carried out for every climatic year. Each year is subdivided into 12 monthly periods, beginning with October and extending up-to and including the following September. New generating additions in Alberta are normally scheduled to start operation in October, so that the new unit is available during the annual peak which usually occurs in December or January. This fact makes a climatic year more appropiate than a calendar year for reliability evaluation, because new generation additions will always take place at the beginning of the year. The use of climatic years is a standard practice in Alberta.

The operating conditions, simulated in this study, are the following.

A. Alberta isolated.

B. Alberta interconnected only to B.C.

B1. Assistance from B.C. 300 MW firm.
No additional assistance.

B2. Assistance from B.C. 600 MW subject to availability.

B3. Assistance from B.C. 800 MW subject to availability.

C. Alberta receives capacity assistance from B.C. and Sask.

C1. Assistance from B.C. 300 MW firm.
Assistance from Sask. 100 MW subject to availability.

C2. Assistance from B.C. 300 MW firm.
Assistance from Sask. 100 MW firm.

C3. Assistance from B.C. 600 MW firm.
Assistance from Sask. 100 MW subject to availability.

C4. Assistance from B.C. 800 MW.firm
Assistance from Sask. 100 MW subject to

availability.

D. Alberta assists Sask. B.C. assists Alberta.

D1. Assistance from B.C. 300 MW firm.

Assistance to Sask. 100 MW.

D2. Assistance from B.C. 600 MW firm.

Assistance to Sask. 100 MW.

D3. Assistance from B.C. 800 MW firm.

Assistance to Sask. 100 MW.

E. Alberta assists B.C. and Sask.

E1. Assistance to B.C. 300 MW.

Assistance to Sask. 100 MW.

F. Alberta assists B.C. Sask. assists ALberta.

F1. Assistance to B.C. 300 MW.

Assistance from Sask. 100 MW subject to availability.

Case A, Alberta isolated, is intended to set the basis for comparisons in order to evaluate the benefits of different interconnection arrangements between the three power systems.

Case B1, in which Alberta is interconnected only to

B.C. and receives 300 MW of firm capacity with no additional assistance, provides a second basis for comparison. This case represents the way in which previous evaluations of the reliability of supply in Alberta have been conducted (reference [4]). In this case comparisons and assesments can be extended using the new approach presented in this study.

Cases C and D, in which B.C. supplies capacity assistance to Alberta, are the cases considered most likely to occur. This is because B.C. has a very large installed capacity relative to its load, and the associated reserves are expected to remain large beyond the study period.

Cases E and F, in which Alberta supplies B.C. with assistance capacity, are included in this study to cover the possibility of B.C. exporting large amounts of capacity to the Western United States, and continuous support of capacity from Alberta is desirabe.

To evaluate the impact of interconnections on the development of the Alberta electric system, the reliability criteria for static capacity requirements adopted in this study states that the power system should operate at a maximum risk level (or loss of load expectation) of 0.2 hours/year, calculated on the average hourly loads of the system for an entire year. This criteria is applied to every case in order to determine the need for new generating facilities in Alberta.

4.2 ALBERTA SYSTEM ISOLATED

In order to evaluate the impact of interconnections on the reliability of supply in Alberta, it is necessary to establish a basis for comparisons. In this study, the basis for comparisons chosen is the set of reliability indices obtained when the Alberta electric system operates totaly isolated from any neighboring power systems.

Table 4.1 presents the results obtained for this case. In the table, the second and third columns show the calculated LOLE and LOEE respectively. The fourth column, which results from the application of the reliability criteria, shows that the Alberta system under isolated operating conditions needs additional capacity in the year 1992.

YEAR	LOLE hrs/year	LOEE MWh	ADDITIONAL CAPACITY REQUIRED
1992	7.66	962.5	Yes
1993	10.04	1249.2	Yes
1994	14.49	1799.9	Yes
1995	21.88	2835.6	Yes
1996	26.03	3347.6	Yes

Table 4.1: CASE A
Alberta isolated.

YEAR	LOLE hrs/year	LOEE MWh	ADDITIONAL CAPACITY REQUIRED
1992	1.24	181.6	Yes
1993	1.67	246.5	Yes
1994	2.52	379.5	Yes
1995	3.98	618.3	Yes
1996	4.75	768.3	Yes

Table 4.2: CASE B1
Assistance from B.C. 300 MW firm. No additional assistance.

4.3 ALBERTA INTERCONNECTED TO BRITISH COLUMBIA

CASE B1. Assistance from B.C. 300 MW firm.
No additional assistance.

This case represents the way in which previous evaluations of the reliability of supply in Alberta have been conducted (reference [4]). Table 4.2 presents the results obtained under this operating condition. In this case, Alberta needs new generating facilities in 1992.

CASE B2. Assistance from B.C. 600 MW
subject to availability.

In this case, the capacity assistance from B.C. is allowed to be as much as 600 MW, but the assistance is subject to random outages in that power system. This is a very probable scenario because the limit of capacity transfer of the transmission line is well above 600 MW, and so far there is no sign of a firm purchase capacity agreement . Table 4.3 presents the results obtained under this operating condition. In this case, new generating facilities are marginally needed in 1992.

YEAR	LOLE hrs/year	LOEE MWh	ADDITIONAL CAPACITY REQUIRED
1992	0.227	30.4	Yes, marginal
1993	0.31	42.7	Yes
1994	0.47	67.7	Yes
1995	0.75	112.6	Yes
1996	0.94	141.6	Yes

Table 4.3: CASE B2
Assistance from B.C. 600 MW subject to availability.

YEAR	LOLE hrs/year	LOEE MWh	ADDITIONAL CAPACITY REQUIRED
1992	0.104	12.2	No
1993	0.144	18.4	No
1994	0.217	29.6	Yes, marginal
1995	0.35	49.4	Yes
1996	0.43	63	Yes

Table 4.4: CASE B3
Assistance from B.C. 800 MW subject to availability.

CASE B3. Assistance from B.C. 800 MW subject to availability.

In this case, the capacity assistance from B.C. is allowed to be as much as 800 MW, but the assistance is again subject to random outages in that power system. This case is not likely to ocur in reality. Although the tie-line could be loaded to 800 MW, the general feeling is that the Alberta electric system would become very much dependent on the assistance from B.C. and a failure of the tie-line would create serious difficulties within Alberta. Table 4.4 presents the results obtained under this operating condition. In this case, Alberta does not need new generating facilities until 1994.

Comparisons of the results obtained in cases A, B1, B2, and B3 are presented in Figure 4.1 and Figure 4.2. The graphs in these figures show the LOLE and LOEE calculated in every year for the different cases. It becomes immediately clear, from these figures, that as the capacity assistance from B.C. is increased, the reliability indices in the Alberta electric system decrease substantially.

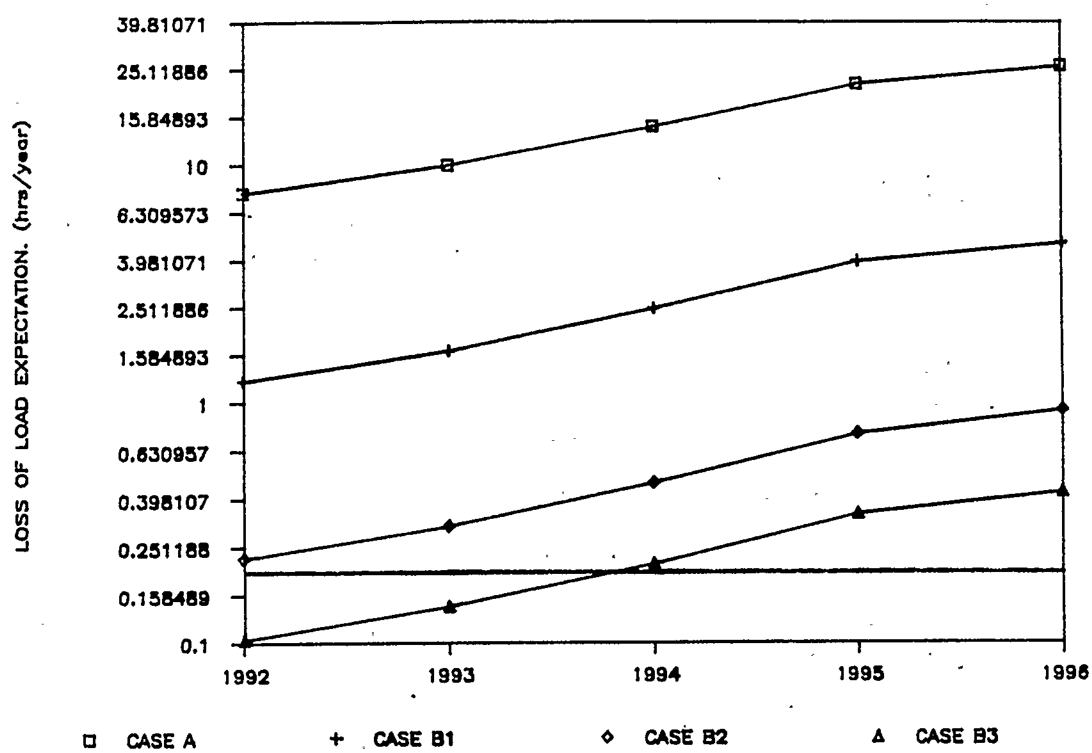


Figure 4.1: Loss of Load Expectation.

Alberta isolated vs Alberta interconnected only to B.C.

where:

CASE A. Alberta isolated.

CASE B1. Assistance from B.C. 300 MW firm.

No additional assistance.

CASE B2. Assistance from B.C. 600 MW subject to availability.

CASE B3. Assistance from B.C. 800 MW subject to availability.

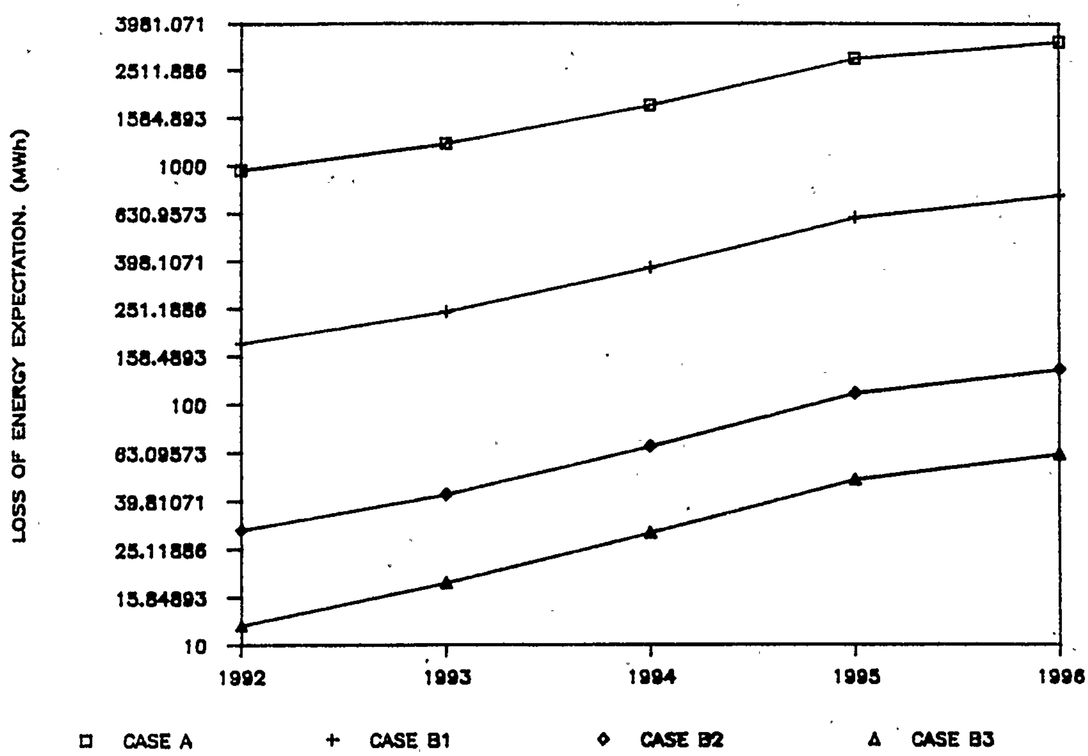


Figure 4.2: Loss of Energy Expectation.

Alberta isolated vs Alberta interconnected only to B.C.

where:

CASE A. Alberta isolated.

CASE B1. Assistance from B.C. 300 MW firm.

No additional assistance.

CASE B2. Assistance from B.C. 600 MW subject to availability.

CASE B3. Assistance from B.C. 800 MW subject to availability.

The slight increase of LOLE from year to year is due to the load growth in Alberta. Load growth in B.C. does not affect the LOLE in Alberta because the reserves in that system are substantially larger than the amount of capacity assistance, which is limited only by the tie-line capacity. Table 4.5 shows the reserves in the B.C. electric system for each month in the study period.

The smoothness of the curves is a result of neither additions nor retirements of generating units taking place during the study period. The horizontal line in Fig.4.1 marks the LOLE of 0.2 hrs/year used to determine the need for new generating facilities. Below this line Alberta does not need additional capacity.

The fact that the reserves in the B.C. electric system are very large, relative to the amount of capacity assistance, and in general the generating system in that province is very reliable (*), produces another interesting result. The equivalent assisting unit model of capacity assistance subject to available reserve and

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(*): The Forced Outage Rates of the majority of the generating units in B.C. are equal to or lower than 2%.

CLIMATIC YEAR					
	RESERVE (MW)				
MONTH	1992	1993	1994	1995	1996
OCT	3789	3701	3541	3416	3255
NOV	3219	3120	2946	2811	2637
DEC	2939	2849	2669	2529	2349
JAN	3219	3143	2969	2835	2661
FEB	3269	3203	3031	2897	2725
MAR	3859	3793	3635	3512	3354
APR	4329	4192	4043	3927	3778
MAY	4619	4485	4343	4232	4090
JUN	4659	4522	4381	4271	4129
JUL	4919	4786	4651	4546	4410
AUG	4859	4728	4592	4485	4349
SEP	4459	4316	4170	4056	3910

Table 4.5: Reserve capacity in the B.C. electric system.

random outages in B.C. becomes equal to a firm capacity equivalent assisting unit, i.e., the assistance capacity becomes fully reliable at the sending end of the tie-line. This situation happens for those periods of the year in which the reserve is very large compared to the amount of assistance capacity, and has been identified in cases B2 and B3 as shown in Table 4.6

YEAR	CASE B2 600 MW subject to availability	CASE B3 800 MW subject to availability
1992	(none)	December
1993	December	December
1994	December	November to February
1995	November to January	October to March
1996	October to February	October to April

Table 4.6: Periods in which equivalent assisting unit subject to availability is different from firm capacity equivalent assisting unit

To explain this situation, let us consider CASE B2 in which Alberta receives 600 MW of assistance capacity, subject to available reserve and random outages in B.C. For the first period (October) of the year 1992, the capacity outage probability results are shown in Table 4.7:

STATE	CAPACITY ON OUTAGE. (MW)	CUMULATIVE PROBABILITY	CAPACITY ASSISTANCE (MW)
1	0	1.00000000	3358
2	5	.94150591	3353
3	8	.93914258	3350
4	13	.93319821	3345
5	17	.93296015	3341
.	.	.	.
.	.	.	.
.	.	.	.
790	2224	.00000179	1134
791	2227	.00000176	1131
792	2230	.00000170	1128

Table 4.7: Capacity outage probability table and level of assistance of the B.C. system in October 1992

The outage table contains 792 states (only the initial and final states are shown). Also, the level of capacity assistance which results when the capacity on outage is subtracted from the reserve, is shown in the fourth column of Table 4.7. Note that the reserve in this case is 3358 MW instead of the 3789 Mw shown in Table 4.5. This difference occurs because the installed capacity in October 1992 has been derated according to the schedule of maintenance of generating units, developed for that year.

The last state calculated by the program was state No. 792, with 2230 MW of capacity on outage having a per-unit probability of occurrence of 0.00000170. The program did not calculate states with capacity on outage larger than 2230 MW because their probabilities were smaller than a specified minimum probability. (The capacity outage subroutine has this feature in order to avoid the calculations of outage states with extremely small probability. In this case the minimum probability was set to 10 to the power -6).

Then, in the simulation, any level of capacity on outage larger than 2230 MW has a probability of occurrence equal to zero. Let us assume that the next additional state in the table, state No 793, has capacity on outage of 2231 MW with probability of occurrence equal to zero. The level of assistance capacity would be: 3358 - 2231 = 1127 MW. This means that any capacity assistance of 1127 MW or less would be fully reliable because the probability of an outage resulting in a capacity assistance equal to or less than 2231 MW would be equal to zero.

In October 1992, under CASE B1, the capacity assistance of 600 MW becomes fully reliable at the sending end of the tie-line, which makes it similar to a firm capacity agreement. This same situation takes place in all the other periods of 1992 for the same case, as well as in some periods in following years. However, this situation does not occur in the periods shown in Table 4.6, for which the equivalent assisting unit model of capacity assistance subject to availability becomes a multi-state generating unit.

Let us consider CASE B3, in which Alberta receives 800 MW of capacity assistance subject to available reserve and random outages in B.C. In December 1996, the reserve in B.C. is 2349 MW (derated to account for scheduled maintenance) and the equivalent assisting unit, calculated at the receiving end of the tie-line, is a multi-state generating unit of 340 outage states. Figure 4.3 shows some outage states of the equivalent unit, copied from the actual output produced by the program.

Examination of this table brings out another

BRITISH COLUMBIA - ALBERTA INTERCONNECTION
800 MW TIE. 800 MW ASSISTANCE SUBJECT TO AVAILABILITY
1996 - PERIOD: 3

EQUIVALENT ASSISTING UNIT

OUTAGE (MW)	PROBABILITY (p.u.)	OUTAGE (MW)	PROBABILITY (p.u.)	OUTAGE (MW)	PROBABILITY (p.u.)
0.0	0.9891394	230.0	0.0000037	501.0	0.0000003
2.0	0.0000089	241.0	0.0000023	511.0	0.0000002
4.0	0.0000114	250.0	0.0000036	520.0	0.0000003
6.0	0.0000065	260.0	0.0000031	531.0	0.0000004
8.0	0.0000118	270.0	0.0000030	540.0	0.0000002
10.0	0.0000211	281.0	0.0000008	550.0	0.0000003
21.0	0.0000103	292.0	0.0000014	561.0	0.0000002
30.0	0.0000168	300.0	0.0000029	571.0	0.0000001
40.0	0.0000052	311.0	0.0000015	580.0	0.0000001
51.0	0.0000103	322.0	0.0000009	591.0	0.0000002
61.0	0.0000052	330.0	0.0000013	601.0	0.0000001
70.0	0.0000077	340.0	0.0000008	610.0	0.0000003
81.0	0.0000126	351.0	0.0000010	620.0	0.0000001
90.0	0.0000085	361.0	0.0000010	631.0	0.0000001
100.0	0.0000124	371.0	0.0000006	642.0	0.0000001
111.0	0.0000069	381.0	0.0000011	651.0	0.0000001
121.0	0.0000047	391.0	0.0000005	661.0	0.0000001
130.0	0.0000043	401.0	0.0000008	670.0	0.0000001
141.0	0.0000045	411.0	0.0000010	680.0	0.0000007
151.0	0.0000027	421.0	0.0000005	691.0	0.0000001
160.0	0.0000090	431.0	0.0000007	700.0	0.0000001
170.0	0.0000035	441.0	0.0000004	710.0	0.0000001
181.0	0.0000038	450.0	0.0000005	720.0	0.0000001
192.0	0.0000036	460.0	0.0000008	731.0	0.0000000
201.0	0.0000033	471.0	0.0000004	742.0	0.0000000
211.0	0.0000026	480.0	0.0000006	800.0	0.0099993
220.0	0.0000024	490.0	0.0000002		

Figure 4.3: Equivalent assisting unit model of British Columbia in December 1996.

interesting conclusion: The effect of this equivalent assisting unit of capacity subject to availability is practically the same as the effect of a firm capacity equivalent assisting unit. This conclusion comes from the fact that the probabilities of occurrence of all intermediate states are very small compared to the probabilities of the first and last states. Then, if all the intermediate states were neglected, the equivalent assisting unit at the receiving end of the tie-line would become:

Outage (MW)	Probability of occurrence
0.0	0.9891394
800.0	0.0099993

This table is similar to that for a firm capacity equivalent assisting unit. It is worth noting that the probability of occurrence of the 800 MW outage is practically 0.01, which corresponds to the value of Forced Outage Rate of the transmission line that interconnects B.C. and Alberta. Then, at the sending end of the tie-line, the probability would be practically zero, making the "unit" fully reliable at the sending end, as if it were a firm capacity agreement.

A test of this conclusion was conducted for CASE B3 in the year 1996. This time the capacity assistance of 800 MW was considered firm capacity and the results obtained under this operating condition were compared to the results obtained in CASE B3 for the same year.

1996 CASE B3 800 MW	LOLE (hrs/year)	LOEE (MWh)
Subject to availability	0.43066	62.959
Firm	0.43046	62.923
Difference of:	0.00002	0.036

The values of the reliability indices obtained considering firm capacity assistance are lower than the figures calculated considering the assistance subject to availability, which is an expected result. For practical purposes, however, the difference is negligible.

4.4 ALBERTA INTERCONNECTED WITH BRITISH COLUMBIA AND SASKATCHEWAN

In this section, the reliability indices for Alberta are calculated considering interconnections with B.C. and Sask.

The capacity assistance from B.C. is assumed firm in all the cases analysed in this section. The reason for this assumption is simply that there is no significant difference between the results obtained modelling the B.C. electric system as firm capacity assistance and the results obtained in the case of capacity assistance subject to availability, as demonstrated in Section 4.3.

The capacity assistance from B.C. is set to 300 MW, 600 MW, and 800 MW. The first and second levels of assistance are considered very likely to happen during the study period. The assistance level of 800 MW, although not considered probable for the reasons stated in Section 4.3, is used in this section for illustration purposes.

Capacity assistance from (or to) Saskatchewan is set to 100 MW and the unavailability factor of the tie-line is assumed 1%, the same as for the Alberta - B.C. tie-line.

4.4.1 Alberta receives capacity assistance from B.C. and Saskatchewan

CASE C1. Assistance from B.C. 300 MW firm.
Assistance from Sask. 100 MW subject to availability.

CASE C2. Assistance from B.C. 300 MW firm.
Assistance from Sask. 100 MW firm.

The reliability indices under these operating conditions are presented in Table 4.8 and Table 4.9 respectively. Comparison of these results (Table 4.10 and Table 4.11) shows the difference between modelling the Sask. system to be firm capacity assistance and capacity assistance subject to availabilty. The differences exist because the generators in Sask. are less reliable than the generators in B.C.. The generating system in Sask. consists mainly of thermal plants with F.O.R. ranging between 4% and 8%, while the B.C. system is made-up mainly of hydroelectric plants with F.O.R. lower than 2%. Also, reserves in Sask. are substantially lower than in B.C..

YEAR	LOLE hrs/year	LOEE MWh	ADDITIONAL CAPACITY REQUIRED
1992	0.67882	97.91	Yes
1993	0.98981	143.832	Yes
1994	1.392	205.244	Yes
1995	2.30299	344.61	Yes
1996	2.85752	443.115	Yes

Table 4.8: CASE C1
Assistance from B.C. 300 MW firm.
Assistance from Sask. 100 MW subject to availability.

YEAR	LOLE hrs/year	LOEE MWh	ADDITIONAL CAPACITY REQUIRED
1992	0.64982	91.811	Yes
1993	0.88983	126.709	Yes
1994	1.32994	195.367	Yes
1995	2.1813	323.911	Yes
1996	2.6558	406.387	Yes

Table 4.9: CASE C2
Assistance from B.C. 300 MW firm.
Assistance from Sask. 100 MW firm.

YEAR	LOLE hrs/year	LOEE MWh
1992	-0.0290	-6.0990
1993	-0.1000	-17.1230
1994	-0.0621	-9.8770
1995	-0.1217	-20.6990
1996	-0.2017	-36.7280

Table 4.10: CASE C2 - CASE C1
Difference between LOLE and LOEE calculated considering Saskatchewan as firm capacity assistance and assistance subject to availability.

YEAR	LOLE DECREASE	LOEE DECREASE
1992	4.46%	6.64%
1993	11.24%	13.51%
1994	4.67%	5.06%
1995	5.58%	6.39%
1996	7.60%	9.04%

Table 4.11: Improved reliability from CASE C1 to CASE C2.

Low reserves and high F.O.R. produce equivalent assisting unit models with significantly higher probabilities in the intermediate states than those of a more reliable system such as B.C.. Figure 4.4 shows the equivalent unit of 100 MW capacity assistance from Sask. corresponding to December 1996. Also, the probabilities of the first and last states are much lower than the probabilities of the same states calculated for the B.C. system.

When equivalent assisting units of the Saskatchewan system are calculated, it is not appropriate to neglect the intermediate states of the equivalent units, as done for the B.C. system, and the capacity assistance from Sask. should not be considered firm, unless a firm capacity contract were agreed to between respective utilities.

<u>CASE C3.</u> Assistance from B.C. 600 MW firm.
Assistance from Sask. 100 MW subject
to availability.

In this case, the assistance from B.C. is increased to 600 MW and the assistance from Sask. remains at 100 MW

SASKATCHEWAN - ALBERTA INTERCONNECTION
100 MW TIE. 100 MW ASSISTANCE SUBJECT TO AVAILABILITY
1996 - PERIOD: 3

EQUIVALENT ASSISTING UNIT

OUTAGE (MW)	PROBABILITY (p.u.)	OUTAGE (MW)	PROBABILITY (p.u.)	OUTAGE (MW)	PROBABILITY (p.u.)
0.0	0.6925609	48.0	0.0055468	97.0	0.0028626
1.0	0.0005355	51.0	0.0003242	99.0	0.0021828
3.0	0.0018745	53.0	0.0008639	100.0	0.1785676
6.0	0.0027479	55.0	0.0011665		
8.0	0.0047493	58.0	0.0114026		
10.0	0.0040341	61.0	0.0000007		
13.0	0.0033869	63.0	0.0120722		
16.0	0.0006454	65.0	0.0008997		
18.0	0.0031974	68.0	0.0036831		
20.0	0.0051657	70.0	0.0023413		
22.0	0.0111957	72.0	0.0058571		
25.0	0.0075531	75.0	0.0016168		
28.0	0.0011699	78.0	0.0009319		
30.0	0.0028822	80.0	0.0011789		
32.0	0.0036089	82.0	0.0025082		
35.0	0.0034351	84.0	0.0044446		
38.0	0.0005713	87.0	0.0032281		
41.0	0.000821	90.0	0.0006424		
43.0	0.0009723	92.0	0.0014827		
45.0	0.0027202	94.0	0.0023128		

Figure 4.4: Equivalent assisting unit model of Saskatchewan in December 1996.

subject to availability. This is perhaps one of the most probable scenarios that can be forseen at this point in time. Results of this case are presented in Table 4.12. Under these operating conditions, ALberta would not need new generating facilities until 1994.

CASE C4. Assistance from B.C. 800 MW firm.
Assistance from Sask. 100 MW subject
to availability.

In this case, the assistance from B.C. is allowed to go as high as 800 MW and the assistance from Sask. remains at 100 MW subject to availability. Results of this case are presented in Table 4.13. Under these operating conditions, Alberta would not need new generating facilities until 1996.

Comparison of the results obtained in cases A, C1, C3, and C4 are presented in Figure 4.5 and Figure 4.6. The effect of 100 MW capacity assistance from Saskatchewan is a delay of 2 years on the need for new generating facilities in Alberta in cases C3 and C4, compared to cases B2 and B3 respectively.

YEAR	LOLE hrs/year	LOEE MWh	ADDITIONAL CAPACITY REQUIRED
1992	0.122	19.91	No
1993	0.18	23.85	No
1994	0.258	35.45	Yes
1995	0.432	61.51	Yes
1996	0.546	80.26	Yes

Table 4.12: CASE C3
Assistance from B.C. 600 MW firm.
Assistance from Sask. 100 MW subject to availability.

YEAR	LOLE hrs/year	LOEE MWh	ADDITIONAL CAPACITY REQUIRED
1992	0.056	6.26	No
1993	0.081	9.22	No
1994	0.1148	14.02	No
1995	0.194	26.57	No
1996	0.251	33.71	Yes, marginal

Table 4.13: CASE C4
Assistance from B.C. 800 MW firm.
Assistance from Sask. 100 MW subject to availability.

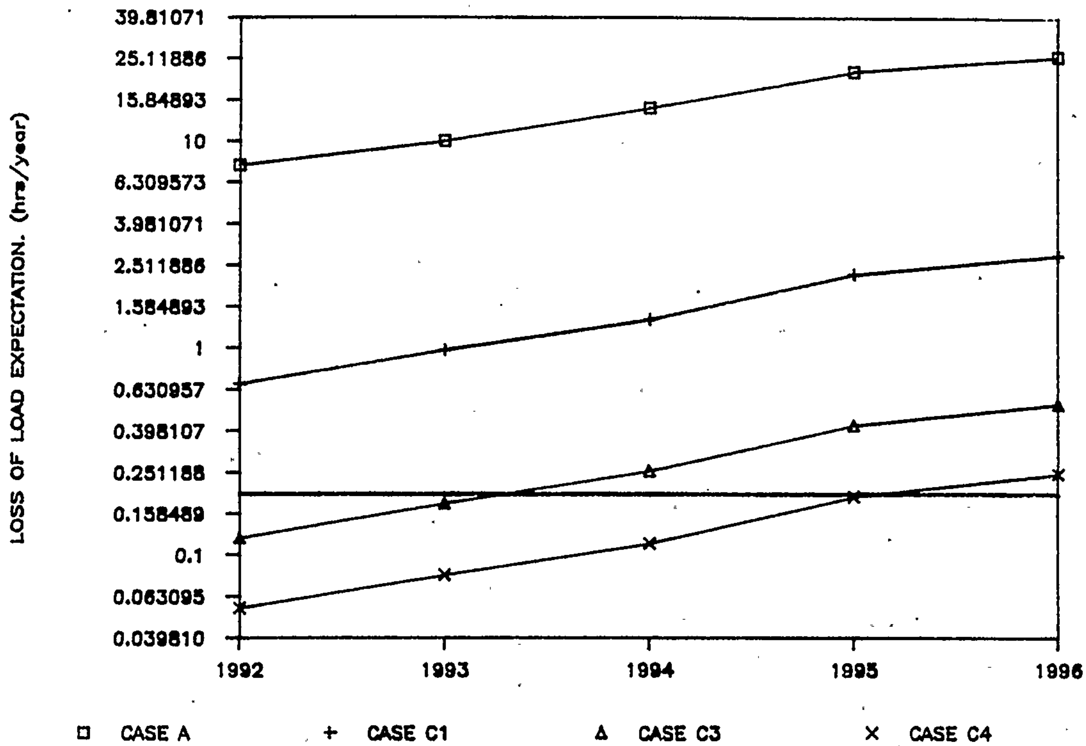

Figure 4.5: Loss of Load Expectation.

Alberta isolated vs Alberta receiving capacity assistance from B.C. and Sask.

where:

CASE A. Alberta isolated.

CASE C1. Assistance from B.C. 300 MW firm.

Assistance from Sask. 100 MW subject to availability.

CASE C3. Assistance from B.C. 600 MW firm.

Assistance from Sask. 100 MW subject to availability.

CASE C4. Assistance from B.C. 800 MW.firm.

Assistance from Sask. 100 MW subject to availability.

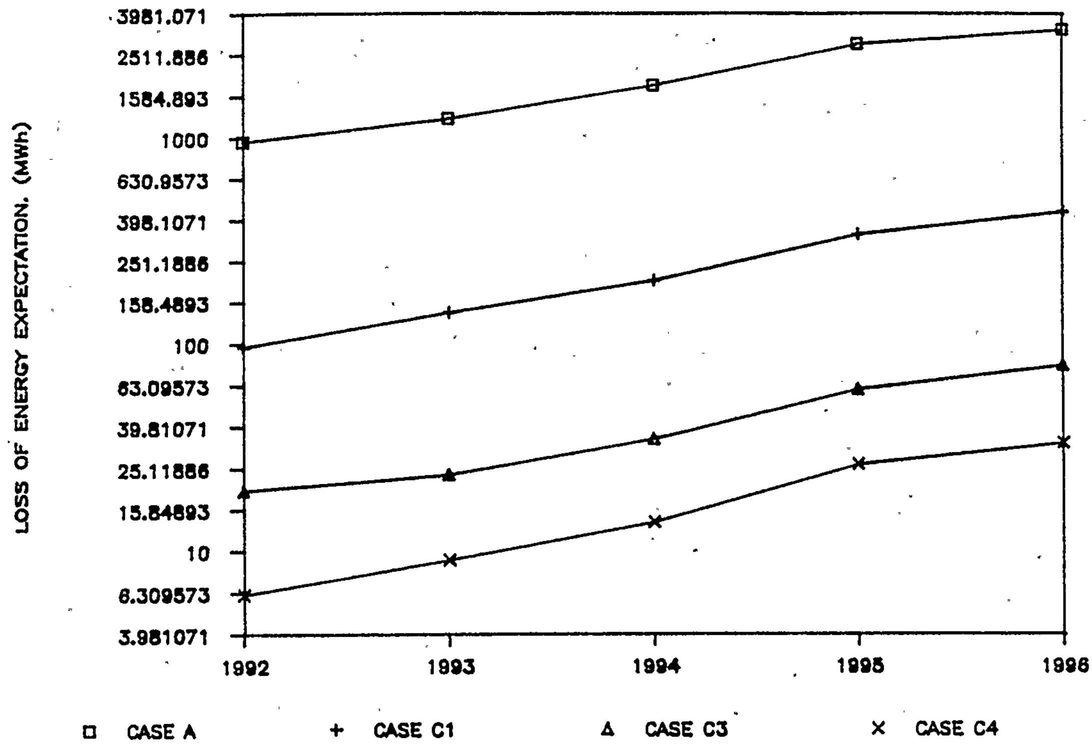

Figure 4.6: Loss of Energy Expectation.

Alberta isolated vs Alberta receiving capacity assistance from B.C. and Sask.

where:

CASE A. Alberta isolated.

CASE C1. Assistance from B.C. 300 MW firm.

Assistance from Sask. 100 MW subject to availability.

CASE C3. Assistance from B.C. 600 MW firm.

Assistance from Sask. 100 MW subject to availability.

CASE C4. Assistance from B.C. 800 MW.firm.

Assistance from Sask. 100 MW subject to availability.

4.4.2 Alberta Assists Saskatchewan, B.C. Assists Alberta.

CASE D1. Assistance from B.C. 300 MW firm.
Assistance to Sask. 100 MW.

CASE D2. Assistance from B.C. 600 MW firm.
Assistance to Sask. 100 MW.

CASE D3. Assistance from B.C. 800 MW firm.
Assistance to Sask. 100 MW.

In these cases, the capacity assistance from B.C. is set at 300 MW, 600 MW, and 800 MW. This time, however, Alberta supplies 100 MW of capacity assistance to Sask. The results obtained under these operating conditions are presented in tables 4.14, 4.15, and 4.16 respectively.

The likelihood of these scenarios cannot be assessed effectively at this time because the operation of Alberta and Saskatchewan as an interconnected system is unknown. It can be assumed, however, that during 1992 and 1993 Alberta may assist Saskatchewan, and from 1994 and beyond the system could supply Alberta with assistance subject to availability. This assumption is based on the

YEAR	LOLE hrs/year	LOEE MWh	ADDITIONAL CAPACITY REQUIRED
1992	2.397	356.72	Yes
1993	3.181	481.21	Yes
1994	4.564	726.64	Yes
1995	7.053	1149.61	Yes
1996	8.663	1418.12	Yes

Table 4.14: CASE D1
Assistance from B.C. 300 MW firm.
Assistance to Sask. 100 MW.

YEAR	LOLE hrs/year	LOEE MWh	ADDITIONAL CAPACITY REQUIRED
1992	0.449	62.82	Yes
1993	0.593	86.32	Yes
1994	0.884	132.71	Yes
1995	1.414	217.31	Yes
1996	1.744	272.07	Yes

Table 4.15: CASE D2
Assistance drom B.C. 600 MW firm.
Assistance to Sask. 100 MW.

YEAR	LOLE hrs/year	LOEE MWh	ADDITIONAL CAPACITY REQUIRED
1992	0.204	27.76	No, marginal
1993	0.272	37.58	Yes
1994	0.409	60.06	Yes
1995	0.649	98.77	Yes
1996	0.781	122.91	Yes

Table 4.16: CASE D3
Assistance from B.C. 800 MW.
Assistance to Sask. 100 MW.

installation of a new generating unit of 275 MW in Saskatchewan, in the year 1994.

Comparison of the results obtained in cases A, D1, D2, and D3 are presented in Figure 4.7 and Figure 4.8. The effect of Saskatchewan taking 100 MW of capacity from the reserves in Alberta (throughout the entire study period) is a decrease in the reliability of supply in this province. However, the decrease is offset by the large assistance that Alberta receives from B.C.

4.4.3 Alberta Assists B.C.

<u>CASE E1.</u> Assistance to B.C. 300 MW.
Assistance to Sask. 100 MW.

<u>CASE F1.</u> Assistance to B.C. 300 MW.
Assistance from Sask. 100 MW.

Cases E1 and F1, in which Alberta supplies B.C. with assistance capacity, are included in this study to cover the possibility of B.C. exporting such large amounts of capacity to the Western United States that it requires a

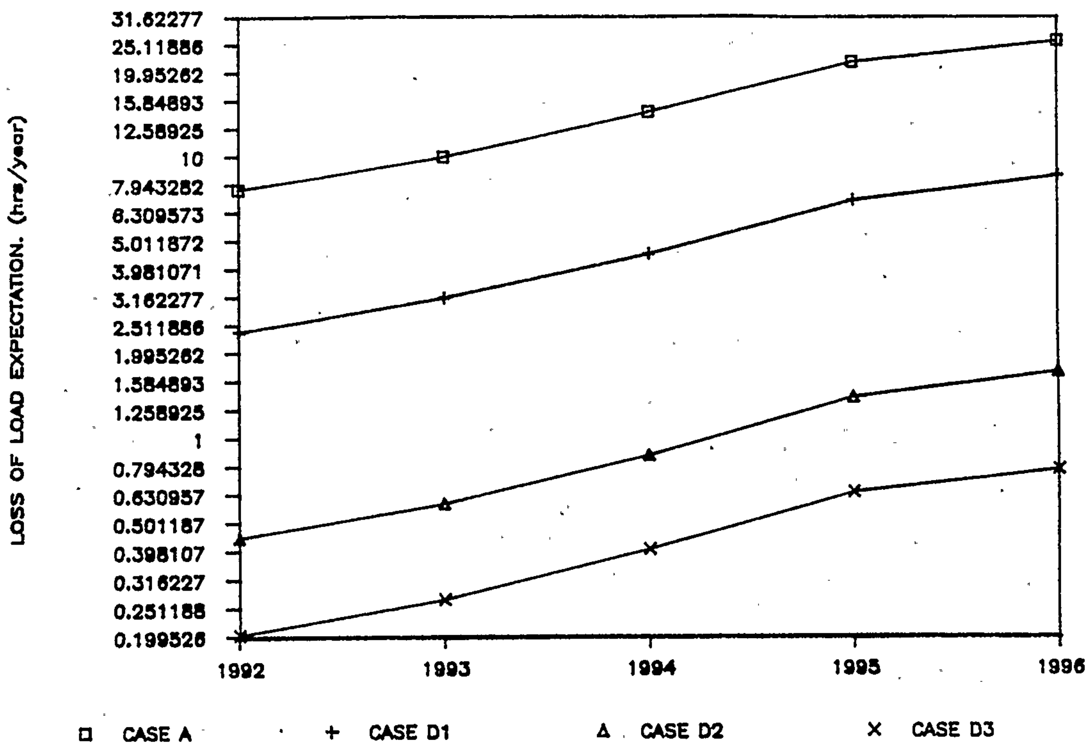

Figure 4.7: Loss of Load Expectation.

Alberta isolated vs Alberta assisting Sask. B.C. assisting Alberta.

where:

CASE A. Alberta isolated.

CASE D1. Assistance from B.C. 300 MW firm.
Assistance to Sask. 100 MW.

CASE D2. Assistance from B.C. 600 MW firm.
Assistance to Sask. 100 MW.

CASE D3. Assistance from B.C. 800 MW firm.
Assistance to Sask. 100 MW.

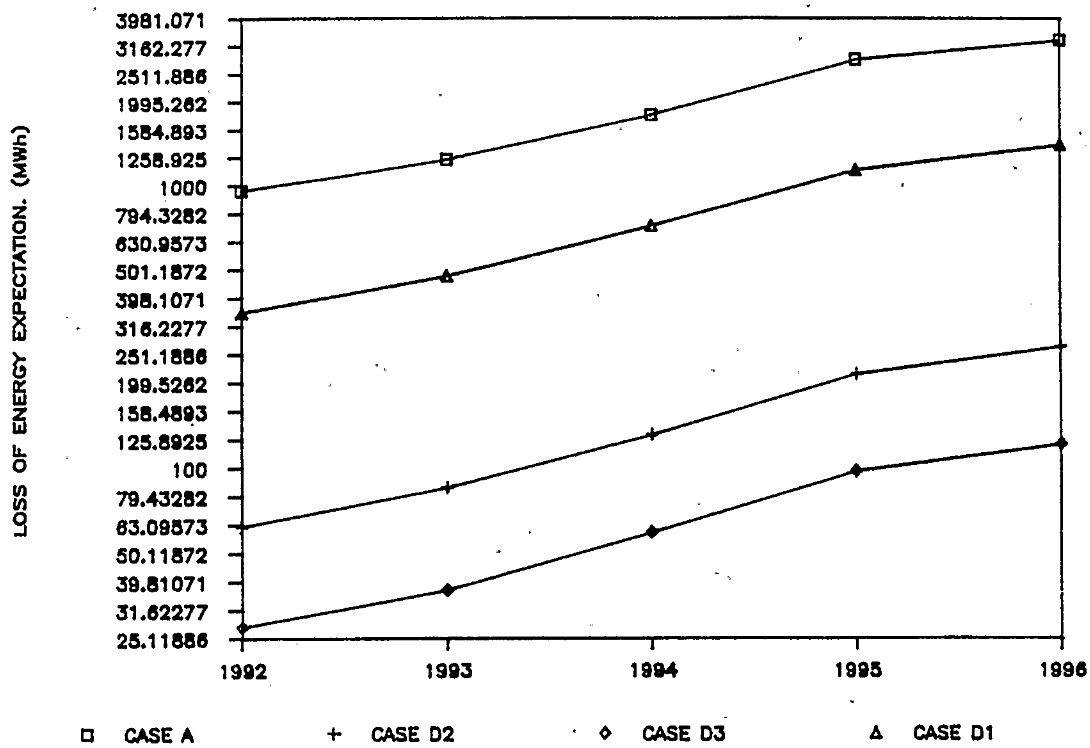

Figure 4.8: Loss of Energy Expectation.

Alberta isolated vs Alberta assisting Sask. B.C. assisting Alberta.

where:

CASE A. Alberta isolated.

CASE D1. Assistance from B.C. 300 MW firm.
Assistance to Sask. 100 MW.

CASE D2. Assistance from B.C. 600 MW firm.
Assistance to Sask. 100 MW.

CASE D3. Assistance from B.C. 800 MW firm.
Assistance to Sask. 100 MW.

continuous supply of capacity assistance from Alberta. The likelihood of this scenario depends on the ability of B.C. to find markets for its large reserve capacity. The results for cases E1 and F1 are presented in tables 4.17 and 4.18 respectively. Under these operating conditions the reliability of supply in Alberta is lower than the case where Alberta is isolated (CASE A), as can be seen in Figure 4.9 and Figure 4.10. This is caused by the capacity assistance to B.C., which reduces the reserves in this province by 300 MW througout the entire study period.

4.5 DEVELOPMENT OF THE ALBERTA INTERCONNECTED SYSTEM

The cases presented in sections 4.4.2 and 4.4.3 consider Alberta supplying continuous capacity assistance to B.C. and/or Saskatchewan throughout the entire study period. This is certainly a very strong imposition on the Alberta generating system, and it explains the decrease in reliability under these operating conditions. However, it is improbable that Alberta would commit a significant part of its reserve capacity to help a neighboring power system. Also, it is less likely for Alberta to have a constant amount of capacity flowing out of this province

YEAR	LOLE hrs/year	LOEE MWh	ADDITIONAL CAPACITY REQUIRED
1992	69.31	12854.3	Yes
1993	88.25	16312.1	Yes
1994	118.44	22810.9	Yes
1995	163.68	32943.2	Yes
1996	190.88	39020.5	Yes

Table 4.17: CASE E1
Assistance to B.C. 300 MW.
Assistance to Sask. 100 MW.

YEAR	LOLE hrs/year	LOEE MWh	ADDITIONAL CAPACITY REQUIRED
1992	24.25	4171.6	Yes
1993	33.48	5852.9	Yes
1994	43.45	7916.8	Yes
1995	64.38	11841.9	Yes
1996	77.21	14485.8	Yes

Table 4.18: CASE F1
Assistance to B.C. 300 MW.
Assistance from Sask. 100 MW subject to availability.

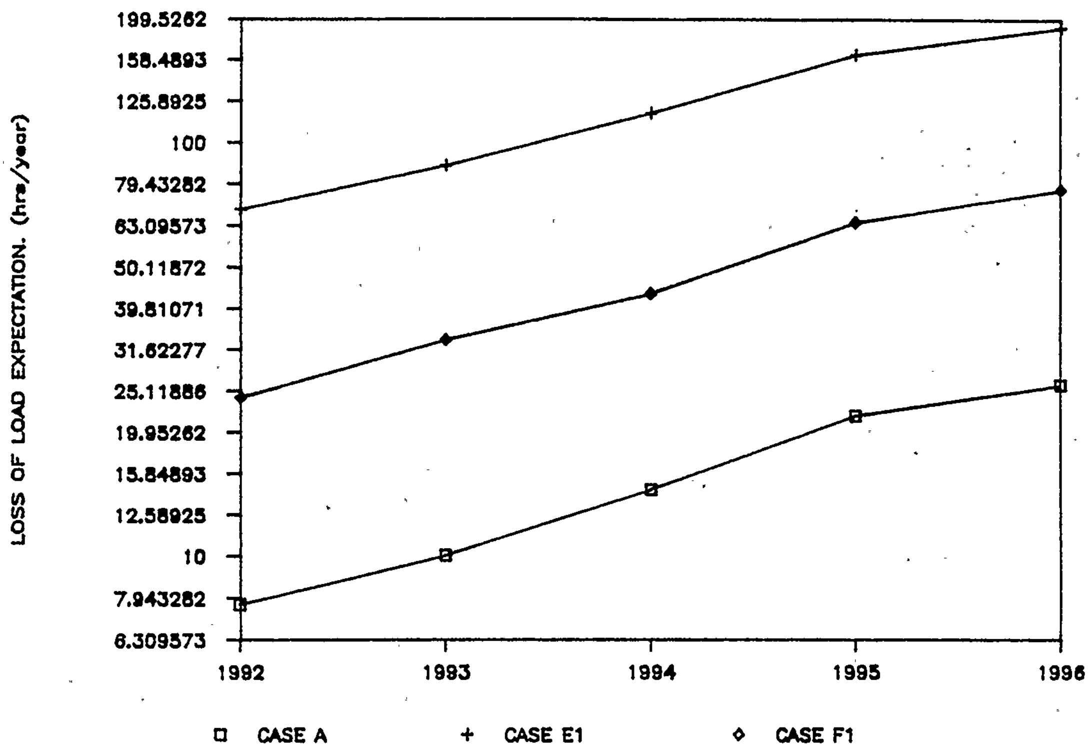

Figure 4.9: Loss of Load Expectation.

Alberta isolated vs Alberta assisting B.C.

where:

CASE A. Alberta isolated.

CASE E1. Assistance to B.C. 300 MW.

Assistance to Sask. 100 MW.

CASE F1. Assistance to B.C. 300 MW.

Assistance from Sask. 100 MW subject to availability.

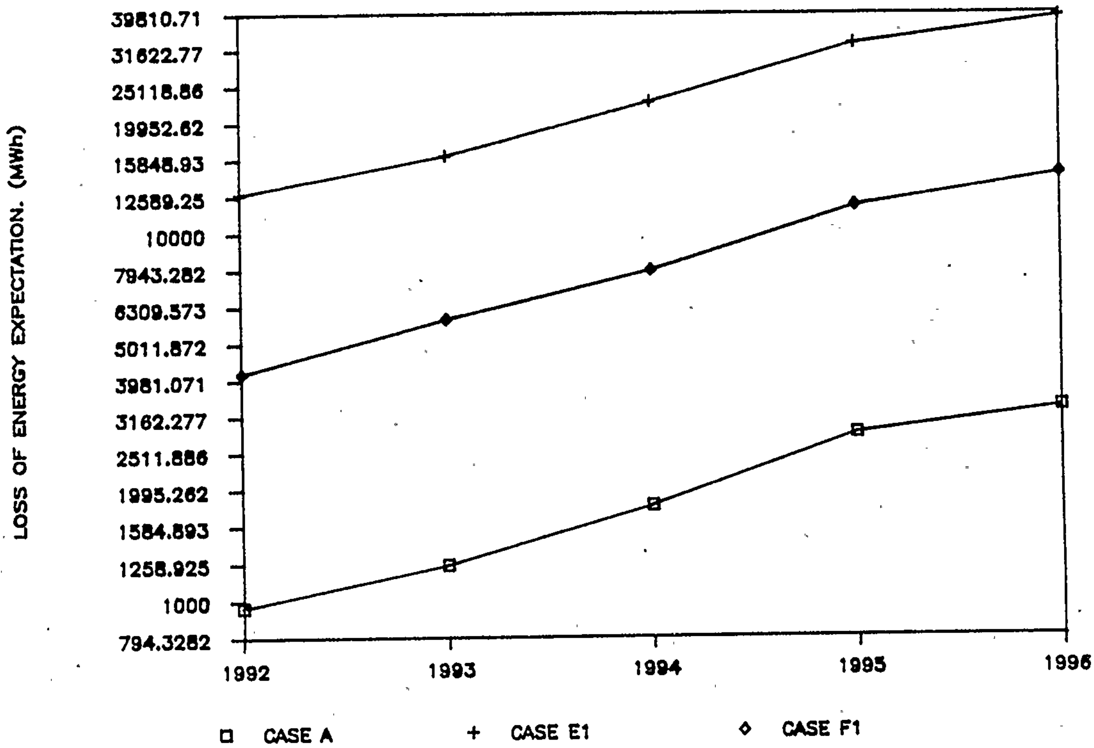

Figure 4.10: Loss of Energy Expectation.

Alberta isolated vs Alberta assisting B.C.

where:

CASE A. Alberta isolated.

CASE E1. Assistance to B.C. 300 MW.

Assistance to Sask. 100 MW.

CASE F1. Assistance to B.C. 300 MW.

Assistance from Sask. 100 MW subject to availability.

at each and every hour during an entire year, unless, of course, there were strong economic reasons to overbuild the generating system in Alberta in order to supply continuous capacity assistance, and at the same time, achieve the desired reliability of supply.

It is more likely that the operating conditions during the study period will be similar to the operation of Alberta and B.C. since they were interconnected in 1985, i.e. during normal conditions the flow of power through the tie-line is determined mainly by economic reasons. However, if one system encounters difficulties that can lead to a loss-of-load situation in that system, the other system supplies capacity assistance until the difficulties are overcome. In other words, both Alberta and B.C. can conduct their reliability studies (and determine their static capacity requirements) considering the neighboring interconnected power system as capacity assistance subject to available reserve and random outages.

Assuming that the existing operating conditions between Alberta and B.C. will prevail, and that similar conditions will exist between Alberta and Saskatchewan during the study period, the cases presented in Section 4.4.1 (cases: C1, C3, and C4) are the most likely scenarios, and they are appropiate in addressing the question of reliability of supply and of the static capacity requirements in Alberta.

In these cases, the amount of capacity assistance that Alberta receives from B.C. is set at 300 MW in CASE C1, 600 MW in CASE C3, and 800 MW in CASE C4. In the first case, which can be considered a pessimistic case, Alberta needs new generating facilities in 1992. In the second case, which the author believes is a more probable case, Alberta does not require new generating facilities until 1994. In the last case, which can be considered a very optimistic case, Alberta does not require new generating facilities until 1996.

It should be noted that the static capacity requirements referred to in the above paragraph are valid only for the forecast of peak demand assumed in this study. Also, changes in the generator and/or load data in any of the power systems will produce different values of reliability indices, which can lead to different static capacity requirements.

Chapter V

CONCLUSIONS AND SUGGESTIONS FOR FURTHER WORK

The equivalent assisting unit method for calculation of reliability indices of interconnected power systems has been implemented in a computer model.

The model, which is made up of two (2) separate programs, was designed to include the effects of random outages as well as scheduled outages of thermal generating units. It also takes into account limits on hydroelectric energy generation, and capacity of tie lines as well as their probabilities of failure. The model calculates reliability indices only for the power system of interest (Alberta in this case) and it can simulate up to four (4) different modes of operation between the system of interest and the systems interconnected to it.

The model has been used to investigate the reliability of supply and the static capacity requirements in Alberta considering the effects of interconnections with British Columbia (B.C.) and Saskatchewan (Sask.).

The investigation covered the period 1992 to 1996 inclusive. It consisted of the calculation of Loss of Load Expectation (LOLE) and Loss of Energy Expectation (LOEE) in Alberta under several operating conditions.

The operating conditions include a case in which Alberta is isolated from its neighboring power systems, three (3) cases in which Alberta is interconnected only to B.C., and nine (9) cases in which Alberta is interconnected to B.C. and Sask.

Comparison of results obtained for the cases of Alberta isolated and Alberta interconnected only to B.C. (cases A, B1, B2 and B3) shows a significant increase in the reliability of supply in Alberta. (Refer to Section 4.3, Figures 4.1 and 4.2)

The capacity assistance from B.C. has been considered to be subject to available reserves and random outages in that power system. However, it was found that such capacity assistance has the same effect as firm capacity assistance (or assistance fully reliable at the sending end of the tie-line) on the reliability indices. This is because the B.C. electric system has very large reserves, relative to the assumed amount of capacity assistance to

Alberta, and that in general the generators in that system are very reliable. (Refer to Section 4.3). This conclusion validates previous reliability studies (reference [4]) in which the B.C. system was modelled into the Alberta system as a generator of capacity equal to the amount of capacity assistance and with Forced Outage Rate (FOR) equal to the tie-line unavailability factor.

In each of the remaining cases, the Saskatchewan electric system was interconnected to Alberta.

A test of the difference between modelling the Saskatchewan electric system as firm capacity assistance and assistance subject to availability was conducted. It was found that the LOLE and LOEE in Alberta, for the case of Sask. supplying a firm capacity assistance, range from 4% to 13% lower than the case of Sask. supplying the same capacity assistance subject to availability and random outages. (Refer to Section 4.4.1, Table 4.11). Realistically, Sask. should be modelled as capacity assistance subject to availability, and it should not be assumed supplying firm capacity , unless, of course, there were a firm capacity agreement between Alta. and Sask.

Comparison of results obtained for the case of Alberta isolated (case A) and Alberta receiving capacity assistance from B.C. and Sask. (cases C1, C3, and C4) shows an even larger increase in the reliability of supply in Alberta, which is due to the additional support from Sask. (Refer to Section 4.4.1, Figures 4.5 and 4.6).

In cases D1, D2, and D3 Alberta supplies 100 MW of capacity assistance to Sask. throughout the entire study period. The results of these cases shows a decreased reliability of supply in Alberta, which is due to the capacity assistance to Sask. However, the decrease is offset by the large amounts of capacity assistance from B.C., which makes the reliability of supply in Alberta, under these operating conditions, better than the reliability of Alberta when isolated. (Refer to Section 4.4.2, Figures 4.7 and 4.8).

In the last two cases (E1 and F1) Alberta supplies 300 MW of capacity assistance to B.C. throughout the entire study period. As expected, under these operating conditions, the reliability of supply in Alberta was found to be lower than in the case of Alberta isolated. (Refer to Section 4.4.3, Figures 4.9 and 4.10)

If capacity assistance from B.C. is limited to 300 MW, Alberta would require new generating facilities in 1992. However, if capacity assistance from B.C. is 600 MW, Alberta would not need new generating facilities until 1994. If the capacity assistance from B.C. were allowed to be 800 MW, Alberta would not need new generating facilities until 1996. This conclusions are based on the assumption that cases C1, C2, and C4 represent the most appropiate scenarios in addressing the development of the Alberta electric system.

The approach to reliability of power systems taken in this study can be considered a very accurate approach because capacity outage probability tables, which represent all possible outage events in the generating system, were calculated for every period in all the study years, and for every power system. Also, equivalent assisting units were derived in every period from their corresponding outage tables.

To conclude this report, a summary of advantages and disadvantages of the computer model is presented in the following paragraphs. It should be pointed out that the list of disadvantages represents a source of topics for future research and development of the computer model.

Advantages of the model

- Automatic maintenance scheduling of thermal plants. The user can specify periods in which maintenance is not allowed.

- The year can be divided into any number of periods. (Limited only by computer memory).

- Capacity outage probability tables are calculated in each period. They can also be rounded at specified capacity increments.

- Schedule for the hydroelectric plants is calculated in each period.

- Equivalent assisting units of assisting neighboring systems are determined for each period.

- Calculation of LOLE is done by summing probabilities of loss of load calculated for each hour in the year.

- Up to four (4) power systems can be interconnected simultaneously to the system of interest.

- Up to four (4) tie lines between each neighboring system and the system of interest can be included (total of 16 tie lines).

- Four (4) different modes of operation between a neighboring system and the system of interest can be considered.

- The size of the program's output can be controlled by the user. The detailed output allows extensive checking.

- The model has a high number (40) of built-in error and warning messages.

Disadvantages of the model, topics for future enhancement.

- The model runs in a mainframe computer, it is not interactive.

- The computer time for a one-year simulation amounts to several minutes.

- Only LOLE and LOEE are calculated. The program does not compute the load carrying capability of the system of interest.

- The program does not model energy (or fuel) limited thermal plants, nor does it model environmental constraints, such as particle emissions, SO2 emissions, etc.

- Hydroelectric plants are treated as one single composite plant.

- The model does not modify the shape of the LDC's to reflect changes in load factor.

- The LDC's are treated as a set of discrete points. The model calculates straight lines between each pair of points.

- Only direct interconnections between the system of interest and the neighboring systems can be modelled. No indirect capacity assistance can be accommodated.

- Capacity assistance associated with specific generating units within the assisting system is not modelled.

Chapter VI

REFERENCES

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Appendix

DATA OF ELECTRIC POWER SYSTEMS

This appendix presents the complete database used in the execution of the computer program. It contains the characteristics of the power systems in Alberta, Saskatchewan, and British Columbia.

The data is arranged as follows.

- A list of generating units, which shows in each line, the unit's name, output, Forced Outage Rate (FOR), Planned Outage Rate (POR), and maintenance class.

- The characteristics of the hydroelectric generation for each period of the year.

- The annual peak load for all the study years.

- The ratio period to annual peak, the number of hours, and the Load Duration Curve (LDC) for each period of the year.

ALBERTA ELECTRIC SYSTEM

ALBERTA GENERATING SYSTEM 1992 - 1996

UNIT NAME	OUTPUT (MW)	FOR (pu)	POR (pu)	MAINT. CLASS (MW)
BATTLE RIVER 1	33.	0.038	.0438	30.
BATTLE RIVER 2	33.	0.007	.0438	30.
BATTLE RIVER 3	164.	0.024	.0603	160.
BATTLE RIVER 4	164.	0.016	.0603	160.
BATTLE RIVER 5	396.	0.043	.0822	400.
CLOVER BAR 1	172.	0.111	.0521	160.
CLOVER BAR 2	172.	0.033	.0521	160.
CLOVER BAR 3	172.	0.003	.0521	160.
CLOVER BAR 4	172.	0.021	.0521	160.
KEEPHILS 1	397.	0.071	.0822	400.
KEEPHILS 2	397.	0.075	.0822	400.
MEDICINE HAT 3	15.	0.013	.0383	30.
MEDICINE HAT 5	20.	0.009	.0301	30.
MEDICINE HAT 7	33.	0.004	.0383	30.
MEDICINE HAT 8	44.	0.034	.0493	30.
MEDICINE HAT 9	44.	0.012	.0493	30.
MILNER	151.	0.05	.0466	160.
RAINBOW LAKE 1	33.	0.041	.0438	30.
RAINBOW LAKE 2	44.	0.061	.0438	30.
ROSEDALE 8	72.	0.056	.0630	70.
ROSEDALE 9	72.	0.451	.0630	70.
ROSEDALE 10	72.	0.024	.0438	70.
SUNDANCE 1	296.	0.058	.0822	300.
SUNDANCE 2	303.	0.031	.0822	300.
SUNDANCE 3	377.	0.019	.0822	300.
SUNDANCE 4	387.	0.034	.0822	300.
SUNDANCE 5	387.	0.062	.0822	300.
SUNDANCE 6	387.	0.037	.0822	300.
WABAMUN 1	64.	0.018	.0466	70.
WABAMUN 2	64.	0.016	.0466	70.
WABAMUN 3	140.	0.083	.0630	160.
WABAMUN 4	280.	0.032	.0822	300.
SHEERNESS 1	383.	0.077	.0822	400.
SHEERNESS 2	383.	0.077	.0822	400.
GENESEE 2	406.	0.077	.0822	400.
GENESEE 1	406.	0.077	.0822	400.

HYDROELECTRIC GENERATION

PERIOD	MINIMUM OUTPUT (MW)	MAXIMUM OUTPUT (MW)	ENERGY GENERATION (MWh)
OCT	73.0	802	131600
NOV	74.0	802	133900
DEC	99.0	692	144000
JAN	100.0	692	152800
FEB	84.0	692	130600
MAR	68.0	802	121400
APR	68.0	802	98300
MAY	93.0	802	127800
JUN	158.0	802	216100
JUL	152.0	802	213300
AGO	112.0	802	165400
SEP	94.0	802	142000

LOAD CHARACTERISTICS

FORECAST PEAK DEMAND

YEAR	PEAK (MW)
1992	6711
1993	6766
1994	6849
1995	6937
1996	6956

PERIOD NO. 1: OCTOBER

RATIO PERIOD/ANNUAL
PEAK............: 0.8819
NUMBER OF HOURS: 744

LOAD DURATION CURVE. (pu).

LOAD	DURATION
1.0000	0.0000
0.9906	0.0013
0.9813	0.0013
0.9719	0.0027
0.9626	0.0094
0.9532	0.0134
0.9439	0.0416
0.9345	0.0792
0.9251	0.1221
0.9158	0.1852
0.9064	0.2577
0.8971	0.2980
0.8877	0.3289
0.8784	0.3490
0.8690	0.3718
0.8596	0.3879
0.8503	0.4094
0.8409	0.4309
0.8316	0.4591
0.8222	0.4765
0.8129	0.5020
0.8035	0.5262
0.7941	0.5544
0.7848	0.5799
0.7754	0.6054
0.7661	0.6242
0.7567	0.6497
0.7474	0.6671
0.7380	0.6819
0.7286	0.7020
0.7193	0.7195
0.7099	0.7423
0.7006	0.7624
0.6912	0.7960
0.6819	0.8510
0.6725	0.8953
0.6538	0.9732

PERIOD NO. 2: NOVEMBER

RATIO PERIOD/ANNUAL
PEAK............: 0.956
NUMBER OF HOURS: 720

LOAD DURATION CURVE. (pu).

LOAD	DURATION
1.0000	0.0000
0.9909	0.0042
0.9817	0.0111
0.9726	0.0194
0.9635	0.0292
0.9543	0.0361
0.9452	0.0486
0.9361	0.0708
0.9269	0.0931
0.9178	0.1208
0.9087	0.1847
0.8995	0.2361
0.8904	0.2931
0.8813	0.3375
0.8721	0.3792
0.8630	0.4097
0.8539	0.4292
0.8447	0.4486
0.8356	0.4667
0.8265	0.4931
0.8173	0.5097
0.8082	0.5347
0.7991	0.5528
0.7899	0.5819
0.7808	0.5958
0.7717	0.6194
0.7625	0.6417
0.7534	0.6625
0.7443	0.6806
0.7351	0.6986
0.7260	0.7250
0.7169	0.7417
0.7077	0.7681
0.6986	0.7958
0.6895	0.8292
0.6803	0.8764
0.6621	0.9556

0.6351	0.9960
0.6257	1.0000
0.0000	1.0000

PERIOD NO. 3:   DECEMBER

RATIO PERIOD/ANNUAL
PEAK...........:   1
NUMBER OF HOURS: 744

LOAD DURATION CURVE. (pu).

LOAD	DURATION
1.0000	0.0000
0.9911	0.0013
0.9823	0.0040
0.9734	0.0067
0.9646	0.0121
0.9557	0.0255
0.9469	0.0349
0.9380	0.0578
0.9291	0.0833
0.9203	0.1169
0.9114	0.1640
0.9026	0.1909
0.8937	0.2285
0.8849	0.2688
0.8760	0.3024
0.8671	0.3387
0.8583	0.3898
0.8494	0.4180
0.8406	0.4489
0.8317	0.4812
0.8229	0.5000
0.8140	0.5309
0.8052	0.5565
0.7963	0.5874
0.7874	0.6008
0.7786	0.6344
0.7697	0.6626
0.7609	0.7124
0.7520	0.7554
0.7432	0.7917
0.7343	0.8212
0.7254	0.8575

0.6529	0.9847
0.6346	1.0000
0.0000	1.0000

PERIOD NO. 4:   JANUARY

RATIO PERIOD/ANNUAL
PEAK...........:   0.9156
NUMBER OF HOURS: 744

LOAD DURATION CURVE. (pu).

LOAD	DURATION
1.0000	0.0000
0.9910	0.0040
0.9820	0.0081
0.9730	0.0121
0.9640	0.0161
0.9550	0.0309
0.9460	0.0538
0.9370	0.0712
0.9280	0.0954
0.9190	0.1358
0.9100	0.1640
0.9010	0.1949
0.8920	0.2298
0.8830	0.2769
0.8740	0.3038
0.8650	0.3320
0.8560	0.3737
0.8470	0.4180
0.8380	0.4583
0.8290	0.4866
0.8201	0.5027
0.8111	0.5282
0.8021	0.5390
0.7931	0.5672
0.7841	0.5914
0.7751	0.6371
0.7661	0.6573
0.7571	0.6815
0.7481	0.6989
0.7391	0.7258
0.7301	0.7392
0.7211	0.7755

0.7166	0.8804
0.7077	0.9207
0.6989	0.9422
0.6900	0.9677
0.6812	0.9812
0.6723	0.9906
0.6634	1.0000
0.0000	1.0000

PERIOD NO. 5: FEBRUARY

RATIO PERIOD/ANNUAL
PEAK............: 0.8721
NUMBER OF HOURS: 672

LOAD DURATION CURVE. (pu).

LOAD	DURATION
1.0000	0.0000
0.9907	0.0072
0.9814	0.0172
0.9721	0.0388
0.9628	0.0661
0.9535	0.1307
0.9442	0.2126
0.9349	0.2888
0.9255	0.3534
0.9162	0.3822
0.9069	0.4181
0.8976	0.4282
0.8883	0.4382
0.8790	0.4583
0.8697	0.4842
0.8604	0.5172
0.8511	0.5460
0.8418	0.5690
0.8325	0.5747
0.8232	0.5819
0.8139	0.6034
0.8045	0.6236
0.7952	0.6595
0.7859	0.6782
0.7766	0.6997
0.7673	0.7155
0.7580	0.7356
0.7487	0.7557

0.7121	0.8118
0.7031	0.8374
0.6941	0.8602
0.6851	0.8938
0.6671	0.9328
0.6581	0.9583
0.6311	1.0000
0.0000	1.0000

PERIOD NO. 6: MARCH

RATIO PERIOD/ANNUAL
PEAK............: 0.8444
NUMBER OF HOURS: 744

LOAD DURATION CURVE. (pu).

LOAD	DURATION
1.0000	0.0000
0.9904	0.0094
0.9809	0.0175
0.9713	0.0390
0.9618	0.0780
0.9522	0.1331
0.9427	0.1801
0.9331	0.2231
0.9236	0.2742
0.9140	0.3239
0.9044	0.3696
0.8949	0.3898
0.8853	0.4099
0.8758	0.4395
0.8662	0.4597
0.8567	0.4825
0.8471	0.5040
0.8375	0.5255
0.8280	0.5551
0.8184	0.5833
0.8089	0.6062
0.7993	0.6263
0.7898	0.6546
0.7802	0.6801
0.7707	0.7043
0.7611	0.7218
0.7515	0.7500
0.7420	0.7728

0.7394	0.7802
0.7301	0.8132
0.7208	0.8764
0.7115	0.9325
0.7022	0.9684
0.6929	0.9971
0.6835	1.0000
0.0000	1.0000

PERIOD NO. 7: APRIL

RATIO PERIOD/ANNUAL
PEAK...........: 0.7967
NUMBER OF HOURS: 720

LOAD DURATION CURVE. (pu).

LOAD	DURATION
1.0000	0.0000
0.9906	0.0070
0.9812	0.0181
0.9717	0.0445
0.9623	0.0918
0.9529	0.1613
0.9435	0.2350
0.9341	0.2712
0.9246	0.2921
0.9152	0.3463
0.9058	0.3574
0.8964	0.3713
0.8869	0.3811
0.8775	0.3894
0.8681	0.3992
0.8587	0.4228
0.8493	0.4562
0.8398	0.4826
0.8304	0.5021
0.8210	0.5410
0.8116	0.5675
0.8021	0.5897
0.7927	0.6189
0.7833	0.6439
0.7739	0.6620
0.7645	0.6787
0.7550	0.7010

0.7324	0.8051
0.7229	0.8387
0.7133	0.8723
0.7038	0.9395
0.6942	0.9664
0.6846	0.9906
0.6751	0.9987
0.6655	1.0000
0.0000	1.0000

PERIOD NO. 8: MAY

RATIO PERIOD/ANNUAL
PEAK...........: 0.8141
NUMBER OF HOURS: 744

LOAD DURATION CURVE. (pu).

LOAD	DURATION
1.0000	0.0000
0.9898	0.0081
0.9795	0.0269
0.9693	0.0645
0.9590	0.1237
0.9488	0.1815
0.9385	0.2285
0.9283	0.2554
0.9180	0.2702
0.9078	0.2890
0.8975	0.3145
0.8873	0.3387
0.8770	0.3495
0.8668	0.3710
0.8565	0.3911
0.8463	0.4194
0.8360	0.4449
0.8258	0.4664
0.8155	0.4960
0.8053	0.5228
0.7950	0.5497
0.7848	0.5901
0.7745	0.6263
0.7643	0.6532
0.7540	0.6626
0.7438	0.6788
0.7335	0.6922

0.7456	0.7274
0.7362	0.7399
0.7268	0.7900
0.7173	0.8498
0.7079	0.9026
0.6985	0.9444
0.6891	0.9680
0.6797	0.9875
0.6702	0.9958
0.6608	0.9986
0.6514	1.0000
0.0000	1.0000

PERIOD NO. 9: JUNE

RATIO PERIOD/ANNUAL
PEAK............: 0.8298
NUMBER OF HOURS: 720

LOAD DURATION CURVE. (pu).

LOAD	DURATION
1.0000	0.0000
0.9913	0.0014
0.9826	0.0042
0.9739	0.0139
0.9652	0.0403
0.9565	0.0764
0.9478	0.1028
0.9391	0.1403
0.9303	0.1750
0.9216	0.2153
0.9129	0.2431
0.9042	0.2583
0.8955	0.2681
0.8868	0.2833
0.8781	0.3056
0.8694	0.3250
0.8607	0.3472
0.8520	0.3708
0.8433	0.3958
0.8346	0.4139
0.8259	0.4431
0.8172	0.4542
0.8085	0.4847

0.7233	0.7204
0.7130	0.7406
0.7028	0.7648
0.6925	0.8065
0.6823	0.8616
0.6720	0.9167
0.6618	0.9516
0.6515	0.9745
0.6413	0.9906
0.6310	1.0000
0.0000	1.0000

PERIOD NO. 10: JULY

RATIO PERIOD/ANNUAL
PEAK............: 0.8512
NUMBER OF HOURS: 744

LOAD DURATION CURVE. (pu).

LOAD	DURATION
1.0000	0.0000
0.9909	0.0027
0.9818	0.0081
0.9727	0.0202
0.9636	0.0403
0.9545	0.0820
0.9453	0.1384
0.9362	0.1734
0.9271	0.1989
0.9180	0.2151
0.9089	0.2272
0.8998	0.2513
0.8907	0.2608
0.8816	0.2715
0.8725	0.2849
0.8633	0.3011
0.8542	0.3226
0.8451	0.3468
0.8360	0.3710
0.8269	0.3965
0.8178	0.4180
0.8087	0.4435
0.7996	0.4718

0.7997	0.5181
0.7910	0.5542
0.7823	0.5819
0.7736	0.6125
0.7649	0.6500
0.7562	0.6625
0.7475	0.6861
0.7388	0.7083
0.7301	0.7264
0.7214	0.7528
0.7127	0.7861
0.7040	0.8264
0.6953	0.8611
0.6866	0.9097
0.6778	0.9417
0.6343	1.0000
0.0000	1.0000

PERIOD NO. 11: AUGUST

RATIO PERIOD/ANNUAL
PEAK............: 0.8382
NUMBER OF HOURS: 744

LOAD DURATION CURVE. (pu).

LOAD	DURATION
1.0000	0.0000
0.9911	0.0202
0.9822	0.0457
0.9733	0.0699
0.9644	0.0954
0.9555	0.1183
0.9466	0.1626
0.9377	0.1935
0.9288	0.2231
0.9199	0.2406
0.9110	0.2675
0.9021	0.2849
0.8932	0.3078
0.8843	0.3414
0.8754	0.3589
0.8665	0.3790
0.8576	0.4005
0.8487	0.4180
0.8398	0.4409

0.7905	0.5040
0.7813	0.5457
0.7722	0.5699
0.7631	0.6022
0.7540	0.6344
0.7449	0.6599
0.7358	0.6801
0.7267	0.6976
0.7176	0.7191
0.7085	0.7339
0.6994	0.7634
0.6902	0.8051
0.6720	0.9005
0.6538	0.9718
0.6447	0.9839
0.5991	1.0000
0.0000	1.0000

PERIOD NO. 12: SEPTEMBER

RATIO PERIOD/ANNUAL
PEAK............: 0.8196
NUMBER OF HOURS: 720

LOAD DURATION CURVE. (pu).

LOAD	DURATION
1.0000	0.0000
0.9914	0.0014
0.9828	0.0139
0.9743	0.0194
0.9657	0.0347
0.9571	0.0639
0.9485	0.1194
0.9399	0.1569
0.9314	0.2292
0.9228	0.2722
0.9142	0.3056
0.9056	0.3264
0.8970	0.3556
0.8885	0.3819
0.8799	0.3931
0.8713	0.4042
0.8627	0.4208
0.8541	0.4403
0.8455	0.4708

0.8309	0.4516	0.8370	0.4958
0.8220	0.4825	0.8284	0.5139
0.8131	0.5121	0.8198	0.5472
0.8042	0.5376	0.8112	0.5625
0.7953	0.5565	0.8026	0.5806
0.7864	0.5874	0.7941	0.6097
0.7775	0.6223	0.7855	0.6264
0.7686	0.6492	0.7769	0.6528
0.7597	0.6680	0.7683	0.6764
0.7508	0.6828	0.7597	0.6889
0.7419	0.6976	0.7512	0.7083
0.7330	0.7164	0.7426	0.7208
0.7241	0.7460	0.7340	0.7431
0.7152	0.7728	0.7254	0.7694
0.7063	0.8091	0.7168	0.8097
0.6974	0.8481	0.7082	0.8667
0.6885	0.8777	0.6997	0.9264
0.6707	0.9610	0.6911	0.9542
0.6528	0.9973	0.6739	0.9833
0.6439	1.0000	0.6568	1.0000
0.0000	1.0000	0.0000	1.0000

SASKATCHEWAN POWER ELECTRIC SYSTEM

SASKATCHEWAN GENERATING SYSTEM 1992 - 1996

UNIT NAME	OUTPUT (MW)	FOR (pu)	POR (pu)	MAINT. CLASS (MW)
BNDRYDAM 1	62.	0.1472	.0577	100.
BNDRYDAM 2	62.	0.1472	.0577	100.
BNDRYDAM 3	139.	0.0929	.0577	100.
BNDRYDAM 4	139.	0.0929	.0577	100.
BNDRYDAM 5	139.	0.0929	.0577	100.
BNDRYDAM 6	273.	0.0708	.0769	275.
POPRIV 1	275.	0.066	.0769	275.
POPRIV 2	272.	0.066	.0769	275.
QEENELIZ 1	62.	0.0254	.0577	50.
QEENELIZ 2	62.	0.0798	.0577	50.
QEENELIZ 3	95.	0.0122	.0577	100.
LANDIS	60.	0.1432	.0385	50.
SUCCES 1	10.	0.0792	.0385	10.
SUCCES 2	10.	0.0792	.0385	10.
SUCCES 3	10.	0.0792	.0385	10.
MDOWLAKE	46.	0.1432	.0385	50.
ISLFALLS 1	12.	0.0021	.0058	10.
ISLFALLS 2	12.	0.0021	.0058	10.
ISLFALLS 3	12.	0.0021	.0058	10.
ISLFALLS 4	15.	0.0021	.0048	10.
ISLFALLS 5	15.	0.0021	.0058	10.
ISLFALLS 6	15.	0.0021	.0058	10.
ISLFALLS 7	15.	0.0021	.0058	10.
GAS TURBINE 1	50.	0.1413	.0385	50.
GAS TURBINE 2	100.	0.1429	.0385	100.
GAS TURBINE 3	100.	0.1429	.0385	100.
GAS TURBINE 4	100.	0.1429	.0385	100.
GAS TURBINE 5	100.	0.1429	.0385	100.
SHAND 1	279.	0.066	.0769	275.
SHAND 2 (INSTALLED IN 1994)	279.	0.066	.0769	275.

HYDROELECTRIC GENERATION

PERIOD	MINIMUM OUTPUT (MW)	MAXIMUM OUTPUT (MW)	ENERGY GENERATION (MWh)
OCT	32.0	726	195000.
NOV	32.0	726	185000.
DEC	32.0	719	240000.
JAN	32.0	650	297000.
FEB	32.0	701	260000.
MAR	32.0	684	242000.
APR	32.0	687	257000.
MAY	32.0	695	269000.
JUN	32.0	707	301000.
JUL	32.0	723	287000.
AUG	32.0	726	238000.
SEP	32.0	726	193000.

LOAD CHARACTERISTICS

FORECAST PEAK DEMAND

YEAR	PEAK (MW)
1992	2875
1993	2938
1994	3005
1995	3065
1996	3124

PERIOD NO. 1: OCTOBER

RATIO PERIOD/ANNUAL
PEAK...........: 0.8544
NUMBER OF HOURS: 744

LOAD DURATION CURVE. (pu).

LOAD	DURATION
1.0000	0.0000
0.9750	0.0040
0.9500	0.0121
0.9250	0.0215
0.9000	0.0376
0.8750	0.0725
0.8500	0.1169
0.8250	0.1653
0.8000	0.2325
0.7750	0.3024
0.7500	0.3871
0.7250	0.4866
0.7000	0.5511
0.6750	0.6156
0.6500	0.6828
0.6250	0.7594
0.6000	0.7997
0.5750	0.8535
0.5500	0.9126
0.5250	0.9718
0.5000	0.9879
0.4750	0.9973
0.4500	1.0000
0.0	1.0000

PERIOD NO. 2: NOVEMBER

RATIO PERIOD/ANNUAL
PEAK...........: 0.9169
NUMBER OF HOURS: 720

LOAD DURATION CURVE. (pu).

LOAD	DURATION
1.0000	0.0000
0.9750	0.0028
0.9500	0.0125
0.9250	0.0298
0.9000	0.0639
0.8750	0.1222
0.8500	0.2056
0.8250	0.2861
0.8000	0.3917
0.7750	0.4861
0.7500	0.5583
0.7250	0.6500
0.7000	0.7208
0.6750	0.7903
0.6500	0.8625
0.6250	0.9403
0.6000	0.9833
0.5750	1.0000
0.0	1.0000

PERIOD NO. 3: DECEMBER

RATIO PERIOD/ANNUAL
PEAK...........: 1
NUMBER OF HOURS: 744

LOAD DURATION CURVE. (pu).

LOAD	DURATION
1.0000	0.0000
0.9500	0.0067

PERIOD NO. 4: JANUARY

RATIO PERIOD/ANNUAL
PEAK...........: 0.9272
NUMBER OF HOURS: 744

LOAD DURATION CURVE. (pu).

LOAD	DURATION
1.0000	0.0000
0.9750	0.0134

0.9250	0.0188
0.9000	0.0417
0.8750	0.0780
0.8500	0.1425
0.8250	0.2419
0.8000	0.3401
0.7750	0.4328
0.7500	0.5296
0.7250	0.6210
0.7000	0.6962
0.6750	0.8172
0.6500	0.8777
0.6250	0.9180
0.6000	0.9637
0.5750	0.9812
0.5500	0.9919
0.5250	0.9987
0.5000	1.0000
0.0	1.0000

PERIOD NO. 5: FEBRUARY

RATIO PERIOD/ANNUAL
PEAK............: 0.8082
NUMBER OF HOURS: 672

LOAD DURATION CURVE. (pu).

LOAD	DURATION
1.0000	0.0000
0.9750	0.0043
0.9500	0.0187
0.9250	0.0661
0.9000	0.1753
0.8750	0.3247
0.8500	0.4325
0.8250	0.5187
0.8000	0.5833
0.7750	0.6422
0.7500	0.6983
0.7250	0.7615
0.7000	0.8362
0.6750	0.9296
0.6500	0.9914
0.6250	1.0000
0.0	1.0000

0.9500	0.0323
0.9250	0.0753
0.9000	0.1331
0.8750	0.1962
0.8500	0.2823
0.8250	0.3414
0.8000	0.4194
0.7750	0.5175
0.7500	0.6116
0.7250	0.6949
0.7000	0.7608
0.6750	0.8212
0.6500	0.8535
0.6250	0.9032
0.6000	0.9543
0.5750	0.9960
0.5500	1.0000
0.0	1.0000

PERIOD NO. 6: MARCH

RATIO PERIOD/ANNUAL
PEAK............: 0.838
NUMBER OF HOURS: 744

LOAD DURATION CURVE. (pu).

LOAD	DURATION
1.0000	0.0000
0.9750	0.0108
0.9500	0.0242
0.9250	0.0618
0.9000	0.1223
0.8750	0.1855
0.8500	0.2581
0.8250	0.3468
0.8000	0.4651
0.7750	0.5605
0.7500	0.6532
0.7250	0.7392
0.7000	0.7970
0.6750	0.8401
0.6500	0.8898
0.6250	0.9409
0.6000	0.9718

0.5750	1.0000

PERIOD NO. 7: APRIL

RATIO PERIOD/ANNUAL
PEAK............: 0.721
NUMBER OF HOURS: 720

LOAD DURATION CURVE. (pu).

LOAD	DURATION
1.0000	0.0000
0.9750	0.0097
0.9500	0.0278
0.9250	0.0653
0.9000	0.1431
0.8750	0.2319
0.8500	0.3236
0.8250	0.4000
0.8000	0.4750
0.7750	0.5292
0.7500	0.5889
0.7250	0.6403
0.7000	0.7069
0.6750	0.7903
0.6500	0.8736
0.6250	0.9306
0.6000	0.9708
0.5750	0.9819
0.5500	1.0000
0.0	1.0000

PERIOD NO. 8: MAY

RATIO PERIOD/ANNUAL
PEAK............: 0.7395
NUMBER OF HOURS: 744

LOAD DURATION CURVE. (pu).

LOAD	DURATION
1.0000	0.0000
0.9750	0.0027
0.9500	0.0067
0.9250	0.0309
0.9000	0.0645
0.8750	0.1546
0.8500	0.2460
0.8250	0.3548
0.8000	0.4315
0.7750	0.5121
0.7500	0.5766
0.7250	0.6210
0.7000	0.6667
0.6750	0.7352
0.6500	0.8185
0.6250	0.9059
0.6000	0.9503
0.5750	0.9879
0.5500	1.0000
0.0	1.0000

PERIOD NO. 9: JUNE

RATIO PERIOD/ANNUAL
PEAK............: 0.7477
NUMBER OF HOURS: 720

LOAD DURATION CURVE. (pu).

LOAD	DURATION
1.0000	0.0000
0.9750	0.0028
0.9500	0.0153
0.9250	0.0403
0.9000	0.0903

PERIOD NO. 10: JULY

RATIO PERIOD/ANNUAL
PEAK............: 0.7736
NUMBER OF HOURS: 744

LOAD DURATION CURVE. (pu).

LOAD	DURATION
1.0000	0.0000
0.9750	0.0027
0.9500	0.0040
0.9250	0.0108
0.9000	0.0417

0.8750	0.1556
0.8500	0.2361
0.8250	0.3194
0.8000	0.3889
0.7750	0.4514
0.7500	0.5181
0.7250	0.5889
0.7000	0.6458
0.6750	0.6958
0.6500	0.7444
0.6250	0.8028
0.6000	0.8833
0.5750	0.9486
0.5500	1.0000
0.0	1.0000

PERIOD NO. 11: AUGUST

RATIO PERIOD/ANNUAL
PEAK............: 0.7658
NUMBER OF HOURS: 744

LOAD DURATION CURVE. (pu).

LOAD	DURATION
1.0000	0.0000
0.9500	0.0040
0.9250	0.0215
0.9000	0.0793
0.8750	0.1277
0.8500	0.2070
0.8250	0.2863
0.8000	0.3911
0.7750	0.4906
0.7500	0.5497
0.7250	0.6035
0.7000	0.6411
0.6750	0.6694
0.6500	0.7137
0.6250	0.7621
0.6000	0.8414
0.5750	0.9247
0.5500	0.9812
0.5250	1.0000
0.0	1.0000

0.8750	0.0981
0.8500	0.1707
0.8250	0.2527
0.8000	0.3333
0.7750	0.3978
0.7500	0.4489
0.7250	0.4933
0.7000	0.5538
0.6750	0.6142
0.6500	0.6667
0.6250	0.7218
0.6000	0.7823
0.5750	0.8535
0.5500	0.9234
0.5250	0.9624
0.5000	1.0000

PERIOD NO. 12: SEPTEMBER

RATIO PERIOD/ANNUAL
PEAK............: 0.7287
NUMBER OF HOURS: 720

LOAD DURATION CURVE. (pu).

LOAD	DURATION
1.0000	0.0000
0.9750	0.0056
0.9500	0.0139
0.9250	0.0514
0.9000	0.1236
0.8750	0.2000
0.8500	0.2917
0.8250	0.3750
0.8000	0.4569
0.7750	0.5264
0.7500	0.5403
0.7250	0.6472
0.7000	0.6806
0.6750	0.7375
0.6500	0.8042
0.6250	0.8875
0.6000	0.9626
0.5750	1.0000
0.0	1.0000

BRITISH COLUMBIA ELECTRIC SYSTEM

BRITISH COLUMBIA GENERATING SYSTEM 1992 - 1996				
UNIT NAME	OUTPUT (MW)	FOR (pu)	POR (pu)	MAINT. CLASS (MW)
ALOUETTE	9.	0.01	.0384	10.
ASH RIVER	27.	0.01	.0384	30.
BRDGE RVR1	53.	0.01	.0384	50.
BRDGE RVR2	53.	0.01	.0384	50.
BRDGE RVR3	53.	0.01	.0384	50.
BRDGE RVR4	53.	0.01	.0384	50.
BRDGE RVR5	72.	0.01	.0384	50.
BRDGE RVR6	72.	0.01	.0384	50.
BRDGE RVR7	72.	0.01	.0384	50.
BRDGE RVR8	72.	0.01	.0384	50.
BURRARD 1	150.	0.2	.0822	150.
BURRARD 2	150.	0.2	.0822	150.
BURRARD 3	150.	0.2	.0822	150.
BURRARD 4	150.	0.2	.0822	150.
BURRARD 5	150.	0.2	.0822	150.
BURRARD 6	150.	0.2	.0822	150.
CHEACAMUS1	72.	0.01	.0384	50.
CHEACAMUS2	72.	0.01	.0384	50.
CLOWHOM	30.	0.01	.0384	30.
GM SHRUM 1	261.	0.02	.0767	270.
GM SHRUM 2	261.	0.02	.0767	270.
GM SHRUM 3	261.	0.02	.0767	270.
GM SHRUM 4	261.	0.02	.0767	270.
GM SHRUM 5	261.	0.02	.0767	270.
GM SHRUM 6	275.	0.02	.0767	270.
GM SHRUM 7	275.	0.02	.0767	270.
GM SHRUM 8	275.	0.02	.0767	270.
GM SHRUM 9	275.	0.02	.0767	270.
GM SHRUM10	275.	0.02	.0767	270.
JOHN HART1	21.	0.01	.0384	20.
JOHN HART2	21.	0.01	.0384	20.
JOHN HART3	21.	0.01	.0384	20.
JOHN HART4	21.	0.01	.0384	20.
JOHN HART5	21.	0.01	.0384	20.
JOHN HART6	21.	0.01	.0384	20.

BRITISH COLUMBIA GENERATING SYSTEM 1992 - 1996 (cont'd)				
UNIT NAME	OUTPUT (MW)	FOR (pu)	POR (pu)	MAINT. CLASS (MW)
JORDANRIVR	170.	0.02	.0384	150.
KOOTENAY 1	132.	0.02	.0384	150.
KOOTENAY 2	132.	0.02	.0384	150.
KOOTENAY 3	132.	0.02	.0384	150.
KOOTENAY 4	132.	0.02	.0384	150.
KEOGH 1	54.	0.1	.0384	50.
KEOGH 2	40.	0.1	.0384	50.
LA JOIE	22.	0.01	.0384	20.
BUNTZEN 1	9.	0.01	.0384	10.
BUNTZEN 2	9.	0.01	.0384	10.
BUNTZEN 3	9.	0.01	.0384	10.
BUNTZEN 4	55.	0.01	.0384	50.
LADORE 1	24.	0.01	.0384	20.
LADORE 2	24.	0.01	.0384	20.
MICA 1	400.	0.02	.0767	400.
MICA 2	400.	0.02	.0767	400.
MICA 3	400.	0.02	.0767	400.
MICA 4	400.	0.02	.0767	400.
MISCEL. 1	5.	0.01	.0384	10.
MISCEL. 2	12.	0.01	.0384	10.
MISCEL. 3	5.	0.01	.0384	10.
MISCEL. 4	5.	0.01	.0384	10.
MISCEL. 5	4.	0.01	.0384	10.
MISCEL. 6	8.	0.01	.0384	10.
PEACECAN 1	175.	0.02	.0767	150.
PEACECAN 2	175.	0.02	.0767	150.
PEACECAN 3	175.	0.02	.0767	150.
PEACECAN 4	175.	0.02	.0767	150.
PUNTLEDGE	24.	0.01	.0384	20.
REVELSTK 1	450.	0.02	.0767	400.
REVELSTK 2	450.	0.02	.0767	400.
REVELSTK 3	450.	0.02	.0767	400.
REVELSTK 4	450.	0.02	.0767	400.
RUPERT 1	33.	0.1	.0384	30.
RUPERT 2	33.	0.1	.0384	30.
RUSKIN 1	35.	0.01	.0384	30.
RUSKIN 2	35.	0.01	.0384	30.
RUSKIN 3	35.	0.01	.0384	30.

BRITISH COLUMBIA GENERATING SYSTEM 1992 - 1996 (cont'd)

UNIT NAME	OUTPUT (MW)	FOR (pu)	POR (pu)	MAINT. CLASS (MW)
STRATHCN 1	30.	0.01	.0384	30.
STRATHCN 2	30.	0.01	.0384	30.
STVEFALL 1	11.	0.01	.0384	10.
STVEFALL 2	11.	0.01	.0384	10.
STVEFALL 3	11.	0.01	.0384	10.
STVEFALL 4	11.	0.01	.0384	10.
STVEFALL 5	11.	0.01	.0384	10.
SETON	42.	0.01	.0384	50.
SEVNMILE 1	176.	0.02	.0575	150.
SEVNMILE 2	176.	0.02	.0575	150.
SEVNMILE 3	176.	0.02	.0575	150.
SEVNMILE 4	176.	0.02	.0575	150.
WALEACH	64.	0.01	.0384	50.
WALATSHAN	50.	0.01	.0384	50.

LOAD CHARACTERISTICS

FORECAST PEAK DEMAND

YEAR	PEAK (MW)
1992	7730
1993	7820
1994	8000
1995	8140
1996	8320

PERIOD	RATIO PERIOD/ANNUAL PEAK	NUMBER OF HOURS
PERIOD NO. 1: OCTOBER	0.891	744
PERIOD NO. 2: NOVEMBER	0.9653	720
PERIOD NO. 3: DECEMBER	1	744
PERIOD NO. 4: JANUARY	0.9624	744
PERIOD NO. 5: FEBRUARY	0.9547	672
PERIOD NO. 6: MARCH	0.8792	744
PERIOD NO. 7: APRIL	0.8282	720
PERIOD NO. 8: MAY	0.7907	744

PERIOD NO. 9: JUNE	
RATIO PERIOD/ANNUAL	
PEAK............:	0.786
NUMBER OF HOURS:	720

PERIOD NO. 10: JULY	
RATIO PERIOD/ANNUAL	
PEAK............:	0.7522
NUMBER OF HOURS:	744

PERIOD NO. 11: AUGUST	
RATIO PERIOD/ANNUAL	
PEAK............:	0.7596
NUMBER OF HOURS:	744

PERIOD NO. 12: SEPTEMBER	
RATIO PERIOD/ANNUAL	
PEAK............:	0.8123
NUMBER OF HOURS:	720

Note: Load Durations Curves were not used, since hydroelectric plants were modelled as thermal plants.