OPERATING CONSIDERATIONS IN RELIABILITY MODELING OF INTERCONNECTED SYSTEMS - AN ANALYTICAL APPROACH

C. Singh, A.D. Patton, A. Lago-Gonzalez
Texas A&M University

A.R. Vojdani, G. Gross
Pacific Gas & Electric CO.

F.F. Wu
University of California, Berkeley

N.J. Balu
EPRI

Abstract: This paper presents an analytical method which can incorporate both operating considerations and interconnection constraints in multiarea reliability evaluation. The model, called OPRINS, is a substantial extension and generalization of concepts contained in the single area OPCON model and the decomposition-simulation approach for multiarea reliability evaluation. These new techniques have been implemented in two computer programs called OPRINS-A and OPRINS-P for the study of interconnected systems operating in "area" or "pool" modes for commitment of generating units. Some system studies are described which compare the results obtained from this approach with the comparative sequential simulation models.

INTRODUCTION

The traditionally-used methods for generating capacity reliability evaluation are idealized and do not explicitly consider many unit and system operating considerations which influence system reliability. These methods have been widely used in the utility industry for generation system reliability evaluation. In recent years, there has been an agressive move in utilities to implement a set of new alternatives, such as load management programs, conservation measures and intermittent resources as a substitute for capacity expansion. In order to evaluate the impact of such alternatives on generation system reliability, there is a need for reliability methods which can explicitly incorporate various operating considerations and interconnection policies. The OPCON model [1-3], intended for single area reliability evaluation, is capable of incorporating the effects of many operating considerations such as unit duty cycles as influenced by load, unit outage postponability and startup delays. This model, however, can not represent the constraints imposed by the transmission system connecting the generation sources and the load points. This paper now presents the OPRINS reliability evaluation methodology [4] which can incorporate both the operating considerations and the interconnection constraints in multi-area reliability evaluation.

MATHEMATICAL BACKGROUND

The method used in the OPRINS approach to the solution of the interconnected system problem is based on the decomposition-simulation [5] approach which is an extension of the state-space decomposition method [6]. This section gives a brief review of this method.

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System Representation

The interconnected system, in this approach, is modelled by a probabilistic flow network with capacitated arcs. Figure 1 presents an example of the model for a 2-area system. The role of the various arcs is as follows.

- An arc from source node s to area i represents the discrete capacity states that the generation in area i can assume.
- An arc between nodes i and j represents the discrete capacity states of the transmission link between areas i and j.
- An arc between node i and the terminal node t represents the load in area i. This model therefore assumes a fixed load in each area. The method of incorporating the variation of load is described later.

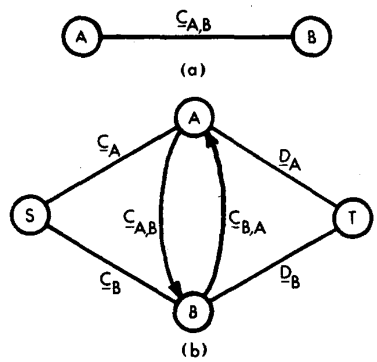

Figure 1. An interconnected two-area system (a) and its flow network representation (b)

In essence, the interconnected system is represented by arcs with discrete capacities. The capacity of arc i may be denoted by random variable $\underline{c_i}$ such that

$$p_{ij} = P_r\{\underline{c_i} = c_{ij}\} \text{ with } j = 1, 2, \ldots \ell_i. \qquad (1)$$

Here ℓ_i is the number of distinct capacity levels for arc i. When each random variable $\underline{c_i}$ takes a value, say c_{ix_i}, this corresponds to a system state

$$\underline{x} = (x_1, x_2, \ldots x_n)$$

The collection of these system states forms the state space H of the multiarea power system model.

Max Flow Calculation

For classifying a system state $\underline{x}$ as load loss or otherwise, the maximal flow from source to sink needs to be found. This

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can be achieved by using the labeling algorithms [7]. The transportation model for multi-area power system is adequate for dealing with the real power flows but it can not represent the voltage variations or reactive power flow. For each maximal flow, there is a minimal cut consisting of arcs whose capacities limit the flow. There may be more than one min cut corresponding to a max flow. Therefore increasing the capacity of arcs in a minimal cut may not always increase the value of maximal flow as some other minimal cut may become the limiting factor. It is, however, possible to identify [5,7] sets of nodes $N_s^*(\underline{x})$ and $N_t^*(\underline{x})$ such that the arcs joining the nodes in these two sets are common to all the minimal cuts and therefore increasing their capacity results in increased value of max flow. These two sets $N_s^*(\underline{x})$ and $N_t^*(\underline{x})$ contain the s and t nodes respectively. The concept of these sets is used in this approach for identifying the need rates of units.

Decomposition-Simulation Approach

The decomposition procedure consists of first classifying the entire state space into sets of acceptable (no loss of load) and unacceptable (loss of load) states. The remaining state space is termed unclassified. The unclassified states are further decomposed into sets of acceptable, unacceptable and unclassified states. The sets of unacceptable states can be further classified into sets having the same area load loss characteristics. If the process of decomposition were to be continued, the entire state space will be exhaustively classified into sets of acceptable states, and sets of unacceptable states with identical area load loss characteristics. In practice after a certain stage, the probability of sets generated is quite low and exhaustive decomposition procedure is stopped when the probability of sets generated is below a threshold value. The contribution of the residual unclassified sets to the reliability indices is estimated by using a Monte Carlo method to sample states from these sets.

At a given stage of the decomposition phase, there exist the following types of subsets.

- sets of acceptable states, A_k
- sets of system loss of load states L_k
- sets of unclassified states U_k: These sets contain states which may be acceptable or loss of load.
- sets of loss of load states with identical area loss of load characteristics, B_k. These sets are obtained by decomposition of sets L_k and this decomposition depends on the loss of load sharing policy.

It should be noted that if the decomposition was performed exhaustively, then there will be only A_k and B_k sets.

Contributions to indices from the decomposition phase

For a given set of area loads, the system and area loss of load probabilities can be readily obtained by summing the probabilities of the appropriate L_k and B_k subsets. Calculation of frequency indices involves calculating the frequency of encountering appropriate B_k's from A_i's. The frequency of transition from A_i to B_k, which are disjoint, can be obtained as follows.

Let

$$\alpha^j = \text{set of states in which component j exists in } A_i$$
$$\beta^j = \text{set of states in which component j exists in } B_l$$
$$A_i^j X \alpha^j = A_i$$
$$B_l^j X \beta^j = B_l$$

and

$$I^j = A_i^j \cap B_l^j$$

Then for a direct transition to exist from A_i to B_l, the following conditions need to be satisfied:

(a) I^j is a null set for all j except j=k

(b) there is a single step transition between α^k and β^k.

Then

$$F(A_i \rightarrow B_l) = P(I^k)F(\alpha^k \rightarrow \beta^k) \tag{2}$$

where

$F(A_i \rightarrow B_l)$ = Frequency of transition from A_i to B_l

and

$F(\alpha^k \rightarrow \beta^k)$ = Frequency of component k transitioning from states $\epsilon\alpha^k$ to states $\epsilon\beta^k$.

From equation (2), it can be seen that for the frequency computation, area generation models of the following form are required:

$P(X)$ = Probability of capacity being equal to X MW

$F(X, Y)$ = Frequency of encountering Y MW from X MW when $Y<X$.

An efficient algorithm is used in the OPRINS computer programs for developing generation models of this type. The underlying concept is described in Appendix A.

Multi-Area Load Model

An exact state multi-area load model is used. The multi-area load state $\underline{d}^i$ is a vector such that,

$$\underline{d}^i = (d_1^i, d_2^i, ..., d_N^i)$$

where

$$d_j^i = \text{load in area j in load state i.}$$

The load model is then represented by

$P(\underline{D} = \underline{d}^i)$ = Probability of load state $\underline{d}^i$

and

$F(\underline{d}^i \rightarrow \underline{d}^j)$ = Frequency of load transition from $\underline{d}^i$ to $\underline{d}^j$

In this model, each load model state is represented by a fixed load in each area. Reliability indices are calculated for each load state and then combined to give overall indices. For the frequency index, the contributions due to transiting from A & B sets in load state i to B sets in load state j are computed using equation 2. One suitable approach to deriving this load model from the hourly load data of the various areas is to use clustering algorithms used in the SAS statistical analysis package. These algorithms identify clusters of hourly load values and thus capture the correlation between area loads. A cluster i defines the load state $\underline{d}^i$ with the mean value of the area loads in this cluster defining d_j^i.

Contribution to indices from Monte Carlo Simulation Phase

The contribution to event probabilities from the Monte Carlo simulation phase is computed using the following equation:

$$P_m = \frac{n}{N} P \tag{3}$$

where

P_m = Monte Carlo contribution to the probability of the event

N = sample size

n = number of states drawn in which the event of interest occurs

P = probability of the non-decomposed set from which the sample is drawn.

For the purposes of computing the Monte Carlo phase contribution to event frequencies, the following approach has been developed and implemented. Basically the frequency contribution consists of two components, one due to generation changes and the other due to load variations.

Frequency Contribution Due to Generation Changes

Let

AN = sets of acceptable states obtained during the decomposition phase

BN = sets of loss of load states obtained during the decomposition phase

AS = acceptable states drawn during the Monte Carlo simulation phase

BS = loss of load states drawn during the Monte Carlo simulation phase

The Monte Carlo simulation phase frequency contribution due to generation results from the following types of transitions:

$AN \rightarrow BS$

$AS \rightarrow BN$

$AS \rightarrow BS$

The calculation procedure can be explained by using $AN \rightarrow BS$ transitions as an example. This frequency can be computed by equation (4).

$$\hat{f}(AN \rightarrow BU) = f(AN \rightarrow BS)\frac{\hat{P}(BU)}{P(BS)} \tag{4}$$

$\hat{f}(AN \rightarrow BU)$ = estimate of frequency of encountering unclassified loss of load states from classified acceptable states

$f(AN \rightarrow BS)$ = calculated frequency from classified acceptable states to loss of load states drawn during the Monte Carlo simulation phase

$\hat{P}(BU)$ = estimate of BU using equation (3)

$P(BS)$ = calculated probability of BS

Frequency Contributions Due to Load Changes

Here the transitions contributing to the frequency are of the following types:

$AN_i \rightarrow BS_j$

$AS_i \rightarrow BN_j$

$AS_i \rightarrow BS_j$

$BS_i \rightarrow BS_j$

$BN_i \rightarrow BS_j$

$BS_i \rightarrow BN_j$

where the subscripts refer to the load states. The calculation procedure is similar to that due to generation changes.

BASIC APPROACH

The approach which has been developed is a recursive methodology similar to the OPCON approach [1] except that interconnection constraints are taken into account. All areas are assumed to operate in "area mode" (OPRINS-A) or in the "pool mode" (OPRINS-P). In the area mode, units are committed to satisfy area requirements including any scheduled interchanges. Areas may also assist each other through emergency interchanges in the area mode of operation. In the pool mode, units are committed to satisfy pool requirements, in any area, subject to transmission limitations. The unit commitment is on pool basis and units are committed to reduce capacity deficiency in any area of the interconnection subject to transmission constraints. The notation j_I is used to denote the jth unit in the system-wide commitment priority list if that unit is located in area I. Unit j_I is committed if after considering the first j-1 units in the priority list, there is a need for unit j_I, i.e.,

(a) there is a capacity deficiency in any area in the pool, and

(b) additional generation capacity in area I can reduce the capacity deficiency in any area in the pool.

The basic steps in the proposed approach are:

Step 1: Compute the duty cycle of unit j_I, taking into consideration the system operating considerations.

Step 2: Set up the Markov model of unit j_I.

Step 3: Reduce the Markov model in Step 2 to a 2-state (or 3-state) equivalent model.

Step 4: Update the generation capacity model of area I using the unit addition algorithm.

Step 5: Repeat Steps 1-4 for each unit: after the last unit on the commitment list has been processed go to the Step 6.

Step 6: Compute the reliability indices.

Steps 2 to 4 are identical to their counterparts in the single-area OPCON scheme. As in OPCON, start-up failures, start-up delays, minimum up and down times, and the outage postponability are modelled by constructing appropiate Markov models of 2-state or 3-state units in Step 2. The datailed description of these models can be found in References 1-3. In implementing Step 1, the OPCON philosophy that the 2-state (or

3-state) equivalent Markov models constructed in Step 3 can be regarded as unit models which undergo failures and repairs independently is used. The equivalent unit models for units 1....j-1 are then used to compute the duty cycle of unit j including the network constraints. This is described in the next section. Once all the units are processed, the decomposition-simulation model [5] is used once again for computation of reliability indices in Step 6.

DUTY CYCLE CALCULATION IN OPRINS

It is assumed that in the area mode of operation, the emergency interchanges have only a minor effect on unit duty cycles and are ignored for this purpose. The unit duty cycles for the area mode of operation are thus calculated using single-area OPCON methodology. The remaining discussion of unit duty cycle calculations is for the pool mode of operation.

Definition of Unit Duty Cycle in Multi-Area Systems

The duty cycle of the jth unit in the commitment priority list can be defined in terms of the system with only the first j-1 units considered. To do this, let us define the event NEED_{j_I} (the need for unit j_I) as follows:

NEED_{j_I} There is capacity deficiency in any area in the pool, and additional generation capacity in area I can reduce the existing capacity deficiency in one or more areas in the pool.

The notation $\overline{\mathrm{NEED}}_{j_I}$ will be used to denote the complement of the event NEED_{j_I}.

The system state space prior to the commitment of unit j_I is partitioned into the two subsets S_{j_I} and $\overline{S}_{j_I}$, which represent the events NEED_{j_I} and $\overline{\mathrm{NEED}}_{j_I}$, respectively. It should be pointed out that not all the capacity deficiency states belong to $\overline{S}_{j_I}$. Only those capacity deficient states where additional generation in area I can reduce capacity deficiencies in one or more areas constitute $\overline{S}_{j_I}$. From the unit commitment model described previously it follows that the duty cycle of unit j_I can be characterized by the transition rates ρ_+ and ρ_- between the system states in S_{j_I} and system states $\overline{S}_{j_I}$.

Need and Shutdown Rates

Using the events NEED_{j_I} and $\overline{\mathrm{NEED}}_{j_I}$, the need rate ρ_+ and the shutdown rate ρ_- for unit j_I are defined to be:

$$\rho_+ = \frac{f(\mathrm{NEED}_{j_I})}{P(\overline{\mathrm{NEED}}_{j_I})} = \frac{f(\mathrm{NEED}_{j_I})}{1 - P(\mathrm{NEED}_{j_I})} \tag{5}$$

$$\rho_- = \frac{f(\overline{\mathrm{NEED}}_{j_I})}{P(\mathrm{NEED}_{j_I})} = \frac{f(\mathrm{NEED}_{j_I})}{P(\mathrm{NEED}_{j_I})} \tag{6}$$

where $f(\mathrm{NEED}_{j_I})$ and $P(\mathrm{NEED}_{j_I})$ and $P(\mathrm{NEED}_{j_I})$ are the frequency and probability, respectively, of NEED_{j_I}.

The term $f(\mathrm{NEED}_{j_I})$ can be expressed as the sum of two components:

$$f(\mathrm{NEED}_{j_I}) = f^g(\mathrm{NEED}_{j_I}) + f^l(\mathrm{NEED}_{j_I}) \tag{7}$$

where $f^g(\mathrm{NEED}_{j_I})$ and $f^l(\mathrm{NEED}_{j_I}$ are respectively the frequencies of NEED_{j_I} due to changes in generation and changes in load. Then

$$\rho_+^g = \frac{f^g(\mathrm{NEED}_{j_I})}{1 - P(\mathrm{NEED}_{j_I})} \tag{8}$$

$$\rho_+^l = \frac{f^l(\mathrm{NEED}_{j_I})}{1 - P(\mathrm{NEED}_{j_I})} \tag{9}$$

Computation of Probability and Frequency of Need

Assume that the first j-1 units have been processed and that we are to compute the need and shutdown rates for units j_I. With only the first j-1 units committed, the generation system can be assumed to be composed of j-1 2-state (or 3-state) units which are independent of one another. The Markov model for each of these units is the 2-state (or 3-state) equivalent Markov model constructed for that unit in Step 3 of the algorithm outlined. The multi-area system with j-1 2-state (or 3-state) units with independent failures/repairs can then be represented by a network flow model with probabilistic arc capacities as described earlier in the mathematical background.

Define

$E_I|\underline{d}^k =$ For a given $\underline{d}^k$, set of states in which increasing the generation capacity in area I reduces the existing capacity deficiency in the system.

Then

$$P(\mathrm{NEED}_{j_I}|\underline{d}^k) = P(E_I|\underline{d}^k) \tag{10}$$

and

$$f(\mathrm{NEED}_{j_I}|\underline{d}^k) = f(E_I|\underline{d}^k) \tag{11}$$

The quantity $f(\mathrm{NEED}_{j_I}|\underline{d}^1 \rightarrow \underline{d}^v)$ can be computed from the knowledge of $(E_I|\underline{d}^1)$ and $(E_I|\underline{d}^v)$. The set $E_I|\underline{d}^k$ can be constructed by the union of appropriate B sets. The B sets comprising $E_I|\underline{d}^k$ are those in which either the area I is capacity deficient or it belongs to $N_t^*(\underline{x})$.

COMPUTATION OF RELIABILITY INDICES

Once all the units are processed, one can proceed to the computation of the reliability indices, i.e., Step 6 of the proposed algorithm. At this point, the flow network contains generation arcs which represent the aggregation of all the equivalent unit models in the respective areas. Reliability indices such as system LOLE, each area's LOLE, EUD (Expected Unserved Demand), and $\mathrm{ITC}_{i,j}$ (Inadequate Transfer Capability from node i to j) can be computed from the decomposition simulation scheme [4]. $\mathrm{ITC}_{i,j}$ can be interpreted as the probability that a lack of power transfer capability from node i to j contributes to loss of load. In addition one can compute the joint loss-of-load probability for a subset of areas. Also, the frequency of various events such as loss-of-load in the system, in individual areas, or in a subset of areas can be computed along the lines described in [2]. In the OPRINS computer programs the indices calculated are system LOLE and FOCD (Frequency of Capacity Deficiency) and area LOLE and FOCD.

GLOBAL DECOMPOSITION

For duty cycle calculations, the probability and frequency of inadequate transfer capability need to be calculated after each unit addition. Performing the decomposition-simulation procedure from scratch, as in the basic approach, for each duty cycle computation is computationally inefficient. The global decomposition algorithm has been devised to overcome this problem.

The concept underlying Global decomposition is that the decomposition procedure depends on the state capacities and not state probabilities. If the state space were to be exhaustively decomposed, then the entire range of subsets could be obtained once. The subset probabilities could then be obtained by assigning zero probabilities to those states that are non-relizable when the subset of units under consideration is committed. When decomposition-simulation is used, the switch to Monte Carlo phase is based on the knowledge of state probabilities which are not known unless the duty cycles are computed. The Global Decomposition algorithm described below overcomes this problem.

a. Generation arcs are described by discrete capacity levels with the maximum and minimum capacities in the areas.

b. The generation system model for each area is then developed using the base-load units.

c. For a given load state $\underline{d}^j$, decomposition is performed and terminated when the probability of unclassified subsets is lower than the threshold probability for switching to the Monte Carlo phase. The results of decomposition are stored in file F_j.

d. Step c is repeated for all load states.

e. Using decomposition results from F_j, the frequency contribution due to load variations is calculated and the need and shut down rates of the next unit are calculated.

f. Set k=1.

g. Add unit k to the generation system model of the appropriate area.

h. Examine the probabilities of unclassified sets stored in F_j, using the updated probabilities and decompose further if required.

i. Calculate the need and shut down rates.

j. Set k = k+1. If all units have been considered, compute indices and stop.

k. Add unit k to the appropriate generation system model. Go to step h.

MODELING OF FIRM AND EMERGENCY INTERCHANGES

Firm Interchange Contract Model

A firm power interchange contract between two areas obligates the exporting area to deliver a certain amount of firm power to the importing area. The method used in OPRINS is a load and transmission capacity modification approach which assumes the delivery of firm power is certain. The firm power is added to the load in the exporting area and subtracted from load in the importing area. The tie line capacities are modified to reflect the flow of firm power. If contractual paths are specified, the tie line capacities on these paths are modified by substracting the power in the direction of flow. If, however, contractual paths are not specified, the flow paths can be determined using the network flow model.

Emergency Actions

In the event of any loss-of-load in the system, one of the following two emergency action policies can be represented:

- The loss sharing (LS) policy: areas share the unserved demand to the extent possible, considering transmission constraints.
- The no-loss sharing (NLS) policy: each area attempts to meet its own demand. If there is excess capacity, it is supplied to the neighboring areas according to a specific priority list.

The implementation of these two policies requires appropriate classification of B sets. The details can be found in [4].

SAMPLE SYSTEM STUDIES

Several studies have been made using the two different versions of the OPRINS program, OPRINS-A for area-mode operation and OPRINS-P for pool mode operation. Results obtained using these programs are compared with those obtained using the Monte Carlo simulation models GENAREA and GENPOOL [4]. The studies reported here were carried out on a synthetic system composed of three identical areas, 35 generating units per area. All studies using the OPRINS programs were made neglecting planned outages of generating units and treating the study year as a single time interval. These assumptions are not inherent in the OPRINS programs, but were made here for convenience. All studies were conducted using the load cycle shape of EPRI synthetic system scenario A for all areas of the sample system.

Generation System

The basic generation mix and unit commitment priority used for each area in the 35-unit per area studies is shown in Table 1. This is the reduced system E scenario from EPRI report EM-285. Basic generating unit parameters are drawn from [1].

The area peak load is 7923MW, thus making the installed reserve 30% for the 35-unit per area studies. Area spinning reserves have been assumed constant over the study year at 800 MW.

Unit Type in Priority list	Number of Units	Unit Cap., MW	Total Cap., MW
Nuclear	2	800	1600
Coal, Fossil > 500 MW	1	800	800
Coal, Fossil > 500 MW	2	600	1200
Coal, Fossil 250-499 MW	1	400	400
Coal, Fossil 100-249 MW	1	200	200
Gas, Fossil > 500 MW	1	800	800
Gas, Fossil > 500 MW	2	600	1200
Gas, Fossil 250-499 MW	2	400	800
Gas, Fossil 100-249 MW	11	200	2200
Oil, Fossil 250-499 MW	1	400	400
Oil, Fossil 100-249 MW	1	200	200
Combustion Turbine	10	50	500
			10300

Table 1. Basic Area Generation Mix

Transmission System

Transmission links between interconnected areas have been modeled using a four-capacity-state model. The basic transmission link was assumed to have a capacity of 600 Mw. The state transition rates are shown in Table 2.

State Physical Capacity, MW	State Transition Rates, hrs^{-1} To Next Higher Cap.	To Next Lower Cap.
600	-	0.005
400	0.1985	0.020
200	0.1985	0.020
0	2.9957	-

Table 2. Basic Transmission Link Model

Load Model

The peak load in each area was assumed to be 7923 MW and the spinning reserve objective in each area was 800 MW. The ten-state load model was derived from the hourly loads of each area for use in the analytical models. This load model is shown in Tables 3 and 4. The SAS statistical analysis package was used to derive the load model for the sample studies. Note, however, that the load model is an input to the OPRINS models and any desired method can be used to derive the required load model.

Results

The results are shown in Tables 5 through 8. The original load model referred to in these tables is a 10-cluster (state) load model obtained when peak in each area of the interconnected system is 7923 MW and the characteristics of the 10-state load model are as shown in Tables 3 and 4. Using the original load model, the reliability indices predicted by the analytical models are generally lower than those predicted by the simulation models. That is, the analytical models generally predict higher reliability than do the simulation models. The primary reason for this difference in predicted reliability indices seems to be the aggregation of hourly load levels into relatively few (10) load states in the load model. To explain this consider load state 10 as an example. Here, the magnitude of the load state

Load State #	Load in Each Area in Per Unit of Area Peak Load	Probability of Load State
1	.3988	0.0772
2	.4575	0.1421
3	.5045	0.1522
4	.5631	0.1114
5	.6335	0.1270
6	.6922	0.1573
7	.7508	0.1154
8	.8095	0.0579
9	.8682	0.0454
10	.9503	0.0142

Table 3. Load Values and Probabilities for Different States of the Load Model

is 0.9503 per unit of area peak load as seen in Table 3. This corresponds to 7529 MW for an area peak load of 7923 MW. This magnitude of 7529 MW is the mean value of many hourly load values in the corresponding cluster. Now consider two possible load points 7529 + x and 7529 - x in this cluster. The load value of 7529 + x would have contributed more to system unreliability than the 7529 MW mean load. Similarly, a 7529 - x load would have contributed less to system unreliability than the 7529 MW mean load. However, system loss-of-load probability and other indices increase almost exponentially as a function of load level. Therefore, the effect of averaging load levels to produce a load model with a limited number of states is to make the system appear too reliable. An alternative load model was created in which the magnitudes of all load states were adjusted upwards in the ratio of the area peak load to the magnitude of the highest load state. In this "adjusted" load model the magnitude of the highest load state is therefore equal to the area peak load of 7923 MW. The reliability indices produced by the analytical models using the "adjusted" load model are generally closer to the Monte Carlo simulation results. However, the analytical model results with the adjusted load model tend to overshoot and exceed the simulation results. It is evident, therefore, that the construction and selection of the load model for use in the analytical models is a critical issue. Accuracy could be expected to improve if the year were broken into intervals and a load model constructed for each interval. However, computer running time would increase in

From Load State #	To Load State # 1	2	3	4	5	6	7	8	9	10	Total
1		119	8	5							132
2	132		240	31							403
3		265		243	60						559
4		15	302		213	47	4				581
5		4	8	306		257	34	4			613
6			1	5	323		235	14			578
7					17	256		104	4		381
8						18	108		73		199
9								77		23	100
10									23		23
Total	132	403	559	581	613	578	381	199	100	23	

Table 4. Frequencies of Transition (per year) from one Load State to Another in the Load Model

direct proportion to the number of time intervals used.

Another modeling difference which contributes to the differences between analytical and Monte Carlo simulation results is the modeling of unplanned outage postponability beyond a weekend for base-loaded generating units. In the simulation models, generating unit outages which are postponable beyond the weekend are usually taken during low-load periods prior to expiration of the full period of postponability. However, no direct mechanism exists in the analytical models to indicate preferred times to take the postponable outages of base-loaded units since these units are scheduled for continuous operation and therefore do not have unneeded periods. Therefore, unplanned outages of base-loaded units are assumed to be taken after an expected postponement period. Presently, the analytical models assume that unplanned outages postponed beyond the weekend are taken with equal probability at any time beyond the weekend and before the end of the subsequent weekend. It is evident, therefore, that a more physically-based method needs to be developed for the modeling of postponability of base-loaded units in the analytical models.

Index	Monte Carlo	Analytical Model			
		Orig. Load	% Diff.	Adjust. Load	% Diff.
System HLOLE	14.4	5.0	-65	15.1	+4
System Freq.	4.3	0.7	-83	2.8	-35
Ave. Area HLOLE	6.1	2.6	-58	7.8	+28
Ave. Area Freq.	2.2	0.3	-84	1.4	-37

Table 5. Results for 35 Units per Area System No-Loss-Sharing, Area-Mode Operation

Index	Monte Carlo	Analytical Model			
		Orig. Load	% Diff.	Adjust. Load	% Diff.
System HLOLE	19.4	5.0	-74	15.1	-22
System Freq.	7.1	0.7	-90	2.8	-60
Ave. Area HLOLE	9.0	3.1	-68	10.4	+15
Ave. Area Freq.	3.9	0.5	-88	1.9	-50

Table 6. Results for 35 Units per Area System Loss-Sharing, Area-Mode Operation

Index	Monte Carlo	Analytical Model			
		Orig. Load	% Diff.	Adjust. Load	% Diff.
System HLOLE	3.4	2.8	-19	5.6	+66
System Freq.	1.5	0.4	-74	1.6	+9
Ave. Area HLOLE	1.4	1.4	0	2.9	+109
Ave. Area Freq.	0.6	0.2	-68	0.8	+27

Table 7. Results for 35 Units per Area System No-Loss-Sharing, Pool-Mode Operation

Index	Monte Carlo	Analytical Model			
		Orig. Load	% Diff.	Adjust. Load	% Diff.
System HLOLE	4.4	2.8	-38	5.6	+27
System Freq.	2.2	0.4	-83	1.6	-27
Ave. Area HLOLE	2.4	1.6	-34	3.5	+46
Ave. Area Freq.	1.0	0.2	-78	1.1	+5

Table 8. Results for 35 Units per Area System Loss-Sharing, Pool-Mode Operation

ComputerExecutionTime

For the studies reported here, the CPU time on a VAX 11/785 computer was 2.5 minutes for area-mode operation and 100 minutes for pool-mode operation. The execution time for pool-mode operation is substantially higher because the unit duty cycle of each unit for pool-mode is calculated using multi-area calculation where as single-area OPCON methodology is used for duty cycle calculation for area-mode. After the duty cycles have been computed, the reliability indices are, of course, computed in both cases using the multi-area model.

CONCLUSION

A new model for the calculation of reliability indices in multi-area interconnected systems with explicit recognition of operating consideration has been developed. This new model is a substantial extention and generalization of concepts contained in the OPCON model developed in [1] and of the state-space decomposition and simulation methodology presented in [5]. The new modeling concept has been implemented in programs called OPRINS-P and OPRINS-A which are dimensioned for study of interconnected systems with up to 10 areas and operating in the pool or area-modes for commitment of generating units.

The algorithms embodied in the OPRINS programs are general in nature and are not restricted to any particular number of areas in an interconnected system. The computer program has been dimensioned to handle up to ten areas at present. However, the computation times of the programs, and in particular, OPRINS-P which computes unit duty cycles based on system-wide conditions, increase rapidly with increasing numbers of areas. Therefore, the OPRINS models for pool-mode as presently coded seem to be practically limited to study of systems with three or four areas by computer time considerations. The increase in computer time depends both on the number of areas as well as interconnections. It is hard to give any formula for computer time as a function of number of areas but our experience suggests that an almost linear relationship can be expected.

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APPENDIX A

Generation System Model

P(X) = Probability of capacity being equal to X MW
F(X,Y) = Frequency of encountering Y MW from X MW when Y<X.

An efficient algorithm for this purpose has been developed and implemented in the OPRINS program. The underlying concept is explained below for a three state unit being added. Let

PC(V) = Probability of the unit capacity equal to V MW.
FC(V,W) = Frequency of unit transition from capacity V to capacity W.
C,D = Capacity of the unit in up and derated states respectively.

Then denoting the probability and frequency after unit addition by a prime,

$$P'(X) = P(X-C)PC(C) + P(X-D)PC(D) + P(X)PC(0) \tag{A.1}$$

and

$$F'(X,Y) = F'_g(X,Y) + F'_u(X,Y) \tag{A.2}$$

where

$F'_g(X,Y)$ = component of F'(X,Y) after unit addition due to transitions of all units except the unit being added

$$= F(X-C, Y-C)PC(C) + F(X-D, Y-D)PC(D) + F(X,Y)PC(0) \tag{A.3}$$

$F'_u(X,Y)$ = component of F'(X,Y) due to transitions of the generating unit added

$$= P(X-C)FC(C,0)I_1 + P(X-C)FC(C,D)I_2 + P(X-D)FC(D,0)I_3 \tag{A.4}$$

where I_1, I_2, I_3 are zero unless

$I_1 = 1$ if XY = C

$I_2 = 1$ if X-Y= C-D

and

$I_3 = 1$ if X-Y= D

If the number of generation states is n, then the number of possible pairs for frequency calculations is $n^2/2$. However, it should be remembered since only direct transitions from X to Y contribute to F(X,Y) that F(X,Y) is zero if (X-Y)> the capacity of the largest unit in the generation system. Therefore the number of possible pairs for frequency calculation can be reduced to

$$(n)(CMAX/INC)$$

where

CMAX = capacity of largest unit
INC = increment in MW for building generation system model

The actual implementation of the algorithm is done so as to minimize the storage and computational requirement.