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A SIMULATION MODEL FOR ASSESSMENT OF LARGE-SCALE POWER SYSTEM RELIABILITY

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ABSTRACT: This paper describes research on the applicability of Monte Carlo simulation to the study of large scale power system reliability. Reliability in this context refers to the ability of the system to meet demand for electricity over time. A generalized program capable of modeling any pool of generators was developed using a modified version of the GASP-IV simulation language. The logic of this program is described and the results of two applications of the program are presented.

1. INTRODUCTION*

This is an age in which fossil fuel supplies are dwindling and energy costs are rising. The public has expressed a desire for better and cheaper service from public utilities, and in particular from electric power utilities. At the same time, Congress and the Environmental Protection Agency have restricted the use of electric power generators that burn coal, the most abundant and possible, most economic fossil fuel. To further complicate matters, the construction of nuclear power plants has been hampered by a proliferation of regulations and by public apprehension. Electric power utilities have become more concerned about their ability to meet future demand for electricity given these conflicting pressures. "Reliability" in power systems reliability is related to the ability to meet the system demand for energy often called "load". This research is concerned with the analysis of power systems from a reliability viewpoint.

Many electric utilities calculate a reliablilty index called "loss of load probability" and use it to determine the need for additional generating capacity. How well this or any other reliability index agrees with the actual system performance depends on the accuracy of the input data and the methods used for calculating reliability indices. Existing methods do not explicitly consider operating constraints such as generating unit start-up times, start-up failures, and operating flexibility, e.g., the ability to postpone unit outages. This paper presents a model called GENESIS (GENEration SImulation System) which incorporates many operating considerations and investigates the possible effect of various unit operating constraints on calculated reliability indices.

The paper includes a description of the Monte Carlo simulation model and the results of studies on (1) a synthetic system, and (2) an actual power pool. Monte Carlo simulation as applied here is the creation of an hour-by-hour artificial history of system operation (generating units failed, being repaired, load changes, etc.) using a computer model. In this approach, reliability statistics, such as how often and how long load exceeded the available capacity, can be gathered from the artificial history just as one could gather such statistics from an actual operating system. The Monte Carlo method is a very powerful tool that can incorporate complex interrelationships between many variables in the computations.

2. LITERATURE AND BACKGROUND

In 1959 Westinghouse Electric Corporation and Public Service Electric and Gas Company began a major effort to develop Monte Carlo simulation techniques for electric power capacity planning [6].

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Twenty-five engineers, mathematicians and programmers formed the operations research team responsible for the effort, which created four major types of models, the load model, the capacity model, the production costing model and the transmission planning model.

In a series of articles reprinted in a volume entitled Powercating: System Planning Through Simulation [6], Westinghouse personnel discussed what they wished to accomplish, why a simulation model is useful, and how the simulation model might work. In "Program for Planning" [7], they stated: Operational gaming was found to be a method especially suited to obtaining practical evaluation of the many random uncertainties in system behavior. It permits all variables to be taken into account, those that can be controlled and those that cannot. The method of gaming used is a combination of system analog, Monte Carlo ideas (which are statistical approaches to selecting likely combinations of random events), and human competition.

The Westinghouse group developed an operational gaming model, which includes interactions of the computer and human decision makers. In the GENESIS model decision rules are programmed so that the computer simulates the decisions of human operators. Otherwise, the above description could apply to the model presented herein.

The Westinghouse load (demand) model [4] extrapolated past trends into the future and perturbed the forecast values to arrive at a random load value to be used for a given simulation. Annual load was first developed in this fashion, then monthly and daily peak loads were similarly developed which were consistent with annual load. The GENESIS model does not forecast load; rather load data (actual or forecast) is furnished to the model as input data. The Westinghouse load model is cited here because it represents on way in which long range load forecasting could be incorporated as an extension to the GENESIS model.

A concise description of how the Westinghouse model operated is given in a three part series entitled "Mathematical Models for Use in the Simulation of Power Generation Outages" [1,2,3]. First, a string of successive put times and down times were generated using forced outage rates and assuming that the lengths of successive up times, successive down times, and successive up and down times were independent of each other. Then this string of events was adjusted to reflect planned outages, maintenance outages, and economy outages. If a thermal unit had two or more types of outages scheduled to occur in close proximity, outages are combined when possible. The load cycle created in the load model was then adjusted by treating operating hours of hydroelectric units as reductions in load. For pumped storage units, a pumping load was added during off-peak periods. The net effect of this load adjustment was to reduce peak load and raise off-peak load. By combining the operating "histories" of individual units, day by day capacity available was determined. Daily margins could then be found by subtracting the load history from the operating history.

In general, the Westinghouse approach was far more aggregated than the GENESIS model. Operating realities such as starting delay, starting failure, outage postponability, and forced deviations from unit commitment priority are all hidden in the adjustments made to unit forced outage histories. There are however, two features of the Westinghouse model not appearing in the present model which could benefit the present effort. First, the present model does not use hydroelectric units specifically to meet peak loads of short duration. Second, when a random outage occured in the vicinity of a planned outage the Westinghouse model combined the two into a single outage; the GENESIS model lacks this capability.

In summation, the GENESIS model presented herein represents a revival of an effort begun 20 years ago at Westinghouse. Westinghouse personnel, realizing the limitations of analytic models for considering operating realities of electric utilities, attempted to model these realities using Monte Carlo simulation techniques, but found that 1960 generation computers and simulation techniques were insufficient for the task. Using the GENESIS model, this study is directed at determining whether modern computers and simulation techniques permit the efficient modeling of these same realities.

The abandonment of the Westinghouse effort apparently created an attitude among North American power systems modelers that simulation was not an effective tool for their studies. At any rate, there was virtually no use of simulation to model electric power system reliability on this continent between 1964 and 1978. "The position often taken by experts on this continent is that simulation requires too much computing time in most applications and, therefore, it should not be used unless absolutely necessary" [11]. Endrenyi, Wang, and Wilson [11] point out that the technique has been successfully applied to power system reliability modeling in Europe and stated in March, 1978 that "it appears desirable to further explore the ways and means by which this technique can be adapted to the needs of power system reliability evaluation" [11].

Endrenyi, Wang, and Wilson [11] present a simple model, having only two generator states (operating, failed) exponential state residence times, and identical daily load cycles. Fifty-four thermal units were simulated. Generators were run continuously rather than being cycled, the postponability of outages is not mentioned, startup times and startup failures were apparently not considered in the model. Periodic overhaul was not discussed. This paper was presented at a power system reliability workshop sponsored by the Electric Power Research Institute in March, 1978 and appears to represent the state of the art on this continent as of that time.

Most of the recent power system reliability simulation effort has been done in Europe [11]. Some European countries have relied upon their water resources for electricity production to a much larger extent than the United States has. A feature of hydroelectric generators is that water is not always available to run them. Present analytic models of power reliability are not able to consider the availability of energy to run the generators except under an unrealistic assumption that energy shortages occur independently on each generator. Because hydroelectric units comprise a relatively large proportion of certian European power systems, the Europeans have had to make use of Monte Carlo simulation for some types of reliability analysis. These models tend to emphasize the modeling of water availability and to have simplified treatment of many operational considerations for thermal units such as startup failure and delays, outage postponability, etc.

In most of the United States hydroelectric units are only a small portion of total power generating capacity, although there are exceptions such as the Pacific Northwest. Thus the availability of energy to operate generators is presently less important in the United States than it is in parts of Europe. Energy availability may become increasingly important as fossil fuel reserves are exhausted. In developing power system reliability models in the United States primary emphasis has been placed on proper modeling of operating considerations, although need for further study of energy availability has been noted. Several European studies have been scrutinized, but these studies have not been used as prototypes for the modeling of power systems in North America.

Manzoni and Salvaderi [14] recently presented an overview of reliability evaluation at ENEL (Ente Nazionale per l'Energia Elettrica, Italy).

> For the long-term optimization of generating systems, when transmission can be disregarded, ENEL developed computing programs based on direct analytic methods. For the evaluation of system reliability including transmission and generation and for the optimum choice of peak-shaving generation mix including storage plant, as well (as) for the optimization of the basic characteristics of system 'components' recourse has been had to simulation methods of the Monte Carlo type.

The most commonly reported European models are broader in scope than the present model in that they consider the transmission system. Noferi and Paris [16] report such a system in which a week is randomly selected for simulation. Generating units are than randomly assigned to a failed state using outage rates assumed to be constant over the year. This assumption, of course, ignores precisely those operating realities included in the present model.

This brief review is not intended to be a comprehensive review of European power simulation literature, but rather to demonstrate the fundamental differences between other models and the present model. Several papers typifiying European power systems modeling were presented to a recent international conference. Models in use in France are reported by Meslier [15] and by Dodu and Merlin [8]. Fagerberg [12] presents a Norwgian model for hydroelectric plants. Insigna, Invernizzi, Manzoni, Panichelli, Salvaderi [13] report on recent work in Italy.

3. MODELING PROCEDURES AND ASSUMPTIONS

This section provides a general description of the GENESIS model which is based in a modified version of the GASP IV simulation language.

3.1 Generator Modeling

The model used for this simulation is a three state model in which a generator may be fully available, partially available, or fully out of service. Transition is possible from any state to any other state and transition rates are furnished as data input. Presently, residence times are assumed to be exponentially distributed for all states.

When a fully-available generator is placed on line two transition times are randomly generated: one for full outage and one for partial outage. The lesser of these times determines which event will in fact occur. If the generator is idled for economic reasons prior to the occurrence of the outage, the outage event is destroyed and when the generator is again placed on line a new outage is drawn from the same distributions as the first.

When a partial outage event occurs the capacity available after derating must be determined. This derated capacity is drawn from an appropriate probability distribution. The partial outage event is also referred to as a derating event. The full outage event is often referred to as a failure event.

Once a failure or derating has occured a transition to one of the other possible states must be generated. This next transition is created by generating random transition times into the two remaining states and selecting the smaller time.

All transition rates for generators in this model have been assumed to be independent of the condition of the system. However, in actual practice the repair times of full and partial outages probably vary with the urgency with which the generator is needed. That is, when high loads and low margins are anticipated repair may be expedited. The existing model could be easily modified to reflect this situation but data to support such a model do not appear to be presently available.

Outage Postponability. Both full and partial outages may be postponable. The model assumes random postponability times for both full and partial outages according to specified probability distributions.

Start-up Failures. Start-up failures are treated in the model by generating a random number from the uniform 0-1 distribution prior to placing the generator on line. If this number is less than the probability of start-up failure furnished as data input for that generator, the generator is failed and not placed on line. It has been assumed that start-up failures are detectable only at the end of the start-up cycle.

Planned Outages. Planned outages are handled by the model in the form of an outage schedule furnished as data input. Up to two planned outage periods per year are permitted for each generator. These outage periods are deterministic and cannot be altered by the program. The model is pessimistic in this regard since a planned outage may actually be rescheduled or "slipped" to some extent if necessary to avoid a capacity shortage. Generator states and transitions are summarized in Figure 1.

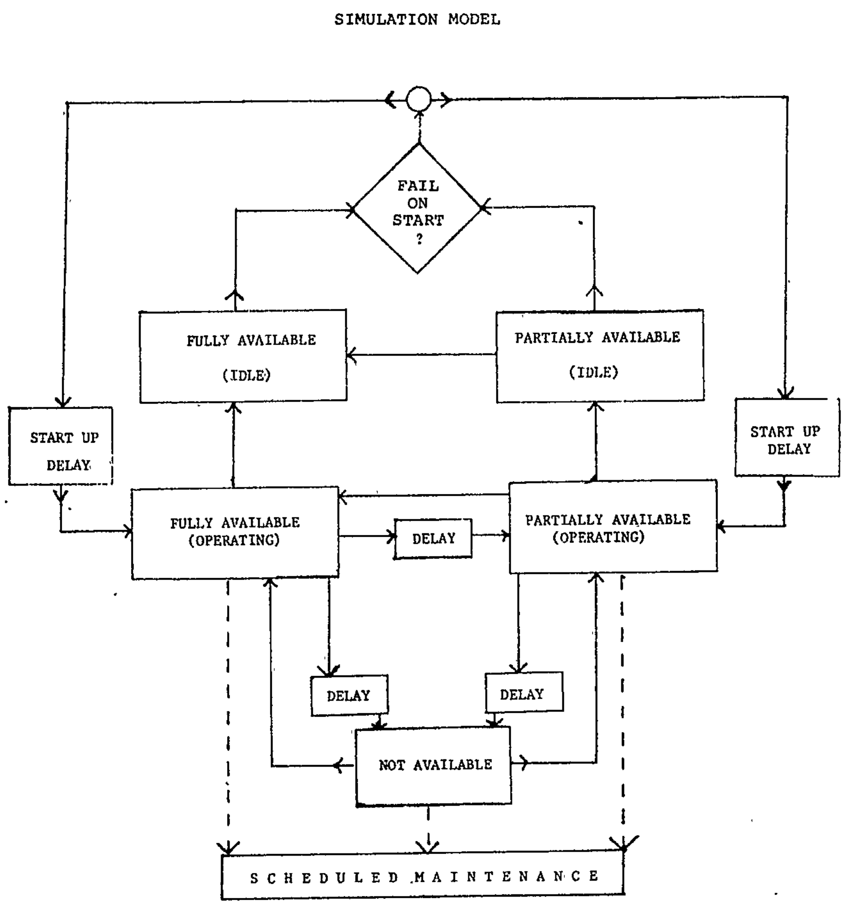


Figure 1: Generating Unit States and Transitions

3.2 System Operating Policies

Reserve Requirements. The simulation program permits any desired operating reserve policy to be specified and enforced through a subroutine called POLICY. Since operating reserve policies vary widely between systems, it is not possible to generalize this subroutine. Therefore, subroutine POLICY must be rewritten to reflect the specific operating policy of the system which is to be studied.

Unit Commitment. The order of generating unit commitment is controlled by a commitment priority list which is subdivided into three categories: base-loaded units, economic-cycling units, and quick-starting units. Base-loaded units are operated continuously unless on outage. The economic-cycling and quick-starting units are committed and de-committed in priority order according to the requirements of the operating reserve policy which is being enforced. The quick-starting units may be committed out of order with respect to the economic-cycling units if additional capacity is required in response to sudden outages.

Pumped Storage Management and Modeling. Pumped storage hydroelectric generators are treated in an approximate manner in the present model. A pumping load cycle in a "typical" period is furnished as data input. Five seasonal "typical" periods were used. This load is added to system demand to obtain system load for each hour. If the operating margin of the system becomes negative, pumping load is reduced.

Modeling of pumped storage units is highly simplified and may create certain unrealistic situations. It is conceivable that due to unit failure pumping load might actually be less than that presumed. It is also conceivable in the model that pumping load could exist while the units are operating as generators. Neither of these anomalies is thought to represent a significant problem in the present study since the amount of pumped storage hydro is not large. However, a more sophisticated pumped storage model would clearly be required for systems with significant pumped storage or where detailed attention is to be focused on the effects of such units. No fundamental difficulties exist in development of a more detailed model.

Postponable Outage Management. Postponable outages have been subdivided in the model into short and long. Short is defined as all outages postponable less than 8 hours. Outages with short postponability are taken immediately, if sufficient reserve exists, or as soon as replacements can be brought on line. In some instances the postponability may be too short for full replacement to be possible due to start-up delay. In this case the outage occurs at the end of the given delay period.

The model employs the following scheme to manage outages having long postponability. Units having outages postponable for long periods are in all instances replaced without startup delay at the time the outage is taken. (This simulates the operater foreknowledge of the time of shutdown of the defective unit and his ability to bring replacement capacity on line at that time.) The model first determines if the repair can be completed over-night or over-weekend. If this condition is met and the postponability time is sufficient, the unit is placed in a special file to be scheduled for off-peak repair. All other outages are listed in another special file.

The model maintains a trouble indicator which is set at 0 (no trouble) if during the next seven days no peak load exceeds present available capacity minus 1000 MW. If peak load exceeds that amount, the indicator will be positive and contains the number of days into the future that this "trouble" is expected. Outages with long postponability which cannot be repaired off-peak are taken in about 8 hours if no trouble is indicated. If trouble is indicated outages are taken in the same manner if either the repair can be completed before the anticipated trouble or the postponability time is short enough that failure would occur before the trouble. However the maximum delay is taken if the unit cannot be repaired before the trouble and the postponability period extends beyond the trouble period.

This outage management logic is used only for outages greater than 30 MW if no trouble is indicated. When trouble is indicated, outages of 15 MW and larger are managed and when the peak-load on a given day is within 1000 MW of available capacity, all outages are managed.

3.3 System Load Modeling

System hourly load is furnished to the model as input data. In the course of simulation system load is updated at the beginning of the hour and is assumed constant for that hour. Presently, the system operator is presumed to have a perfect forecast of loads within the lead time required for starting of economic-cycling units. This presumption is simulated by the starting of units without start-up delay in response to load increases. Note, however, that units started without delay are still subject to start-up failures.

4. STUDIES OF EPRI SYNTHETIC SYSTEM A

The objective of this section is to present a case study of the sensitivity of generating system reliability indices to various operating considerations and constraints. This case study uses a synthetic system recommended by the Electric Power Research Institute (EPRI) and the simulation model described in the preceding section.

4.1 Description of the Study System

The system utilized in the study is drawn from the "synthetic system A (reduced version)" as described in EPRI Report EM-285, "Synthetic Electric Utility Systems for Evaluating Advanced Technologies." The system is composed of 52 units of 12 distinct size/type classifications with a total of 10,675 MW of capacity. System peak load is 8,792 MW and the annual load factor is 59 percent.

Table 1 gives generating unit characteristics. All characteristics in this table except start-up times come from the EPRI report. Starting failure probability was assumed to be 0.05 for all generators. Minimum economic shutdown times of 5 hours for steam units and 0 hours for other units were assumed. Planned outages were not considered in the study nor were hydro unit water limitations or the pumped-storage hydro unit's pumping cycle considered. Generating unit state residence times were assumed exponentially distributed.

Table 1

SAMPLE SYSTEM GENERATOR PARAMETERS

Commitment Priority	No. Units	Unit Type	Unit Cap. (MW)	Total Outages		Partial Outages			Start-up Time(Hr)
				Outage Rate(Hr^{-1})	Repair Rate(Hr^{-1})	Outage Rate(Hr^{-1})	Repair Rate(Hr^{-1})	Per Unit Derating	
1	2	Hydro	50	5.00×10^{-5}	9.71×10^{-4}	-	-	-	0
2	1	Hydro	25	5.00×10^{-5}	9.71×10^{-4}	-	-	-	0
3	1	Nuclear	1200	1.39×10^{-3}	1.13×10^{-2}	1.59×10^{-3}	8.33×10^{-3}	0.23	12
4	1	Nuclear	1000	1.39×10^{-3}	1.13×10^{-2}	1.59×10^{-3}	8.33×10^{-3}	0.23	12
5	4	Coal	600	2.94×10^{-3}	1.54×10^{-2}	1.58×10^{-3}	4.73×10^{-3}	0.21	8
6	3	Coal	400	1.75×10^{-3}	1.67×10^{-2}	1.38×10^{-3}	8.50×10^{-3}	0.22	8
7	13	Coal	200	1.06×10^{-3}	1.89×10^{-2}	1.27×10^{-3}	1.30×10^{-2}	0.24	7
8	1	Oil	400	1.75×10^{-3}	1.67×10^{-2}	1.38×10^{-3}	8.50×10^{-3}	0.22	8
9	2	Oil	200	1.06×10^{-3}	1.89×10^{-2}	1.27×10^{-3}	1.30×10^{-2}	0.24	7
10	4	Coal	50	4.46×10^{-4}	1.89×10^{-2}	1.14×10^{-3}	4.63×10^{-2}	0.15	5
11	1	P.S. Hydro	200	1.67×10^{-5}	1.54×10^{-3}	-	-	-	0
12	19	C.T.	50	6.58×10^{-3}	2.08×10^{-2}	-	-	-	0

When considered, the maximum postponement time of a total or partial outage is assumed to be a random variable possessing the cumulative distribution function:

$$F(t) = \begin{cases} 0 & t < 0 \\ .1 & t = 0 \\ 1-.93^{-t/24} & t > 0 \end{cases}$$

It should be pointed out that the unit outage rate given in Table 1 reflects typical forced outage rates only and excludes maintenance outages. Thus it is assumed, in effect, that maintenance outages are postponable to such a degree that they have no effect on system reliability. This is an assumption commonly made in reliability studies using analytical methods, but an assumption which the simulation model, in general, seeks to relax through inclusion of maintenance outages together with proper modeling of their postponability. Nevertheless, in this study, maintenance outages are ignored for all purposes.

The operating policy assumed in the study of the sample system is outlined as follows:

1. A spinning reserve of 1500 MW is desired at all times.

2. When the spinning reserve falls below 1500 MW units are added in priority order to restore the desired reserve. Likewise, when spinning reserve is excessive, units are removed in reverse priority order to maintain the desired reserve.

3. Postponable outages, when postponability is considered, are managed in accordance with the procedure already discussed for the simulation program. That is, efforts are made to schedule postponable outages after reserves are started and at times of low system load.

4. Load is assumed forecastable without error. Thus, the start-up process for units started in response to load increases is assumed to be initiated at a time which will permit these units to be in service at the time they are required.

4.2 Sensitivity Studies

Six cases have been studied for the sample system. The first case contains the classical idealizing assumptions typically used in analytical methods and is the basis for comparison of the other cases which systematically add operating considerations. The cases studied are summarized as follows:

Case 1: Assumes that all units run continuously except when in a state of total outage (classical assumptions).

Case 2: Operate to maintain a spinning reserve of 1500 MW. Assume all unit start-up failure probabilities are zero and all starting times are zero. Outage postponability is not considered.

Case 3: Same as Case 2 except that all unit start-up failure probabilities are 0.05.

Case 4: Same as Case 2 except that unit starting times are as given in Table 1.

Case 5: Same as Case 4 except that all unit start-up failure probabilities are 0.05.

Case 6: Same as Case 5 except that outage postponability is considered.

Certain important reliability indices obtained from the six cases studied are summarized in Table 2. Indices are based on simulations of thirty years of sample system performance.

Table 2

SUMMARY OF RELIABILITY INDICES FOR SENSITIVITY STUDY CASES

Reliability Index	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6
E(No. of neg margin hours per year)*	17.5	9.7	34.8	14.6	49.0	36.0
E(No. of daily peaks not supplied per year)	3.2	2.0	5.8	2.63	8.4	6.2
E(Unserved MWH per year)	7.315×10^3	3.28×10^3	1.55×10^4	5.78×10^3	2.22×10^4	1.59×10^4
E(MW load not served per load loss event)	419	328	444	380	453	442
E(Duration of load loss events, hrs.)	4.7	4.1	5.2	5.0	5.2	5.3

*E(·) denotes the expected value of a quantity.

Some general observations are in order before the results of the studies on the sample system are discussed. Study results are undoubtedly influenced by the characteristics of the particular system studied including generating unit parameters, generation type mix, and installed reserve level. Thus, study results are not presented as typical but rather as indicative of the possible effects of operating considerations on computed reliability indices. Much more extensive sensitivity studies will be required before strong conclusions can be drawn.

Some conclusions from the sensitivity study on the sample system are presented as follows:

1. Case 2 operation differs from Case 1 operation in that units are cycled on and off to maintain a 1500 MW spinning reserve rather than being run continuously. Therefore, since start-up failure probability is zero and starting time is zero in Case 2, it follows that the primary difference in Cases 1 and 2 is reduced generator running time (and exposure to failure) in Case 2. It is expected, therefore, that Case 2 should exhibit somewhat better reliability than Case 1. Clearly the difference in Cases 1 and 2 is related to installed capacity reserve and spinning reserve policy.

2. Case 3 operation is the same as that of Case 2 except that generator start-up failures are considered. The results of Table 2 indicate that start-up failures can have a fairly significant effect on reliability indices.

3. Case 4 is similar to Case 2 except that generator start-up times are modeled. Results indicate that start-up time can have an important effect on reliability indices and should be considered for accurate resutls. The effect of start-up times is probably very much related to system size, generation type mix, and operating reserve policy.

4. Case 5 illustrates that the consideration of both start-up times and failures yields an effect greater than might be expected from the cases considering either alone. This reflects delays in bringing additional units on line should units being started fail at the completion of their start-up times.

5. Case 6 is identical to Case 5 except that outage postponability is modeled in Case 6 whereas outages were assumed to result in immediate loss of capacity in Case 5. Outage postponability, assuming the postponement time distribution studied, is shown to have an important effect in improving system reliability realized. Clearly, the degree of postponability of outages will have an influence on computed indices and should be modeled for accurate results. The indices of Cases 3 and 5 provide bounds on the effect of outage postponability. Case 3 should approximate the effect of very long postponability times while Case 5 reflects no postponement.

5. APPLICATION OF GENESIS TO AN ACTUAL SYSTEM

GENESIS has been applied to an actual operating system consisting of over 500 generating units. System data were furnished by the operating utility and assembled and checked by members of the Electric Power Institute. This system, one of the largest power pools in the country, represents a truly formidable test bed for a simulation approach. This utility employs a tri-level reserve policy consisting of spinning reserve, primary reserve (spinning reserve plus capacity startable within 10 minutes) and operating reserve (spinning reserve plus capacity startable within 30 minutes). The level of each reserve requirement varies by season of year, day of week, time of day, load, and other factors. Two GENESIS subroutines, which are specific to this utility, determine the proper reserve levels for each hour and ensure that these requirements are enforced.

GENESIS has been verified by a three stage procedure, testing the random features of the model, the system analog features of the model, and the results of the model. Random features of the model were verified by checking the operating experience by class of generator, which is furnished as program output. The number of starting failures, number of operating failures, and average repair time were tested. Postponability times and specific transition times were spot checked on an occasional basis. This verification process revealed one serious error in the model. Due to the omission of one line of code, no transition from the failed state to the derated state was generated, although coding existed which should have generated such transitions. This error was detected when average repair times were found to be too large for all generator classes. Once identified, the error was easily corrected.

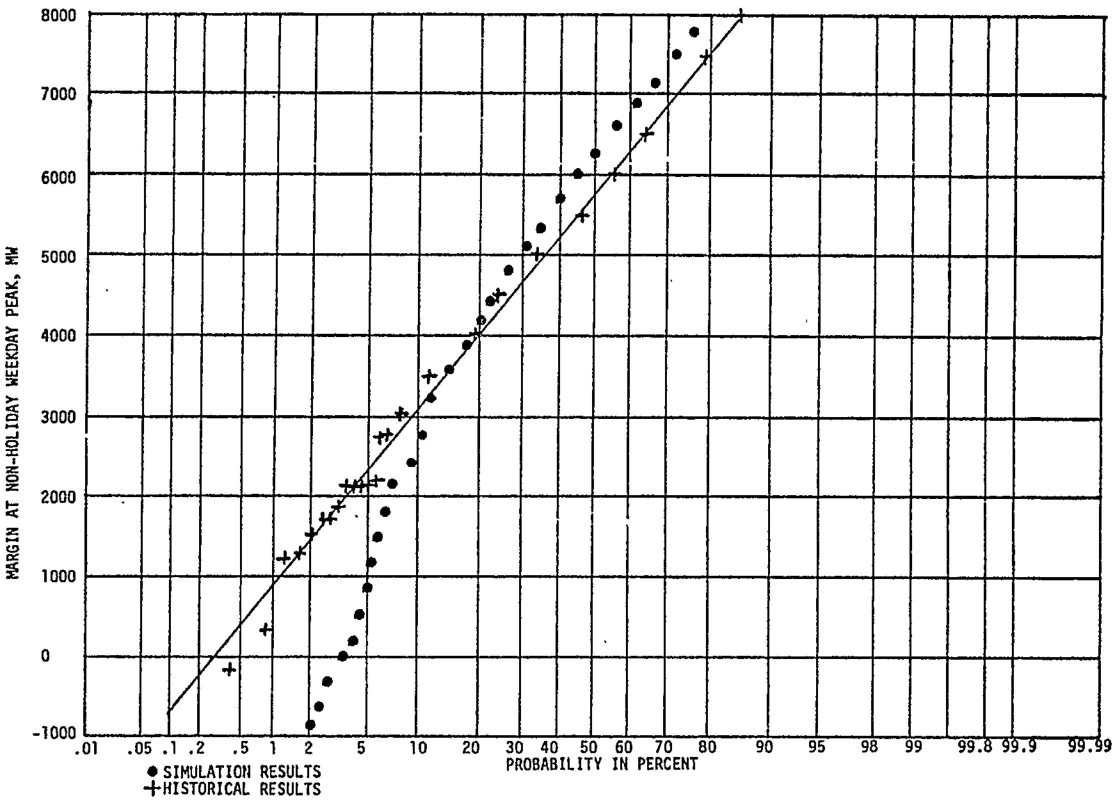
The system analog features of the model were verified by extensive examination of event traces. An event trace causes each subroutine to print a short message as it executes containing any data used to make a decision. GENESIS has been programmed so that a trace of all events occurring between any two times can be obtained by including the times as data input.

Event traces for various periods during the simulated year were carefully examined to verify that units were being cycled properly and that the reserve requirements were enforced. This verification process extended over several months through various versions of the model. Early versions of GENESIS had a tendency to cycle generators too often. No production runs were made with GENESIS until the system analog features were executing satisfactorily.

The most important part of the verification process is in the comparison of simulation results with historical results. This comparison may be separated into two portions, comparisons of system parameters and comparisons of unit operating experience. System parameters measured include margin and capacity on (forced or maintenance) outage at non-holiday weekday peaks. The major parameters tested for generating units were the number of starts and the number of operating hours, which are indications of whether unit cycling is being modeled properly.

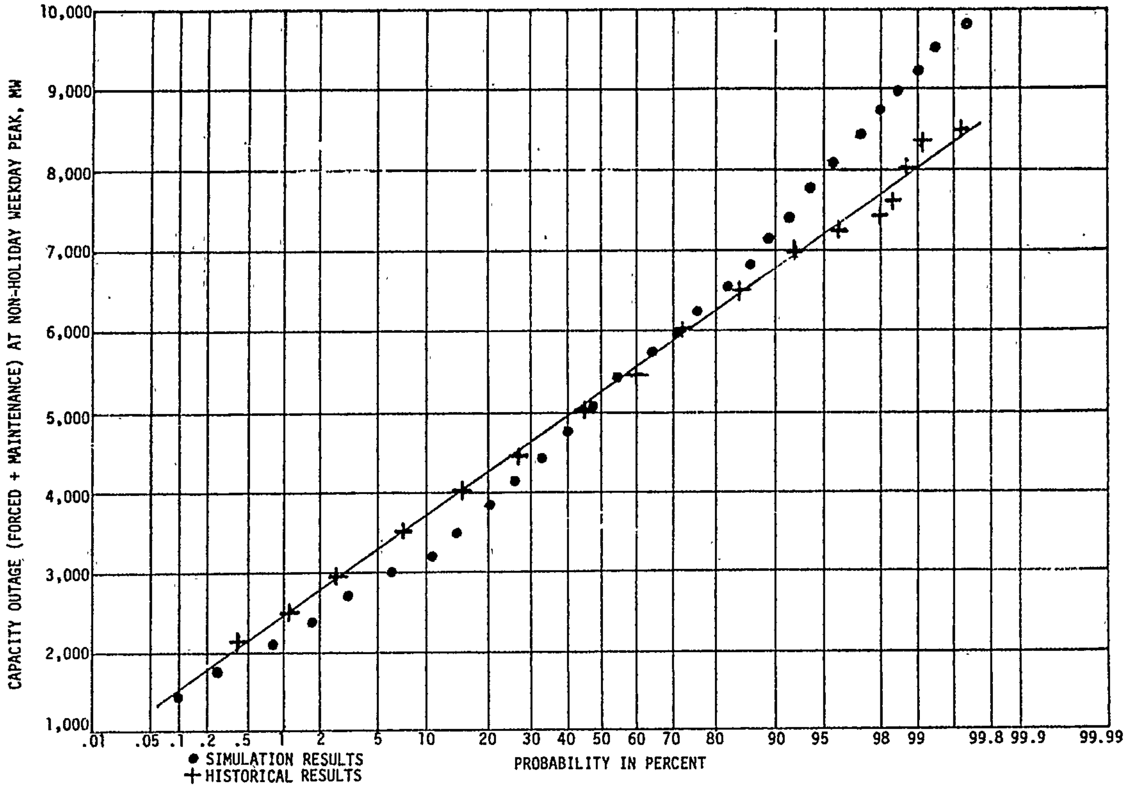
A comparison of the simulated and historical margin (supply-demand) is shown in Figure 2. Note that although GENESIS yields very good results for high margin periods, the results deteriorate for lower margin areas. These results were expected due to deficiencies known to exist but not correctable with data presently available. These problems involve the urgent repair rate phenomenon and the distribution of outage postponability. GENESIS models repair time distributions as stationary, when in fact repair rates likely reflect the urgency with which the generator is needed. Thus repair times are probably substantially shorter than those used in GENESIS when margins are low and somewhat longer when there is ample margin. The outage postponability distribution used in GENESIS was extrapolated from three points estimated by system operators. When a unit encounters operating trouble, the operator estimated whether the outage is postponable beyond the coming weekend, to the weekend, or less than this. Actual postponability times are not collected. It is believed that current estimates for delay times are probably somewhat conservative. Correction of these two problems should significantly improve the performance of GENESIS at both ends of the distribution of margin at non-holiday weekday peak, but especially for periods of low margin. Both problems require data not presently available but which could possibly be obtained given time.

Figure 2: Margin at Daily Peak, Historical Results & Simulation Results



A comparison of capacity on outage at weekday peak between the model and the actual history is given in Figure 3. Note that capacity on outage for the model crosses the historical results at the median of the distribution. This would indicate that the percentage of outages postponable to the weekend must be nearly correct, since otherwise the model and the actual system would have experienced a different pattern of weekend repair and hence a different median available capacity at weekday peak. The deviation of the model results from historical results at the extremes of this figure is thought to be due to the lack of a state dependent repair process in the model and this deviation may be exacerbated by the use of maximum postponability times in the model which are shorter than that actually experienced. Inspection of Figure 3 tends to reinforce the conclusions drawn from inspection of Figure 2. The only additional information inferrable from this figure is that the fraction of outages postponable to or beyond the next weekend appears to be correct.

Figure 3: Capacity on Outage at Daily Peak, Historical Results and Simulation Results



Operating histories by class of generator are compared in Table 3. Note that in general units are experiencing approximately the correct number of operating hours. There is a large discrepancy in the operating hours for fossil steam plants from 100 MW to 249 MW. Examination of the average number of starts for these units in the historical data, reveals that they were run whenever available, whereas data furnished by the utility indicated that some of these units were to be used as peaking units. This data discrepancy is thought to be responsible for the difference in operating hours. Also note that hydroelectric units experienced too many operating hours in the model. This discrepancy is likely due to the fact that the model does not consider the availability of water to operate hydroelectric units. Finally note the peaking units are generally not receiving a sufficient number of startups. This may be due in part to the lack of load forecast error in the simulation and also in part to the failure of the model to use peaking units rather than cycling steam units to meet peak loads of short duration. Until data can be collected to permit modeling of a state dependent repair rate one cannot tell whether any of these problems will have sufficient impact on the results obtained by GENESIS to justify program revision. It is thought that the impact in all cases is minor.

GENESIS is producing good results given present data limitations and shows promise of producing much better results in the future. Execution times for GENESIS using the enhance GASP IV code are remarkably low, far lower than anticipated by most experts in the field. In fact, it would seem apparent that the decision on the part of system planners to overlook simulation due to its high computation costs bears reexamination. For this study simulation runs of 5 years on a very large system require less than 6 minutes on the Amdahl 470/V6 which translates to a cost of under $50. Considering the consequences of possible decisions and the need for energy conservation these seem like incidental costs.

One observation on the cost of simuation modeling seems worthy of further note. At the inception of this study it was believed that studying a small power system would be much less expensive than studying a large system. The research performedherein indicates the system size has little effect on the cost of a study. Large systems require more time to execute each year of simulation, but the number of simulated years required to obtain convergence is smaller due to less variability between simulated years. To date GENESIS has been used to model two systems, one having 50 units, the other 500 units. Very little difference in production costs was experienced, since more observations of the 50 unit system had to be taken to obtain the same degree of convergence in the results.

Table 3: Operating Experience by Class of Generator

	Running Time	No. of Starts	No. of Outages	Full Outage Time	Average Outage Time
Fossil (0-99MW)	5774* (5922)+	106 (72)	9 (10)	702 (805)	80 (80.5)
Fossil (100-249MW)	6510 (7347)	93 (21)	13 (14)	616 (678)	48 (48.4)
Fossil (250-499MW)	6351 (6195)	43 (31)	22 (20)	1315 (1141)	60 (57.5)
Fossil (500MW)	6481 (6560)	21 (21)	21 (20)	1461 (1427)	71 (71.4)
Misc.	4660 (5993)	216 (119)	4 (6)	189 (285)	50 (47.5)
Hydro	7486 (5561)	98 (260)	9 (8)	180 (156)	19 (19.5)
P.S. Hydro	1970 (2276)	199 (438)	26 (31)	626 (759)	24 (24.5)
Gas Turbine	1042 (1236)	131 (180)	21 (29)	758 (1032)	35 (35.6)
Nuclear	6300 (6414)	11 (9)	9 (9)	1729 (1632)	188 (181)
Single Jet	1104 (527)	96 (120)	22 (17)	1076 (832)	50 (48.9)
Multi Jet (30-69)	631 (536)	87 (164)	16 (22)	337 (450)	21 (20.5)
Multi Jet (70-250)	851 (1384)	97 (312)	12 (32)	285 (808)	25 (25.3)
Diesel	225 (272)	43 (70)	2 (2)	346 (346)	173 (173)

*Simulation Results

+Historical Experiences

6. SUMMARY OF RESULTS

Existing analytical models of electric power utility reliability are capable of measuring the relative reliability of power systems, but cannot predict the absolute reliability of a system. A simulation model would be extremely useful if (1) it could predict the absolute reliability of a system within reasonable limits, and (2) computation costs for operating the model were reasonable. At the time this study was begun "the position often taken by experts on this continent is that simulation requires too much computing time in most applications" [15]. The GENESIS model has advanced the state of the art of power systems simulation to the point that one of the largest generator pools in the United States was modeled with an execution time of just over one minute per simulated year on an Amdahl 470/V6 computer. This execution time is considered remarkably small for a system of the size and complexity treated in this study. This low execution time is attributable not only to a careful approach to the modeling of the system itself, but also in larger degree to the sweeping improvements to the GASP IV program, which are discussed in [5].

At present GENESIS produces accurate predictions of reliability only over a portion of the distribution of margin at daily peak. The authors contend that GENESIS could produce better results if data were available for improved modeling of the urgent repair rate phenomenon and of postponable outage management, and preliminary results of further study have supported this contention. The results obtained in the present study indicate that these two changes alone could result in a model capable of making accurate absolute reliability predictions.

This research has demonstrated that Monte Carlo simulation is a viable technique for the study of the reliability of large systems of electric power generators. The cost of executing GENESIS is quite reasonable, even for large scale systems. The results of the present study indicate that future efforts to refine Monte Carlo simulation models of electric power generators are justified.

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