Application of Monte Carlo Simulation to Multi-Area Reliability Evaluations

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The reliability of the electric power system is becoming an increasingly important issue for utility planners because of the recent increase in load demand growth and the limited amount of new generation that is currently planned.

The primary function of an electric utility is to provide energy to satisfy the system load demand as economically as possible while maintaining a reasonable level of reliability. If a utility has no interconnections to outside systems and operates in a totally isolated environment, the only options available for maintaining system reliability are to upgrade existing equipment or to add new generating units and transmission facilities. If a utility has ties to neighboring systems, which is usually the case, it will rely on these systems to provide some of the reserves needed for reliability. This sharing of reserves takes advantage of the load and outage diversities that may exist between neighboring systems, and allows each utility to maintain the desired level of reliability with lower installed reserves compared to isolated operation. The result is reduced reserve costs.

In the past, calculating the reliability of a system with many interconnected areas has been difficult due to the lack of accurate and efficient computer models. Most of the system reliability models currently used are based on the traditional analytical approach of convolving the generation outages with the loads to determine an expected number of outages per year. While this technique works well for single-area systems, it requires excessive computation time when expanded to several areas. Modeling a multi-area system within a reasonable amount of computer time mandates numerous approximations and assumptions; these can often lead to inaccurate results.

Monte Carlo Simulation for Reliability Evaluation

The Monte Carlo approach to reliability evaluation avoids these problems. It provides a detailed and accurate modeling of the system with computer running times that are significantly less than those of other methods for studying multi-area systems.

In a Monte Carlo simulation, a series of scenarios or snapshots of the system is obtained by hourly random drawings on the status of each generating unit and transmission link and determining the hourly load demand. The desired capacity margins or other measures of performance are calculated for the hour, with the process repeated for the remaining hours in the year. Annual indices are calculated from the year's accumulation of data generated by the simulation process. The year continues to be simulated, with new sets of random events, until obtaining statistical convergence of the desired indices.

There are two types of Monte Carlo simulation approaches:

- Nonsequential
- Sequential.

Rather than progressing through time chronologically or sequentially, a *nonsequential simulation* process considers each hour to be independent of every other hour. Consequently, nonsequential simulation cannot accurately model issues that involve time correlations. Therefore, the modeling of unplanned outage postponements or unit starting failures and the calculation of time-related indices, such as frequency and duration, are impossible with this technique.

A *sequential simulation*, however, steps through time chronologically, recognizing that the status of a piece of equipment is not independent of its status in adjacent hours. Equipment forced outages, for example, are modeled by taking the equipment out of service for contiguous hours, with the length of the outage period determined from the equipment's mean time to repair. The sequential simulation can model any issues of concern that involve time correlations and can be used to calculate indices such as frequency and duration.

The Multi-Area Reliability Simulation (MARS) program is based on a sequential Monte Carlo simulation. The first phase of the program was funded by the Empire State Electric Energy Research Corporation (ESEERCO) to enable New York State utilities to analyze comprehensively the reliability of the interconnected electric power generation system in New York and neighboring areas. The version of the program current-

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ly being tested by the New York Power Pool models 5 pools, 15 areas, and 1,300 generating units, with up to 10 partial outage states modeled for each unit.

Reliability Measures Available from Monte Carlo Simulation

Monte Carlo simulation can be used to calculate the traditional reliability indices, including:

- Daily loss-of-load expectation (LOLE), days per year
- Hourly LOLE, hours per year
- Loss-of-energy expectation (LOEE), MWh per year
- Expected number of days per year that emergency operating procedures would be initiated.

Because a sequential Monte Carlo simulation steps through time chronologically while modeling the random forced outages on the generating units and transmission equipment, time-correlated indices such as the frequency of system outages (outages per year) and average duration of the outages (hours per outage) can also be computed on both a single-area and multi-area basis.

In addition to calculating the expected values for the different reliability indices, a Monte Carlo simulation can provide probability distributions for the various indices (see Figure 1). The probability distributions are developed from the results of repeated system simulations using a different combination of random forced outages each time. The distributions show the year-to-year variation in the reliability indices that a system would actually experience over time, rather than just the single average value. This gives the planner additional information to use in measuring the reliability of the system.

Expected Values Versus Probability Distributions

The *expected value* of a reliability index is the average of the observed values of the index over a sufficiently long period of time. It is very likely that the index for a given year will never exactly equal the expected value; some years it will be greater and other years less depending on the random forced outages that actually occur during the year. The expected value contains no information as to how much the index will vary from year to year. Historically, expected value reliability indices have been widely accepted due to their being the only measures readily available from the analytical models generally used.

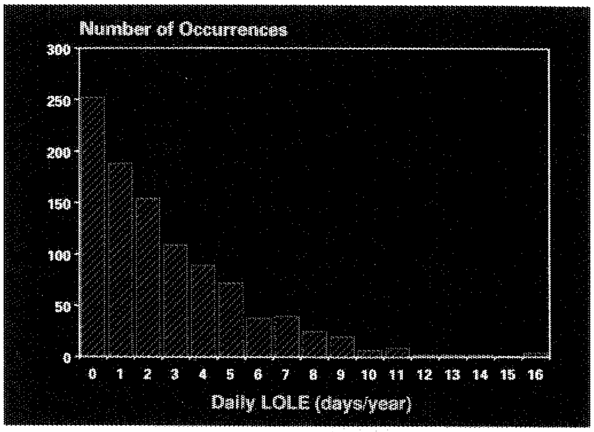

Figure 1. Distribution of daily LOLE (expected value = 2.6 days per year)

The *probability distributions* that are available from a Monte Carlo simulation show the actual annual variations that a system can be expected to experience. If the variation about the expected value is large (as shown by the distribution), it will be difficult for the consumer or the utility to detect small to moderate changes in the expected value. This suggests that a confidence interval on the reliability index may be a more meaningful measure of reliability than the expected value. In practice, alternatives with substantially overlapping confidence intervals would be viewed as yielding levels of reliability that are indistinguishable for all practical purposes.

An example of a probability distribution available from a Monte Carlo simulation is shown in Figure 1. The distribution enables the planner to address the question, "How many days of outage will actually be experienced in a given year?" From the system's expected value of 2.6 days per year, one might surmise that 40 percent of the years will experience 2 days of outage, while 60 percent will experience 3 days of outage. On the other hand, the system might experience 26 days of outage one year out of every 10, and no outages during the other 9 years. Both scenarios give an expected value of 2.6 days per year, but the expected value index does not provide any information as to the actual yearly variation that will be experienced.

When simulating the year 1,000 times, the results show that more that 25 percent of the time the system will not experience any days of outage during that year. However, there will also be years in which the system will experience as many as 16 days of outage in a year.

This type of information is essential for a true understanding of the reliability of a system. A year with 16 days of outage will certainly be remembered much longer by the affected parties and, most likely, have a much severer economic impact than those years having just a couple of occurrences. If a utility can take measures to minimize the occurrence of many outages in a given year, even if the long-term average remains the same, they may be very well worth taking.

Emergency Operating Procedures

The daily LOLE indicates the expected number of days per year when the available capacity at the time of daily peak is less than the load. This does not necessarily imply, however, that a utility will not be able to satisfy the load demand; there are steps a utility can enact, known as emergency operating procedures (EOPs), as the reserve conditions on the system approach critical levels.

Emergency operating procedures consist of load control and generation supplements that can be implemented before the load has to be actually disconnected. Load control measures might include disconnecting interruptible loads, voltage reductions, and public appeals to reduce demand. Generation supplements might include operating units at emergency ratings, initiating emergency purchases, and reducing operating reserves.

The use of emergency operating procedures in reliability evaluations permits a system's reliability to be stated in physical terms that relate to the way in which the system would actually be operated. Information contained in the distributions available from the Monte Carlo simulation also can be used to evaluate the emergency operating procedures that can be enacted a limited number of times in a year. An example of this might be an interruptible load for which the contract specifies a limit on the number of allowable interruptions.

For the sample system, what would be the impact on the LOLE if an emergency operating procedure were available that could cover any generating capacity deficiency, but could only be instituted twice during the year? The answer can be found in the distribution of daily LOLE shown in Figure 1.

Using expected values, the emergency operating procedure would be expected to reduce the LOLE from 2.6 to 0.6 days per year. But there are years in which the LOLE is less than 2 days per year before emergency operating procedures are instituted; in these years, the emergency operating procedure would have an impact of less than 2 days.

The actual effect of the emergency operating procedure on the LOLE can be determined from the information in the probability distribution by calculating a new expected value based only on the simulated years with 3 or more days per year LOLE. This calculation results in an LOLE of 1.3 days per year, after the emergency operating procedure. In terms of its effect on the LOLE, the emergency operating procedure that can be instituted twice a year is only worth 1.3 days per year reduction in LOLE on this system. This impact would be very difficult to evaluate correctly with a traditional analytical model.

Evaluation of Benefits from Generation Reserve Sharing

Generation reserve sharing is one solution many utilities are adopting to maintain system reliability. The sharing of reserves allows each utility to maintain a desired level of reliability with less installed capacity. However, this approach can be very computer-intensive when using traditional methods for calculating the reliability of a system that consists of many interconnected areas.

Table 1. Sample system area capacities and peak loads (Pool 1 is Areas 1 through 11.)

Area	Capacity (MW)	Peak Load(MW)
1	5,300	2,800
2	900	1,300
3	6,100	2,600
4	800	1,200
5	750	1,350
6	1,700	1,900
7	3,500	2,100
8	1,900	250
9	100	1,250
10	7,500	8,500
11	3,300	3,700
12	22,00	19,00
13	24,00	21,00
14	21,00	18,00

The following example demonstrates the application of Monte Carlo simulation in evaluating the reliability benefits of sharing reserves in a multi-area environment. The data for the sample system is based on actual utility data but has been modified for this example and is not intended to reflect the reliability of any actual utility systems. The sample system comprises 15 areas and 5 pools. The first pool consists of 11 areas (Area 1 through Area 11), and the remaining pools have one area each (Area 12 through Area 15). The entire system has approximately 1,100 generating units.

The installed capacities and peak loads for the areas are listed in Table 1. Within Pool 1, the locations of the generation and load are such that some areas have

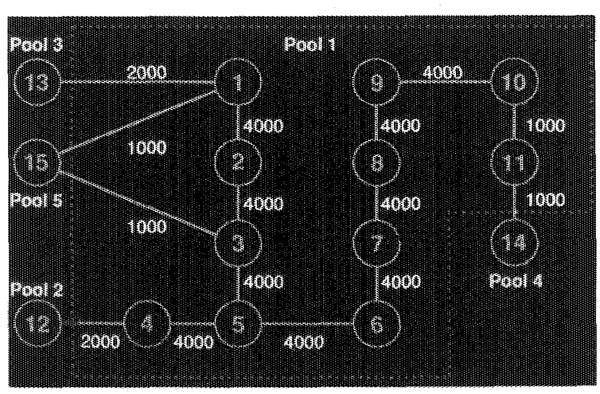

Figure 2. Sample system configuration

significantly less capacity than load and must import much of their generation from neighboring areas.

The area configuration of the sample system is shown in Figure 2, together with the transfer limits (in MW) of the interfaces between the areas. If an area had excess resources available, they were allocated first to the areas in Pool 1 (Area 1 through Area 11), followed by the remaining pools.

The MARS program evaluated the reliability of the sample system. The reliability benefits resulting from Pool 1's interconnections with the surrounding pools were determined by first studying Pool 1 as an isolated pool, without ties to the other four pools. The reliability of Pool 1 was then evaluated as part of the 5-pool, 15-area system.

Table 2 shows the daily LOLE for the 11 areas of Pool 1. Two measures are shown for each area. The first displays the reliability of the areas assuming no interconnections with the other areas in the pool. The second shows the reliability of the areas after receiving assistance from areas with surplus capacity. The isolated values show the wide diversity in reliability that would be expected from the area capacities and loads shown in Table 1. When the interconnections within the pool are considered, all of the areas except for two are at about the same level of reliability. Areas 10 and 11 remain the most unreliable because of the transfer limitations into those areas.

The reliability of the 5 pools was then evaluated using the full 15-area model. The results in Table 3 show the reliability of the individual pools before and after the interconnections that exist between them are taken into account. Because of the available assistance from the neighboring pools, the reliability of Pool 1 improves from almost 29 days per year to less than 8 days per year. Pools 3 and 5 also experienced a similar improvement in reliability on an interconnected basis.

Table 2. Area and pool daily LOLE, days per year (Pool 1 with no external interconnections.)

Area	Capacity (MW)	Peak Load (MW)
Area 1	0.0	0.0
Area 2	336.9	0.0
Area 3	1.2	0.0
Area 4	352.2	0.0
Area 5	365.0	0.0
Area 6	133.4	0.1
Area 7	13.8	0.0
Area 8	54.0	0.1
Area 9	365.0	0.8
Area 10	202.5	18.8
Area 11	143.4	26.0
Pool 1		28.9

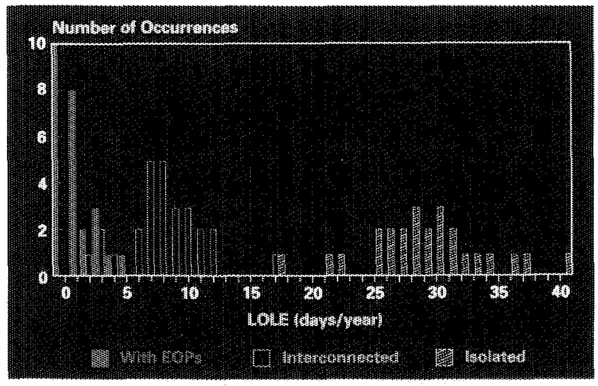

Figure 3. Pool benefits of generation reserve sharing

MARS also calculated the daily LOLE at different user-specified margin states to simulate the reliability benefits of emergency operating procedures. Assuming that 2,000 MW of emergency relief is available in each pool, the reliability of Pool 1 improves from 7.8 to 1.2 days per year.

Figure 3 summarizes the reliability of Pool 1 in terms of the probability distributions. Assistance to Pool 1 from surrounding pools improves its reliability from almost 29 to less than 8 days per year. In fact, at an LOLE of 8 days per year, Pool 1 might be expected to actually disconnect load about 1 day per year after enacting emergency operating procedures. These results clearly demonstrate the reliability benefits of reserve sharing between the pools.

A major problem with many existing multi-area reliability models is the excessive computation time required when more than a few areas (typically four or five) are studied. Computer running times can be a function of many variables, such as the total number of generating units, the number of areas, the number of units in each area, the number of interconnections between areas, the strength of these interconnections and the reliability of the areas and the system.

For systems composed of a small number of areas (four or less), the analytical technique may have shorter computer running times. However, as the number of areas increases, the running time of the analytical approach increases exponentially, resulting in very long running times for systems with five or more areas.

Table 3. Daily LOLE (days per year) by pool

Pool	Isolated	Interconnected
1	28.9	7.8
2	0.1	0.0
3	17.6	2.2
4	0.5	0.0
5	25.4	8.1

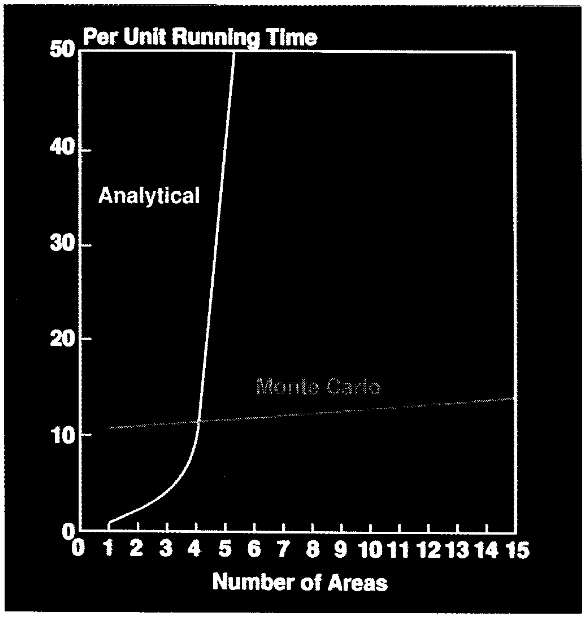

Figure 4. Comparative running times

Figure 4 gives a good indication of the computer time as a function of the interconnected system size by showing the relative computer time versus the number of areas studied for the two different modeling techniques.

With Monte Carlo simulation, the computer time for a single replication is approximately proportional to the total number of generating units, and only slightly a function of the number of areas and interconnections. However, the number of replications required for statistical convergence is affected by the reliability of the system; in general, the more reliable the system, the greater the amount of simulated history that is required for stable statistical results. This is offset by the fact that the need for accuracy is most important for unreliable systems. Generally, it makes little difference if the system expects an outage every 100 years or one every 200 years. However, it is important to know if there will be 10 outages per year or 20 outages per year.

The nature of the system being studied also influences the rate of convergence. Large systems that are not dominated by the status of a few large generators tend to converge after fewer replications than smaller systems that are similarly dominated. This is true because the reliability performance of a large, finely-divided system has little variation from year to year, compared to a system with relatively few generating units. As a result, the computer time required for convergence of the reliability measures is roughly the same for small and large systems. Consequently, Monte Carlo simulation tends to be more computer-time effective than the analytical methods for large systems.

The large system used in the example was composed of 15 areas and 1,100 generating units. Forced outages were modeled with up to four capacity states for each unit. In addition to calculating daily LOLE, the program also calculated hourly LOLE, unserved energy (LOEE) and frequency and duration. The impact of emergency operating procedures was calculated at 10 different margin states. The Pool 1 LOLE converged to a standard error of 8 percent in 55 CPU minutes on a VAX mini-computer. Operation on an IBM mainframe would be about five times faster.

Summary

Monte Carlo simulation is an effective method for calculating the reliability of systems that consist of five or more interconnected areas. In addition to being able to study systems that previously could not be represented in detail because of the excessive computer running time of existing models, the Monte Carlo simulation provides additional information on the reliability measures in the form of the probability distributions. Results obtained from the sample system indicate the importance of including the benefits derived from the utility's interconnections with neighboring systems in the reliability evaluation.

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Biographies

Leonard L. Garver, a GE veteran of almost 30 years, is a senior application engineer in the Power Systems Engineering Department, where he conducts research efforts to integrate generation and transmission planning. He is a key contributor to GE's Multi-Area Production Simulation Program and is recognized as the developer of the *horizon-year* method of transmission network planning. An IEEE Fellow, he received his BSEE, MS, and PhD from Northwestern University.

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Gary A. Jordan, a senior application engineer with the Power Systems Engineering Department, has been involved in the development of simulation tools for utility system planning and is one of the primary authors of GE's Multi-Area Production Simulation Program. He has also taught seminars on system planning. He received his BS and ME in Electric Power Engineering from Rensselaer Polytechnic Institute.