ELECTRIC UTILITY SYSTEM RELIABILITY ANALYSIS: DETERMINING THE NEED FOR GENERATING CAPACITY

Bruce Biewald and Stephen Bernow
Energy Systems Research Group
89 Broad Street
Boston, Massachusetts 02110
(617) 426-5844

Introduction

Recently, some electric utility systems have increased their reserve margin requirements, with direct and significant implications for capacity planning and electricity rates. The additional capacity required to satisfy the increased reserve targets can be costly, as can the impacts of capacity shortages. Therefore, reserve planning should be approached with state-of-the-art analyses and, just as importantly, a full knowledge of the capabilities and weaknesses of the models and techniques used in these analyses.

In planning future capacity requirements, electric utilities commonly use the reserve margin as a measure of capacity needs. Reserve margin standards have also been applied by regulators in making utility ratebase disallowances for excess capacity. However, the reserve margin is not an end in itself -- but is only a rough indicator of the reliability of an electric utility system. Moreover, a single change to the system, such as the addition of a nuclear generating unit, can change the reserve margin requirement of a utility by several percentage points. Thus, it is important to assess reliability more directly, by calculating "loss of load probabilities" (and other measures of the ability to serve load) using computerized models of system reliability.

Probabilistic "reliability models," while essential to a good capacity planning process, require simplifying assumptions that should be made judiciously. We have found that appropriate use of plant performance data, and proper modelling of partial generating unit outages, system emergency operating procedures, and interconnection capability are essential to an accurate assessment of system reliability.

Electric System Reserve Margins

An electric utility system's reserve margin is usually defined as the percentage by which the system's firm resources exceed peak hour firm customer demand. Typically the full seasonal capacity rating of all generating units is included, even for units with scheduled or unscheduled outages at the time of peak demand. The reason for this is that scheduled outages can generally be planned for off-peak seasons as necessary, while unscheduled outages are the principal events for which reserves are provided in the first place.

Firm purchases from other utility companies are also generally included as capacity resources in establishing a reserve margin. The availability of non-firm purchases for short-term emergency or economy power support, while not traditionally counted as a part of reserves, also enhance system reliability and, thereby, will reduce the reserves necessary to achieve a given level of reliability. Thus the reserve margin and transmission interconnections enable a utility to continue to satisfy demand when some of its generating units suffer outages. Moreover, an electric utility has a variety of additional options and procedures available to it to enable it to maintain service to its customers under adverse circumstances.

Maintaining a particular reserve margin is not an end in itself. The objective is a reasonable level of system reliability and the reserve margin, if developed properly, will correlate with an acceptable reliability level.

Capacity Margins

Recently, a number of utilities have begun using <u>capacity margin</u> to express the level of system reserve capacity, replacing the more conventional <u>reserve margin</u> measure. There is no fundamental difference between the two. Reserve margin is defined as follows:

$$\text{Reserve Margin} = \frac{(\text{Firm Capacity} - \text{Firm Load})}{\text{Firm Load}} \times 100$$

And capacity margin, also a simple function of system load and capacity, is defined as follows:

$$\text{Capacity Margin} = \frac{(\text{Firm Capacity} - \text{Firm Load})}{\text{Firm Capacity}} \times 100$$

The two measures are related thus:

$$\text{Capacity Margin} = \frac{\text{Reserve Margin}}{1 + \text{Reserve Margin}}$$

$$\text{Reserve Margin} = \frac{\text{Capacity Margin}}{1 - \text{Capacity Margin}}$$

Thus, a reserve margin of 20 percent is equivalent to a capacity margin of 16.7 percent. While either measure will suffice, the shift from reserve margin to capacity margin can cause some confusion and misunderstanding, especially under conditions of excess capacity. For example, a reserve margin of 40 percent, when reported as a capacity margin, translates to only 28 percent, and consequently may appear less problematical.

Measures of Reliability

Generating system reliability is often quantified in terms of the probability that demand is expected to exceed available firm resources. The loss of load probability, or LOLP, is commonly expressed as the amount of time (for example, days) that demand will exceed resources during a ten-year period on an average or probabilistic basis, given the particular load, resource and interconnection characteristics of the utility system. A more precise term for what is usually referred to as LOLP is loss of load expectation (LOLE), the expected value for the number of occasions (e.g., days) on which the system will experience resource deficiency leading to loss of load. Here, however, we will use the common (although imprecise) terminology.

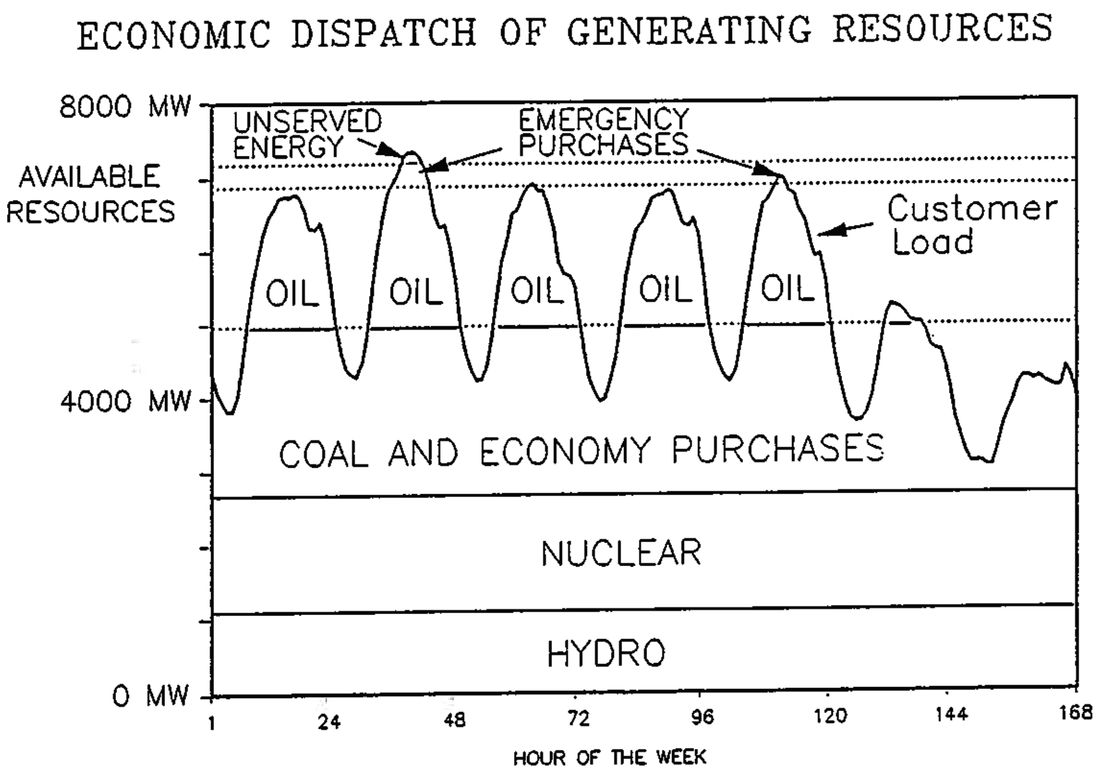
In assessing the LOLP of a system, the generating resources and interconnections must be represented properly. Moreover, the various operating procedures available to the utility to exceed or supplement its generating resources, in order to avoid actual load loss, must be taken into account.

It is important to note that the basic number-of-days-in-ten-years definition of loss of load probability does not explicitly address the magnitude or duration of the expected losses. Losses of load of just a few megawatts for short durations on average have different impacts than do losses of larger magnitude and longer duration. Other measures which describe the duration and magnitude of outages are occasionally used in analyses of electric system reliability.

One measure of system reliability that conveys additional information is "expected energy unserved." This measures the amount of energy demanded but not delivered to customers owing to plant outages. If the LOLP and the expected energy unserved have both been calculated, then the average magnitude of lost load (in MW) can be calculated from these two results.

Figure 1 shows a simplified dispatch of an electric utility system for one week. The heavy line representing customer loads can be seen fluctuating on a daily cycle. One loss of load event is depicted, occurring on the second daily peak of the week.

FIGURE 1



The area above the available capacity (including emergency purchases) and below the customer load curve corresponds with the amount of "expected energy unserved." The horizontal length of the line under the unserved energy represents the duration of the loss of load event. Note that loss of load events can occur at load levels below the peak load, as a result of generating unit outages.

Emergency purchases can serve to decrease the magnitude and duration of a loss of load event, as seen in the second daily peak of the example in Figure 1. They can also help to avoid a loss of load event entirely, as on the fifth daily peak of the example. Note that other emergency operating procedures can likewise reduce the frequency, magnitude, and duration of load loss. These emergency operating procedures can also include voltage reduction, direct load control, customer appeals, and the use of auxiliary generating resources.

Most commonly, reliability criteria are defined in terms of a specified LOLP. Once an LOLP criterion is established, the reserve margin necessary to meet this criterion can be determined by accurately modelling the system. It should be emphasized that the LOLP estimates are theoretical and in practice tend to significantly overestimate actual generation-related outages, as discussed in more detail later.

A loss of load probability of one day in ten years is the criterion most widely used by utilities in the United States. There are, however, significant differences in approaches to modelling interconnections, generator outage rates and various other relevant phenomena in calculating the loss of load probability for a particular system. These differences in modelling approach result in differences in the level of reserves that this criterion implies for a particular system. Data from the nine North American Electric Reliability Council regions indicates that all five of the regional councils that have an LOLP criterion use one day in ten years.

Reserve Margins Used for Reliability Purposes

The usual assumption is that for a large, well interconnected system, a 15-20 percent reserve margin is adequate for reliability. Reserve margins above 20 percent could be required under certain circumstances, especially if the system relies heavily upon large nuclear units which have high outage rates, and also if the system has a very high load factor. However, with sufficient interconnection even heavily nuclear utilities may not need high reserves. One such utility, Commonwealth Edison, plans its system on the basis of a 15 percent reserve margin for reliability purposes.

The principal reason that some utility system reserve margin planning targets have increased to 20 percent and above over the past two decades is the increasing reliance on larger units, particularly nuclear units, which tend to be less reliable than smaller, especially non-nuclear, units. Moreover, it is important to distinguish between the minimum reserves required for reliability purposes, primarily in the 15 to 20 percent range, and planning reserve levels used by some utilities. Often utilities plan for higher levels of reserves than are needed for reliability, in order to achieve overall long-run economics, e.g., by displacing high cost fuels with low cost fuels.

Reliability Criteria Used by the NERC Regional Councils

The North American Electric Reliability Council (NERC) was formed by the electric utility industry "to promote the reliability and adequacy of bulk power supply in the electric utility systems of North America."[1] NERC is divided into nine "regional councils" or regions, which collect data from the utility systems within the region, and perform assessments of the adequacy of the current and projected generating capacity. Most of the regions develop reserve or reliability criteria with which the individual utility systems within the region are expected to follow. In some cases, compliance with the regional criterion is a contractual obligation which specifies penalties for systems with less than the required reserves.

In Table 1, the reliability criteria of the NERC regions are listed. The requirements are expressed in various ways. Each of the five regions that uses an LOLP criterion in assessing the adequacy of power supplies has adopted the standard value of one-day-in-ten-years. These regions are MAAC, MAIN, NPCC, SPP AND WSCC. Five of the regions specify criteria in terms of "reserve margins." These are "ERCOT, MAAC, MAIN, MAPP, and SPP. The reserve margins specified for these regions range from 15 percent to 24 percent.

Diversity of loads allows the reserve margin requirements for individual systems within these regions to be lower than for the region as a whole. The reserve margin requirements specified for individual systems range from 15 percent to 22 percent, with lower reserve margins allowed for hydro-based systems.

The Southeastern Electric Reliability Council (SERC) region is large and diverse. The individual systems in this region are responsible for establishing and providing the levels of generating reserves needed.

The East Central Area Reliability Coordination Agreement (ECAR) uses a criterion expressed in terms of dependence upon supplemental capacity resources (DSCR). With the DSCR methodology, interties with other systems are not represented. No distinction is made between customer demand that would be unserved, and demand that would be served by tie-line support from other systems. With this methodology the criterion is generally (and appropriately) set well above the usual LOLP criteria of 1 day in 10 years, since a 1 day in 10 years LOLP can be satisfied with a much larger level of reliance on outside sources of power. ECAR considers DSCR values in the range of 1 day per year to 10 days per year to be acceptable. The results of ECAR's 1986 appraisal shows that with a generating unit availability rate at the average for the last five years, DSCR requirements is satisfied at a reserve margin of about 19 percent.[2]

Individual utilities within the ECAR region can set their own DSCR criteria much higher than ECAR's, but consistent with ECAR's criterion, owing to the diversity of loads within ECAR and the availability of mutual support amongst its member systems.

Table 1

Reliability Criteria Used by the NERC Regions

Reliability Council	Reserve or Reliability Criterion for Region	Reserve or Reliability Criterion Determined by Region for Individual Systems or Groups of Systems
East Central Area Reliability Agreement (ECAR)	1 to 10 days/year dependence upon supplemental capacity reserves (DSCR)	None
Electric Reliability Council of Texas (ERCOT)	15% reserve margin	15% reserve margin
Mid-Atlantic Area Council (MAAC)	1 day in 10 years LOLP	22% reserve margin
Mid-American Interpool Network (MAIN)	15% to 22% reserve margin to meet 1 day in 10 years	15% to 20% reserve margin
Mid-continent Area Power Pool (MAPP)	21%-24% reserve margin	15% reserve margin (10% for hydro systems)
Northeast Power Coordinating Council (NPCC)	1 day in 10 years LOLP for each subregion	Each subregion has its own method
Southeastern Electric Reliability Council (SERC)	Each system has its own criterion	None
Southwest Power Pool (SPP)	10% reserve margin	18% reserve margin (10% for hydro systems) or 1 day in 10 years LOLP (with 15% floor)
Western Systems Coordinating Council (WSCC)	None	Each system should meet at least one of several criteria, one of which is an LOLP of one day in ten years.

Source: An Overview of Reliability Criteria Among the Regional Councils of the North American Electric Reliability Council (NERC).

Reliability Criteria Used by Selected Utility Systems

Individual utility systems within the NERC regions sometimes develop their own criteria to use for planning purposes. Also, power pools generally set up reserve margin criteria for planning which are sometimes also used for allocating the costs of capacity among the member companies.

The New England Power Pool (NEPOOL), which operates within the NPCC region, currently plans for a reserve margin of about 20 percent, for the period after its two nuclear units have passed their immature stage. This pool uses its reserve margin requirement as a basis for "capacity equalization" payments amongst its members.

Another large pool, the American Electric Power (AEP) system, a member of the ECAR region, uses a DSCR criterion for reliability analysis. DSCR values in the range of 50 to 90 days per year have been considered adequate by AEP for its system. Information presented in AEP's 1985 Generating Capacity Margins Appraisal[3] indicates that even the more stringent end of the DSCR range (50 days) is satisfied at a reserve margin of about 16 percent.

Commonwealth Edison Co. is a well-interconnected utility system in the MAIN region which relies upon nuclear power plants for a large fraction of system capacity (approximately 40 percent currently, with 3 nuclear plants under construction.) The reserve margin used by Commonwealth Edison Co. planners is 15 percent.

The Public Service Company of Colorado, an electric utility in the WSCC region, uses a reserve margin criterion of 11 percent plus a "severe weather component" designed to allow for uncertainty in weather sensitive load. The two components, together, average 14.6 percent for the forecast period.[4]

The New York Power Pool (NYPP) a member of the NPCC region, used an LOLP criterion of one day in ten years, until 1979, at which point the criterion was re-evaluated. The revised NYPP criterion is one disconnection every ten years after accounting for all emergency operating procedures such as voltage reductions and appeals to customers to voluntarily curtail demand.[5] For the NYPP system, this criterion corresponds with a 'conventional' LOLP criterion (i.e., without accounting for emergency operating procedures) of five days in ten years. The expected number of voltage reductions under the new criterion is four per year. Thus, NYPP planners have explicitly recognized the utility's ability to introduce emergency procedures to avoid actual load loss. Assuming capacity transfer capability from other interconnected utility systems, the corresponding reserve margin derived for the New York Power Pool is 22 percent. This implies a reserve margin of only 18 percent for the individual companies within the pool, owing to the diversity of loads.

General Characteristics of Utility Systems Which Affect Reliability and Reserves Requirements

The major characteristics of a utility system which affect the reliability/reserves relationship are:

(1) Load shape

(2) Forced outage rates of generating units

(3) Maintenance outage requirements for generating units

(4) The number and size of generating units

(5) Transmission interties with neighboring utilities

(6) Availability and effectiveness of intervention procedures

A lower system load factor will tend to increase reliability and decrease the reserve margin necessary to meet a given reliability criterion. Lower load factors generally permit more opportunities (during seasonal low load periods) for maintenance, without jeopardizing reliability during those periods, thus allowing greater resources to be available during high load periods.

There are, however, certain economic reasons to prefer high load factors. Thus, it may be that optimum deployment of resources for reliability is sacrificed in order to achieve operating economies. Of course, this would mean that those operating economies would be greater than the additional resource costs (or reliability impacts) incurred. It should be noted that load factor itself is just an aggregate measure of load shape, and that the detailed monthly shapes can have an impact upon system reliability as well.

Most directly, lower forced outage rates for generating units will result in greater system reliability and, consequently, a lower reserve margin to meet a given reliability criterion. Similarly, units which have lower and more flexible maintenance requirements will contribute to greater system reliability and lower reserve margin requirements. Larger (especially nuclear) units typically have higher than average outage rates. They also have less flexibility in maintenance scheduling, start-up and load following. Peaking and hydro resources generally have low forced outage rates and great flexibility to meet rapidly changing loads.

Smaller sized generating units will result in relatively greater reliability and lower reserve margin requirements. For example, consider a system comprised of only two units of 250 MW, each with ten percent forced outage rate. This system will have only a one percent chance of experiencing a 500 MW outage, because for this to occur both units must be forced out of service simultaneously. In contrast, another system with a single 500 MW unit (with the same 10 percent forced outage rate) will have a ten percent chance of experiencing a 500 MW capacity outage. Moreover, as noted above, smaller units tend to have lower forced outage rates.

A utility system which has substantial interconnections with neighboring systems can take advantage of diversity of loads and resources to obtain system support when needed, for those few hours when internal resources are insufficient to meet load. Greater interconnection will result in greater reliability and criterion. Where systems are very well interconnected they should generally be treated as one entity for purposes of reliability analysis.

Finally, utility systems can use a number of options to avoid outages when peak load exceeds the generating resources that are available under normal conditions. These include shedding interruptible loads, re-scheduling maintenance, use of emergency generator ratings, voltage reductions and, ultimately, appeals to customers to reduce usage. The availability and effectiveness of these measures varies from system to system.

Impact of Generating Unit Additions

One of the reasons that it is important to conduct reliability analyses, rather than to simply use a single reserve margin for system planning purposes, is that the relationship between reliability and reserve margin can change. In particular, an abrupt change can occur when a new generating unit is brought on-line.

Recently, some electric utilities have increased their target reserve margins, coinciding with the commercial operation of large new units. In particular, nuclear generating units can have a detrimental impact upon system reliability, increasing reserve margin requirements by several percentage points. There are several characteristics of the new unit that can be important, including its size and its availability.

ESRG has found that for several systems the addition of a new nuclear unit increased the system's reserve margin requirement by four percentage points. That is, in order to maintain the same level of reliability after the nuclear addition began operating, the systems required roughly four percentage points more generating capacity. This additional need occurs for two reasons. First, the outage rate of a large nuclear unit is generally higher than the average for the previously existing system plants. Second, the size of a new nuclear unit is generally much greater than the average size of the existing plants.

Thus, prior to the addition of a major resource, an electric system should evaluate the reliability impacts of the addition. This is particularly important if the characteristics of the resource addition are unlike the previously existing capacity mix.

For reserve margin requirements to change by several percentage points is not unusual, particularly with the addition of a nuclear generating capacity.

Reliability Modelling

Computer models are used to calculate the reliability indices of electric utility systems, including LOLP, DSCR, and unserved energy. The input data requirements and appropriate methodological approach depend upon the question to be answered.

Sometimes these reliability models are used as a check on the adequacy of reliability over some future planning period. The ECAR and AEP reports referred to above are examples of this type of study. System characteristics are projected and reliability indices are calculated. If the calculated indices compare favorably with pre-determined criteria, then the system plan is judged to be adequate.

Another very common application of reliability modelling is in determining the reserve margin required for a particular system to satisfy a particular reliability criterion. Some of the NERC regions perform such studies in arriving at the system reserve margins which will provide LOLP at a level of one day in ten years.

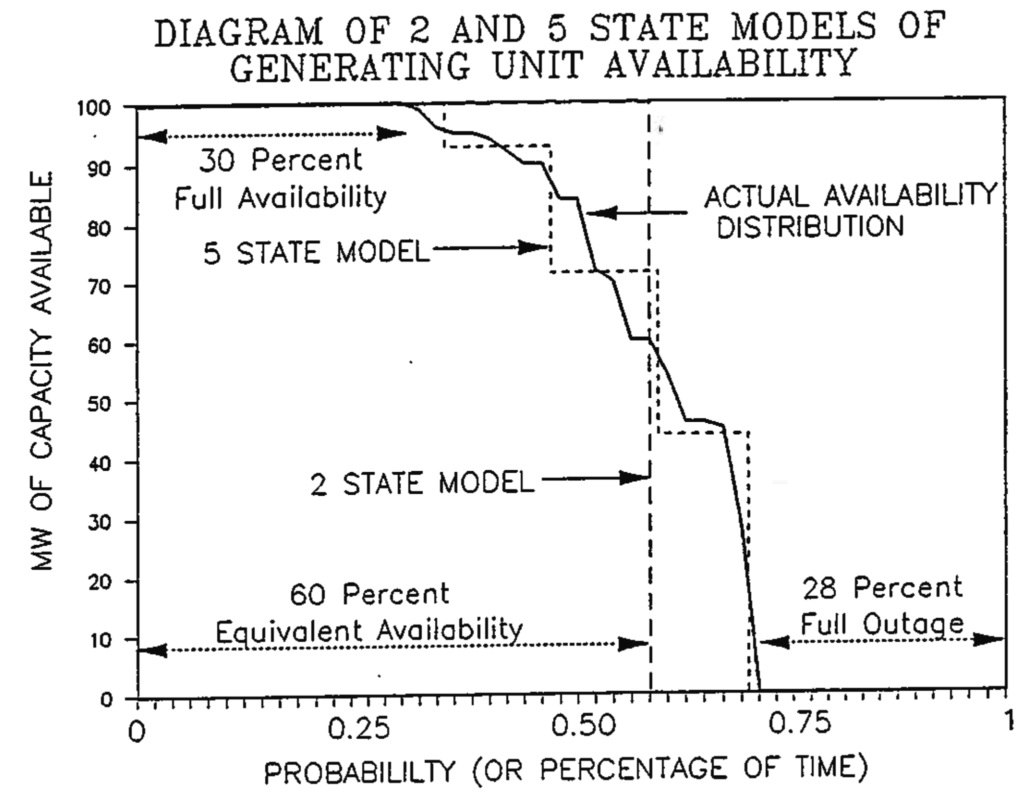
The same computerized dispatch models used for production costing calculations are frequently employed for reliability analysis. Probabilistic techniques are used to "simulate" the random nature of forced generating unit outages. Maintenance outage schedules, as will be discussed below, are usually assumed to be fixed. There are many publications that address reliability modelling generally, for example, books by Billington[6] and Sullivan.[7] Moreover, particular models each have their own documentation.

The essential inputs to computerized reliability models include capacity and outage data for each generating unit, and some representation of customer loads. Intertie support and some of the interconnection procedures are also frequently included in the model.

In modelling generating units for reliability, it is desirable to represent partial capacity outages accurately. Some reliability models are limited to a <u>two-state</u> representation of generating unit availability. That is, at any point in time the unit is assumed to have either <u>all</u> of its capacity in service, or <u>all</u> of its capacity out of service. In reality, however, generating units frequently experience partial capacity outages, in which some -- but not all -- of the generating capacity is unavailable. A <u>multi-state</u> representation of generating unit availability, is preferable to a two-state model, because with more states the actual availability distribution can be accurately represented.

This is illustrated in Figure 2, a capacity availability distribution for a hypothetical 100 MW generating unit. The solid line which declines from 100 MW at 30 percent of the time to 0 MW at 72 percent of the time represents the capacity

FIGURE 2



available from this unit. In this example, the unit is partially available in various capacity states for 42 percent of the time.

With a two-state model, however, the unit must be represented as either fully in or fully out. The capacity distribution associated with this simplified model is a single step, where the partial outages are accounted for as equivalent full outages. In the example, the equivalent availability of 60 percent would be used, with the equivalent full outage at 40 percent, so that the total amount of generation available matches the actual. Thus, the 42 percent of partial outage time is assumed to be divided between equivalent full outages and equivalent full availability (12 percent and 30 percent respectively). The shape of the single step capacity availability curve, however, is only a very crude approximation of the actual capacity availability distribution.

In contrast, the five-state model of generating unit availability, also depicted in Figure 2, is a much closer approximation to the actual availability curve. Like the two-state model, the five-state model involves approximation of the actual capacity availability curve with a step function. However, with the five-state model, more steps are used, with intermediate steps representing partial capacity availability (i.e., partial outage states). The increased number of steps allows the representation of capacity availability to match the actual distribution more closely.

This is no small matter. By using the two-state representation, a system's reliability can be significantly understated. Analysis has shown that the difference between such accurate and crude approximations of partial outages can amount to several percentage points difference in reserve requirements to meet a given reliability criterion. Thus, the terms "equivalent availability" and "equivalent forced outage rates," while accurate for energy calculations, are misleading for reliability calculations.

In reliability modelling, another pitfall related to generating unit forced outage representation is the data itself. Especially for units such as combustion turbines and diesels which are called upon infrequently, the usual outage data can be misleading. The usual equation for generating unit forced outage rate is as follows:[8]

$$\text{Forced Outage Rate} = \frac{\text{Forced Outage Hours}}{\text{Forced Outage Hours} + \text{Service Hours}}$$

Because of the high operating cost of combustion turbines and diesels, these "peaking" units are called upon only occasionally to produce electricity. That is, for these units the number of service hours in usually low and the number of attempted start-ups is relatively high. For this type of unit, a successful start-up could be followed by only a few hours of operation until the unit is intentionally shut down for economic reasons. An unsuccessful start-up might be followed by a much longer period of "forced outage time," until the repair of the unit is completed. Moreover, because these units are only rarely needed to serve load, the repair may be conducted at a very leisurely pace. Thus, for peaking units, the forced outage rate data, collected according to the usual equation does not provide a good measure of the failure rate to be expected in future system operations. While a reasonable forced outage rate to use for a particular peaking unit may be in the neighborhood of 10 percent, the historic data for the unit may show a forced outage rate of 50 percent or higher. In such cases, the higher number will overstate the unavailability of the unit, and should not be used in system reliability analysis.

The discussion of generator outage modelling above has focused upon forced, or randomly occurring generating unit failures. In simulating the reliability of an electric utility system, it is important to model planned maintenance outages properly as well. The major issue in modelling planned unit outages is the allocation of those outages throughout the study period. An annual maintenance schedule can be developed in a sub-optimal manner, such that system reliability will be very poor, even though adequate generating capacity exists. For example, scheduling one or more major resources to be out during the peak load period is likely to be poor practice, and to result in inferior system reliability.

"Optimal" maintenance schedules can be developed by using a reliability model to explore alternate plans. For this type of analysis it is usual to simulate each week of the year separately, calculating reliability indices for each. In practice, levelizing the reliability across the year will result in the best overall annual system reliability. Of course, constraints upon the scheduling of outages can be relevant to such analysis. Such constraints include maintenance crew availability, and refueling requirements for nuclear plants.

Customer loads must be represented in a reliability model. Hourly customer loads are sometimes input, while in other cases only the daily peak loads are used. The use of hourly loads is generally preferable, in that important measures of reliability such as the expected energy unserved can then be calculated. If only the daily peak loads are input to the model, then the number of events (of loss of load or dependence upon others) can be calculated, but the amount of energy involved cannot. The daily peak method, while still in use, dates back to the early development of analytic techniques for reliability analysis. With computers now widely available, the more detailed approach in which system reliability in all hours is considered, must be considered preferable.

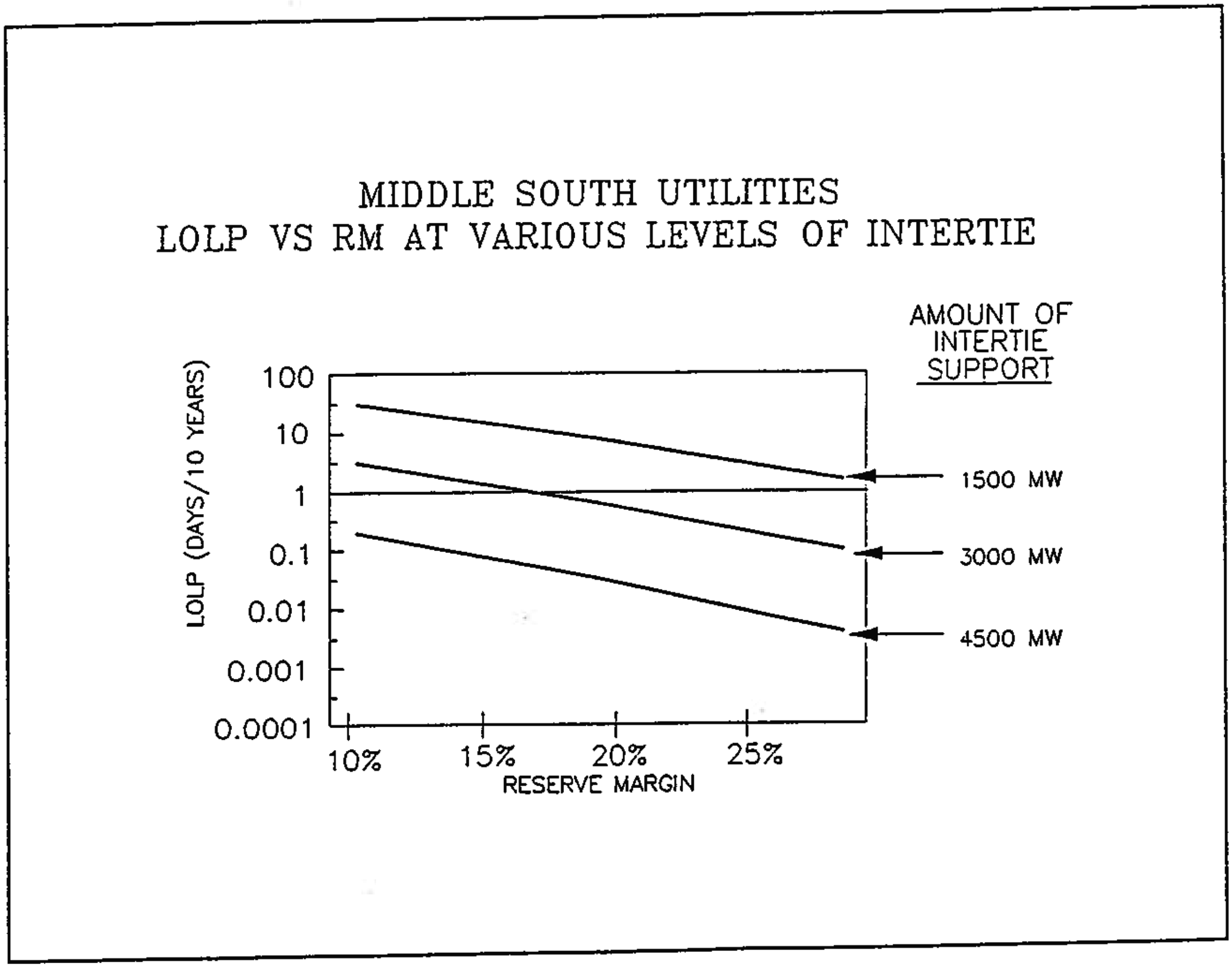
By using both the daily peak and the complete method of load representation, a rich set of reliability measures can be obtained, including the expected number of LOLP or DSCR events, the energy unserved, and, potentially, magnitude and duration information. For example, if analysis using the full hourly load set indicates an expectation of 24 hours of unserved load, and the analysis using daily peak loads indicates that 3 loss of load events are expected, then the average expected duration of each of the three events would be 8 hours (24 divided by 3).

One of the most challenging aspects of reliability modelling is accurate representation of intertie support. Transmission interconnections play a major role in providing reliability, and study results will often be very sensitive to the way in which these interties are represented. In practice, problems can be minimized by selecting the system to be studied appropriately, and by developing inputs for the interties carefully. An appropriate system to study by reliability modelling would be large enough that the role of outside systems in determining reliability is minimized, yet not so large that limits upon the transmission lines within the system will play a crucial role (unless the model being used can accurately represent such limits).

A 1984 survey of utilities by Ebasco Services, Inc., found that: "in most cases where LOLP is used, the assistance available from neighboring utilities is taken directly into consideration: either by representing them as separate resources similar to generation, or by using a two-area model, or by using the results of a reserve requirements study performed on a pool-wide basis."[9] In order to accurately represent intertie capability, transmission modelling (e.g., load flow) exercises and, perhaps, investigations of past experience, are useful.

Figure 3 is a graph of the relationship between LOLP and reserve margin parameterized as a function of intertie from an ESRG analysis of the Middle South Utilities System.[10] The large range of the graph (note that the scale is logarithmic) shows that system reliability is very sensitive to interties. For example, at a reserve margin of 20 percent, the system would experience about 10 LOLP days per ten years if it had 1500 MW of intertie support. In contrast, with 3000 MW of intertie support and all else equal, the LOLP would be less than 1 day per ten years. Finally, with 4500 MW of intertie support, the LOLP would be less than one tenth of a day per ten years.

FIGURE 3



Other Types of Reliability Analysis

There are two other common types of reliability analysis that should be mentioned briefly here. These are transmission system analysis and economic reliability studies, both of which are related to engineering reliability analysis (discussed above), yet different in both technique and purpose.

Transmission system analysis involves assessment of the adequacy of interconnections. Events such as transmission line overloading and cascading tripouts are addressed, rather than the overall adequacy of generating resources. In practice, nearly all actual service outages in the United States are the result of distribution and transmission system failures rather than generating unit unavailability.

The other type of analysis worth noting is the economic reliability study, in which the costs and benefits of providing various levels of reserves are assessed in order to determine an economically optimal margin for planning purposes. The tradeoffs involve many cost components, the most essential of which are the cost of capacity on one hand, and the cost of unserved energy demand on the other.

Such economic studies, if properly performed, provide guidance to system planners by suggesting an appropriate amount for future resource additions. They do not, however, attempt to address the question of what level of resources is required in order to provide reliable service. Nor do such studies address the specific resources that should be included in the plan. A common misuse of this type of study involves finding an "economically optimal" reserve margin for future system planning based upon the cost of peaking capacity, and then using that reserve margin to justify investments in expensive baseload capacity. New baseload capacity additions (i.e., coal and nuclear plants) should be evaluated in terms of their own overall economic impacts. To claim that such plants are justified based upon reserve margin studies which use less-expensive capacity is fallacious.

The Pacific Gas and Electric Company (PG&E) has developed a "value-based" methodology for generation planning.[11] PG&E's approach involves finding the optimal reserve margin, based upon tradeoffs between the cost of peaking capacity and the "cost" of unserved energy. Unexpected swings in load growth and resource availability are accounted for in the analysis. This study represents one of the more ambitious efforts to incorporate economic considerations into electric utility reliability analysis. The PG&E approach is designed to determine appropriate levels of reserves, not the specific type of capacity addition required. Thus, it need not suffer the type of misuse discussed above.

The engineering and economic approaches to system reliability intersect in the area of unserved energy, which is of fundamental importance to both types of analysis. The engineering approach is to limit the LOLP, and thus the amount of unserved energy, to acceptably low values. The economic approach is to ascribe a cost to the unserved energy, thus penalizing scenarios with economically unacceptable levels of reliability.

The appropriate cost to apply to unserved energy is very difficult to determine. Data on the costs incurred as a result of real and hypothetical outages are collected by surveying customers, a technique that is inherently imprecise and error prone. Further, the "costs" incurred due to power outage can vary greatly depending upon location, magnitude, and duration of the outages, which are not calculated in performing a conventional LOLP analysis. There is, therefore, a great deal of uncertainty and therefore further research required in ascribing dollar values to unserved energy demand.

Although the engineering and economic methods differ in technique and intent, in practice the results tend to be similar for systems which do not rely upon high cost fuels for a large portion of their total energy supply. This is because systems which are planned such that a reasonable LOLP criterion is maintained will experience such small amounts of outage that the price ascribed to unserved energy is unimportant. ESRG has found that for a system with a reasonable reserve margin (and therefore an LOLP of about one day in ten years) the amount of unserved energy will generally be less than one hundredth of one percent of total system energy requirements.[12] In general, the amount of unserved energy is directly proportional to the LOLP, at least in the ranges of LOLP with which we are usually concerned.

Reliability: Theory and Practice

A calculated loss of load probability of one-day-in-ten-years does not necessarily mean that some amounts of load will actually not be served for a cumulative total of twenty-four hours over a ten-year period. If interconnections with other companies are not modelled or are understated in the calculation of loss of load probability, then some of the predicted load loss will not occur, as load will be served by power from other companies. Moreover, there are also a number of standard "emergency" operating procedures for avoiding loss of load. Thus loss of load probability calculations, and associated reserve margin determinations, which do not take these factors into account will tend to underestimate reliability and overestimate the reserve margin required to meet a given loss of load probability criterion.

One important method of decreasing the probability of load loss is dynamic scheduling of maintenance. Schedules for maintenance are developed with consideration given to such factors as system production costs, labor crew logistics, and the consequences of maintenance deferral. While schedules for a particular month are often developed several years in advance, particular unit planned outages can be flexibly changed even upon very short notice. For example, if substantial amounts of capacity are forced out of service, then upcoming scheduled maintenance outages are likely to be deferred and any maintenance outages in progress are likely to be speeded up. This is a degree of flexibility not ordinarily (or readily) represented in electric utility reliability modelling. Therefore, such models would tend to underestimate system reliability.

A 1979 Electric Power Research Institute report[13] compared calculated reliability or loss of load probability to historical experience for a particular power system and found that the actual system was more reliable than any of the calculations indicated. The primary explanation given for the difference was the failure of the computer models used to perform the calculations to address "outage postponability, the management of postponable outages, and the acceleration of repair efforts during periods of need."

Other human intervention procedures which typically are not accounted for in loss of load calculations include voltage reduction, or brownouts, voluntary load curtailment and use of emergency generator ratings. While voltage reduction and voluntary curtailment do represent energy demand that is unserved, they have quite different effects than involuntary demand curtailment. Calculated LOLP generally include all the expected loss of load or unserved energy can fall into a regime that can be dealt with by one or more of the above methods before involuntary curtailment or outages need occur. Finally, even when all such emergency generation extension and supplementary measures are exhausted, actual outages can be limited by rotating them for short periods of time through local areas.

As noted earlier, prior to 1979, the New York Power Pool used an LOLP criterion of one day in ten years for planning purposes. Since that time, however, the pool has recognized the failure of the traditional loss of load probability techniques to account for human intervention and so has adopted a reliability criterion which explicitly addresses some of the emergency operating procedures which are implemented prior to actually disconnecting load. The level of reliability chosen for this criterion is "one disconnection every ten years." Disconnection in this case refers to all voluntary and involuntary interruption of service but does not include voltage reductions.

Also, as in nearly all calculations of reliability, the New York Power Pool's techniques understate reliability by not modelling the flexibility of planned outages. The Pool's new criterion corresponds to a loss of load probability of five days in ten years prior to the implementation of emergency operating procedures. Thus, the criterion accepts about four days per year of voltage reduction, and does not take account of the further potential of voluntary curtailment through customers appeals.

Conclusion

This paper has emphasized the need for a number of important considerations in reliability analysis, including:

- Clearly defined measures of reliability (DSCR, LOLP, expected energy unserved, etc.).
- Clearly defined and well founded reliability criteria.
- Accurate representation of system characteristics in reliability simulations.

Certain potentially problematical areas were addressed:

- Accurate modelling of generator outages, including multi-state representation of partial outages and appropriate use of outage data (especially for peaking units).
- Accurate representation of the magnitude and availability of external support -- either by modelling such interconnections and resources, or by defining the system under study broadly enough.
- Accurate representation of emergency operating procedures.

The observations and recommendations made in this paper should help system planners conduct accurate and complete reliability studies, avoiding analytical pitfalls. Proper studies will help to ensure that electric utility systems maintain adequate resources to serve customer load reliably and economically.

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