Probabilistic Assessment of Power Systems

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Invited Paper

Reliability is an important issue in power systems and historically has been assessed using deterministic criteria and indexes. However, these approaches can be, and in many cases have been, replaced by probabilistic methods that are able to respond to the actual stochastic factors that influence the reliability of the system. In the days of global, completely integrated and/or nationalized electricity supply industries, the only significant objective was the reliability seen by actual end users (consumers). Also, the system was structured in a relatively simple way such that generation, transmission, and distribution could be assessed as a series of sequential hierarchical levels. Failures at any level could cause interruptions of supply to the end user (the only specific customer at that time). All planning and operational criteria (both deterministic and probabilistic) were intended to minimize such interruptions within economic limits. The system has been, or is being, restructured quite remarkably in recent times and now many individual parties are involved, often competitively, including generators (both remote large-scale generators, and small-scale distributed or embedded generators), network owners, network operators, energy suppliers, regulators, as well as the end users (consumers). Each of these parties has a need to know the quality and performance of the system sector or subsector for which they (and their shareholders) are responsible. Therefore, there is now a need for a range of reliability measures; the actual measure(s) needed varying between the different system parties. This paper addresses these issues and, in particular, reviews existing approaches and how these may be used and/or adapted to suit the needs and the required indexes of the new competitive industry and the different parties associated with it.

Keywords**—***Distribution, generation, outage costs, power systems, probability, reliability, reliability criteria, reliability worth, transmission.*

I. INTRODUCTION

There have been numerous papers and texts published in the past that explain the reliability assessment of power systems and a number of review articles that summarize the approaches, models, and evaluation techniques. In fact, a continuous stream of relevant papers have been published since the 1930's [1]–[6] and a selection of the most distinctive ones appear in [7]. We have not attempted to identify all these papers individually (in fact, [1]–[6] contain hundreds of relevant and important contributory papers) but have included only those references that directly support the discussions and theory of this paper. Readers wanting a wider set of discussions should refer to these references, which are structured in terms of specific system sectors. A review of all the relevant publications would show that, in many ways, the underlying procedures have not changed to any great extent for some considerable period of time.

Superficially, it could be expected that these existing and conventional approaches would stand the test of time and still suffice and therefore it is reasonable to ask the questions, "What has changed?" and "Why is a new review article needed?". The simple answer is that it is not the models and techniques that have particularly changed or evolved, it is the system organization and the operational environment in which they now have to operate that have changed and continue to change; the primary aspects being unbundling, deregulation (or more specifically reregulation), privatization, restructuring, economic constraints, and similar modifications. Some of these changes are evolutionary whilst others are more revolutionary. Both, however, have meant that existing techniques themselves have had to evolve, not necessarily in terms of modeling developments, but more significantly in the way they have to be applied. It is also worth mentioning at this point that those involved in developing and promoting reliability assessments have continuously stressed the need to consider such assessments in a probabilistic framework and this remains the main thrust of this paper. However, the dominant practice has always been to use a deterministic approach. It is quite likely that deterministic approaches will continue to be used widely in practice. In this case, a bridge between the two approaches (probabilistic and deterministic) may be a valuable way forward. An approach for including deterministic criteria in a probabilistic assessment is discussed later in this paper.

All these new issues are discussed in the following sections, together with their impact on reliability assessments including both technical and economic aspects.

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II. STRUCTURE OF THE ELECTRICITY SUPPLY INDUSTRY

Electricity supply industries (ESI) were originally developed in the form of independent local generators supplying local demands. Although this was initially sufficient, it was soon recognized that an integrated system was needed to create nationally effective systems that were reliable and economic. This led to centrally planned and operated generating plant delivering energy to customers through transmission and distribution networks. This structure may well have continued but for the fact that, more recently, governments have introduced structural measures that attempt to reduce pollution levels, increase the amount of renewable energy generation (this tends to be located in the distribution systems), and open up energy generation and trading to so-called market forces. This has led to an increased number of players in the energy supply industry. These include: generators (these may comprise several independent companies including those trading transnationally); transmission owners and operators [these are not necessarily the same organization, since some systems use independent system operators, (ISO's)]; distribution network owners and operators (usually the same but need not be); energy traders and suppliers (who may only trade and not own any of the actual assets); a regulator (often implemented in order to regulate the monopolistic nature of the networks and to ensure transparency in energy dealings); and the actual end-customers (consumers) themselves.

Most of our current reliability models, techniques, and application tools have been developed on the basis of the centrally planned and operated nature of generation, transmission, and distribution. However, because of this newly defined structure and the increased number of players in the energy trading market, the existing techniques and practices have to be reviewed and updated. This paper addresses these issues with particular mention of reliability economics and embedded generation.

III. BACKGROUND TO RELIABILITY AND RELIABILITY WORTH

As a concept, reliability is an inherent characteristic and a specific measure that describes the ability of any system to perform its intended function. In the case of a power system, the primary technical function is to supply electrical energy to its end-customers (consumers). This has always been an important system issue and power system personnel have always strived to ensure that customers receive adequate and secure supplies within reasonable economic constraints. In the days of global, completely integrated and/or nationalized industries, the only significant measures required were those that were able to assess this overall function. Historically, this has been achieved using deterministic criteria, techniques, and indexes. For instance, since the late 1970's, the U.K. criteria have centered on the application of Engineering Recommendation P2/5 [8]. This sets restoration requirements depending on the maximum demand of the load group being considered. In addition, since vesting of the U.K.

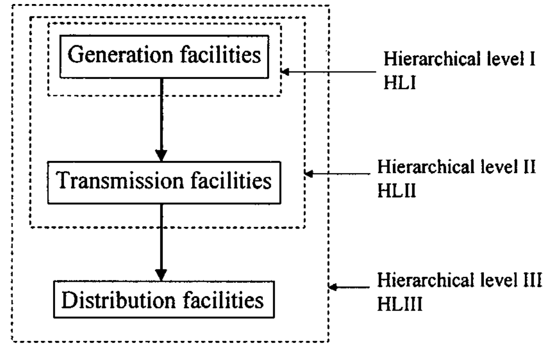

Fig. 1. Hierarchical levels.

electricity supply industry (ESI) in 1990, regional electricity companies (REC's) have been expected to conform to sets of Guaranteed Standards [9] of service with penalty payments having to be made if these are violated. However, in systems that are disaggregated, and particularly those that are owned or operated by private industry, there is also a fundamental need for all the individual parties (generators, network owners, network operators, and energy suppliers) to know the quality of the system sector or subsector for which they (and their shareholders) are responsible. Their perspectives are different and so can be their interests and the benefits they derive. Hence, the information required by each of the parties involved is different. Therefore, there is now a need for a range of reliability measures, the actual measure being dependent on whether it is for the use of generators, network owners, network operators, energy suppliers, or the actual end-customers.

In order to review the functionality of a power system and the way this reacts with reliability, the concept of hierarchical levels has been introduced [10], as shown in Fig. 1. The first level (HLI) relates to generation facilities, the second level (HLII) refers to the integration of generation and transmission, and the third level (HLIII) refers to the complete system including distribution. This structure applied for several decades following the integration of the generation entity into large-scale and frequently remote sources.

However, it needs to be reassessed due to two effects. First, generation is now divided between a number of independent generators who compete with each other and need to retain confidentiality about their investment and operating decisions. Centrally planned generation is therefore becoming a thing of the past and trends about future needs are generally provided by a central body without any formal decisions being made.

Second, the HL structure implies that all generation delivers energy through the transmission system whereas an increasing amount of individually small-scale generation embedded or distributed within distribution systems is now playing a significantly developing role. This has an impact on both the transmission and central generators since the load profiles seen at bulk supply points will change and so will the power flows in the transmission networks. Consequently, conventional generators will sell less energy and might be forced to operate outside optimum points

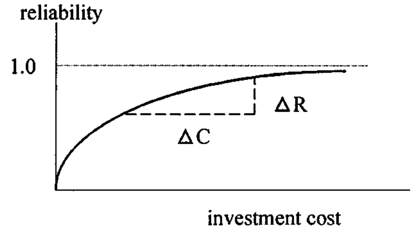

Fig. 2. Incremental cost of reliability.

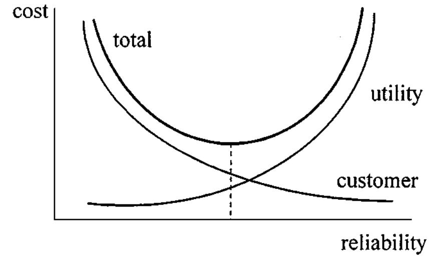

Fig. 3. Total reliability costs.

because of the necessary load regulation action needed to compensate for random fluctuations in the output of the embedded generation.

An extremely important aspect is that reliability levels are interdependent with economics [11] since increased investment is necessary to achieve increased reliability or even to maintain reliability at current and acceptable levels. This concept is illustrated in Fig. 2 which shows the change in incremental cost of reliability ΔR with the investment cost ΔC needed to achieve it. It is therefore important to recognize that reliability and economics must be treated together in order to perform objective cost-benefit studies. This is of considerably growing interest particularly now that financial implications of planning and operating decisions are of great significance to, not only end-customers, but also to investment bankers, shareholders, and regulators. In fact, it has been widely suggested that all economic cost and worth considerations will be determined by the "market" and "market forces." However, how the market will drive reliability and the worth of reliability is not yet defined, nor reasonably understood, at this time and remains very fluid as it continues to evolve. Therefore, we have limited our considerations on this aspect of worth to specific and well-understood concepts.

One such important issue is the customers' evaluation of worth of supply: information relating to customer outage costs and their application is now widely available and understood. Issues associated with this aspect are developing rapidly and several topics are discussed later. However, it is worth noting at this stage that several countries are already imposing financial penalties on suppliers who do not provide a satisfactory service. For instance, one of the guaranteed standards of service in the U.K. [9] is that service must be restored within 24 h of an interruption, otherwise a payment (1998 levels) of £40 to domestic customers and £100 to nondomestic customers must be made on request with a further £20 for each subsequent 12 h of nonrestoration. In 1997/1998, a total of 15 355 guaranteed standards payments and 30 791 *ex gratia* payments were made [9] for inadequate restoration involving a total payment of £3 370 134. These payments were associated with a particularly bad winter and only 167 such guaranteed standards payments were made in 1996/1997. However, these levels indicate that economic methods for reducing the number of violations are very worthy of consideration. Also, Norway has a penalty system in operation in which the 1997 compensation rates were 16 NOK/kWh of energy not supplied for long interruptions and 8 NOK/kW of power interrupted for short interruptions.

IV. Reliability Cost and Reliability Worth

A. Concepts

As briefly discussed above, reliability levels are inter-dependent with economics since increased investment is necessary to achieve increased reliability or even to maintain it at current and acceptable levels (Fig. 2). As discussed in [11], however, this is only part of the concept of reliability economics. In addition to the investment cost required to achieve a certain level of reliability, there is also a need to consider the outage costs associated with each level. The complete consideration of reliability economics therefore includes two aspects now generally known as "reliability cost" and "reliability worth." Reliability cost is considered to be the investment needed to achieve a certain reliability level, whereas reliability worth is considered to be the monetary benefit derived by the supplier and customer of such an investment. Both values can be measured in terms of relative or incremental changes, or in terms of absolute values. However, although the value of reliability cost is relatively easy to define, reliability worth is much more problematical since some costs are quantifiable in terms of actual costs, while others are subjective and depend on various qualitative factors such as inconvenience and irritation factors. In addition, there are increasing views that reliability worth will be driven by the market and that the formulation of reliability worth should reflect how system outages affect the market. However, since this is ill-defined and not fully understood at this time, we have only concentrated on the customers' perception of reliability worth, and this is the focus of all the following discussion.

From the above concept flows the well-known relationship shown in Fig. 3, in which a so-called optimum level of reliability can be deduced. Although the concept of optimum reliability may be an ultimate and worthy goal, it can only be achieved at best in slow steps. First, it requires an assumption that the measures, reliability, and economics, can be obtained in absolute terms, whereas in reality, all the measures are generally relative. Second, most of the customers' assessment of outage costs are perceptions of worth rather than absolute values.

The most demanding part of this reliability cost/reliability worth assessment is associated with deducing the outage costs. Many assessments have been made in the past, the basis of which are detailed in [12]. More recently, very extensive sets of surveys and analyses have been conducted in Canada by the University of Saskatchewan [13]–[15]

Table 1
Typical SCDF's from Canada

sector	interruption duration				
	1 min	20 min	1 h	4 h	8 h
SCDF, C$/kW					
large users	1.005	1.508	2.225	3.968	8.240
industry	1.625	3.868	9.085	25.163	55.808
commercial	0.381	2.969	8.552	31.317	83.008
agriculture	0.060	0.343	0.649	2.064	4.120
residential	0.001	0.093	0.482	4.914	15.690
govt & inst	0.044	0.369	1.492	6.558	26.040
offices	4.778	9.878	21.065	68.830	119.160

and in the U.K. by UMIST [16]–[19]. These surveys have provided outage cost assessments by different classes of customers from their expected or perceived interruption costs for outages of varying durations, frequencies, and occasions.

The main approach used for residential customers was the preparatory action method (PAM) in which customers are asked to choose from a list the likely mitigating actions they would take to alleviate the impacts of interruptions in their electricity supply. The costs associated with the actions are presented in the questionnaire alongside the list of actions. The approach used for nonresidential sectors allowed respondents to fill out, for each interruption duration presented, the costs corresponding to the cost elements relevant to a customer category. The full details of the methods are described in [12]–[19].

B. Customer Worth Assessments

Several steps are involved in translating customer outage cost data into information useful for predicting the benefit of reliability improvements. The main steps are:

1) Values of the perceived customer interruption costs (CIC) for the various interruption durations are obtained using the survey.
2) The CIC's are normalized by dividing the costs by either the annual energy consumed or the peak demand.
3) These normalized costs are weighted either by annual energy consumed or by peak demand to give the customer sector values. Both normalized sets are referred to as sector customer damage functions (SCDF's) [12], defined as the sector's normalized costs due to supply interruptions expressed as a function of interruption duration for the customer mix supplied. In effect, they represent the costs an average consumer in a sector would incur per MWh consumed annually or per kW of peak demand. Typical SCDF's from the Canadian and U.K. surveys are shown in Tables 1 and 2. An important point to note is that the raw data (CIC) are obtained as the cost per "interruption," not per "kW interrupted" nor per "kWh not supplied." Therefore, these SCDF's are not the "cost/energy not supplied." This has caused some misunderstanding and some misuse of the values quoted.

Table 2
Typical SCDF's from the U.K.

sector	interruption duration						
	mom	1 min	20 min	1 h	4 h	8 h	24 h
SCDF, £/MWh							
residential			0.06	0.21	1.44		
commercial	0.46	0.48	1.64	4.91	18.13	37.06	47.58
industrial	3.02	3.13	6.32	11.94	32.59	53.36	67.10
large user	1.07	1.07	1.09	1.36	1.52	1.71	2.39
SCDF, £/kW							
residential			0.15	0.54	3.72		
commercial	0.99	1.02	3.89	10.65	39.04	78.65	99.98
industrial	6.15	6.47	14.27	25.26	72.22	120.11	150.38
large user	6.74	6.74	6.86	7.18	8.86	9.71	13.35

4) Finally, the SCDF values are appropriately weighed in proportion depending on the number and mix of customers to give a cost function for a particular load point, feeder, service area, or system. The series of values, for the range of durations studied, form the composite customer damage function (CCDF) for the associated part of the network and, unlike the SCDF, is system dependent. This CCDF is defined as the normalized costs due to power supply interruptions expressed as a function of the interruption duration for the customers and mix in the particular service area [12].

Two specific cost functions that can be deduced from these damage functions are the customer outage costs (COC's) associated with a particular part of the system, and the value of lost load (VoLL) [18] or interrupted energy assessment rate (IEAR) [20]. To our knowledge, the VoLL is used in the U.K. [18] and Australia [21] and IEAR in Canada [20]:

1) The CCDF's can be used to calculate the COC perceived at a particular load point or in a particular part of a system before and after a reinforcement scheme is considered. The difference in the COC's represent the relative benefits of alternative reinforcement schemes.
2) The SCDF's can be converted into the global indexes of VoLL [18] or IEAR [20]. These are relative worth values expressed in £/kWh or $/kWh and form valuable indexes for comparing alternatives at the global HLI and HLII levels.

Applications of both functions are described in later sections of this paper.

C. Calculation of COC's

Although there are several methods, the principle one for deducing the COC is as follows. First, a knowledge of the average failure rate (λ) and the average duration of interruption (r) is required. These values can be obtained using analytical techniques, such as those reviewed in a later section. These reliability indexes must then be combined with the cost model. Assuming busbar j to be a load point in a network

Table 3
Typical VoLL Values

weighting by	VoLL	VoLLs in £/kWh not supplied			
		REC A	REC B	REC C	combined
energy consumed	EVoLL	9.36	12.30	11.53	10.88
	VoLL [1]	18.60	20.21	20.79	18.25
number of customers	EVoLL	2.10	2.36	3.29	2.68
	VoLL [1]	2.10	2.59	3.19	2.64

where VoLL [1] refers to value of lost load for 1 h
REC refers to different Regional Electricity Companies

consisting of b busbars, the annual COC due to supply interruptions at the busbar (COC$_j$) and in the network (SCOC) are given by

$$\text{COC}_j = (\Sigma_y E_{jy}) \cdot C_j(r_j) \cdot \lambda_j \tag{1}$$

$$\text{SCOC} = \Sigma_j \ \text{COC}_j \tag{2}$$

where E_{jy} is the energy consumed by sector y customers at busbar j and $C_j(r_j)$ is the value of the SCDF at busbar j for interruption duration r.

D. Calculation of VoLL

The following briefly reviews the calculation of VoLL [18]. A similar approach is used to calculate IEAR [20]. Since VoLL is said to represent the value an average consumer puts on an unsupplied kWh, it can therefore be assessed by relating the total COC for the system to the expected energy not supplied to that system. The method uses two steps: the first establishes the VoLL values for the durations studied while the second calculates the expected value of VoLL (EVoLL) taking into account the distribution of the outage durations. Typical values are shown in Table 3.

Step 1: Calculating the VoLL function

$$\text{VOLL}(r_i) = C(r_i)/(r_i \cdot LF) \tag{3}$$

where LF refers to the load factor of the customer mix considered.

Step 2: Calculating the expected VoLL

$$\text{EVOLL} = \Sigma_i \text{VOLL}(r_i) \cdot p(r_i) \tag{4}$$

where $p(r_i)$ is the probability of outage duration i.

V. Generation Capacity

A. Generation Capacity Requirements

During planning of global generation systems, it is necessary to determine how much capacity needs to be installed in order to satisfy the expected demand at some point in time in the future and to provide sufficient reserve to perform corrective and preventive maintenance. The ability to move the energy to bulk supply points or customers is not considered at this stage. Historically, the reserve capacity has been set equal to a percentage of the expected load, or equal to one or more of the largest units, or a combination of both. Prior to the restructuring of the ESI, which was described previously, these deterministic criteria were largely being replaced by probabilistic methods that were able to respond to the stochastic factors influencing the reliability of the system. Following restructuring, these applications have declined.

Instead, the construction of generating plant is now more dependent on market forces with planning decisions being taken on the basis of expected profit returns. Also, the main criterion would seem to be the maximization of profits rather than the minimization of costs. The assumption within the market is that, as margins reduce and the consequential energy prices increase, construction of new generating plant will be encouraged. The process by which the market will respond in this respect is not well defined and it is too much in its infancy to predict how it will progress.

However, it is our view that the approaches described in this section will be needed in the future, particularly by bodies who should become responsible for overall management of energy resources and related strategy and policy decisions. Therefore, a need to understand the assessment of generation risk remains of importance.

B. Probabilistic Criteria and Indexes

The probabilistic criteria and indexes used in HLI studies include loss of load probability (LOLP), loss of load expectation (LOLE), loss of energy expectation (LOEE), expected energy not supplied (EENS), expected unserved energy (EUE), energy index of reliability (EIR), energy index of unreliability (EIU), and system minutes (SM):

1) *LOLP*—This is the oldest and most basic probabilistic index. It is defined as the probability that the load will exceed the available generation. Its weakness is that it defines the likelihood of encountering trouble but not the severity; for the same value of LOLP, the degree of trouble may be less than 1 MW or greater than 1000 MW or more. Therefore, it cannot recognize the degree of capacity or energy shortage.
2) *LOLE*—This is probably the most widely used probabilistic index in deciding future generation capacity. It is generally defined as the average number of days on which the daily peak load is expected to exceed the available generating capacity. Alternatively, it may be the average number of hours for which the load is expected to exceed the available capacity. The index therefore indicates the expected number of days (or hours) for which a load loss or deficiency may occur. It has the same weaknesses that exist in LOLP.
3) *LOEE*—This is defined as the expected energy that will not be supplied due to those occasions when the load exceeds the available generation. It is a more appealing index than LOLE because it encompasses severity of the deficiencies as well as their likelihood. Therefore, it reflects risk more truly and is likely to grow in popularity as power systems become more

energy limited due to reduced prime energy and increased environmental controls. LOEE is essentially the same as EENS or EUE or similar terms.

4) *EIR and EIU*—These are directly related to LOEE which is normalized by dividing by the total energy demanded. This ensures that large systems and small systems can be compared on an equal basis and chronological changes in a system can be tracked.
5) *System Minutes (SM)*—This index is again related to LOEE which is now normalized by peak demand. A weakness is that it introduces an index having time as the units. This has no conception to real time but would have been the annual unavailability if all energy interruptions only occurred at peak load. In reality, the annual unavailability is greater than the values given by system minutes.

It must be stressed that all the above measures are expectations, i.e., they are not deterministic values, but only the average value of a probability distribution. Also, these indexes are not measures actually seen by the end-customers, but are really relative measures by which alternative planning scenarios can be objectively compared.

C. Consideration of Embedded Generation

Two scenarios can be studied at HLI depending on which energy sources are included in the assessments; first, by neglecting the generation sources embedded in the distribution system, and second, by including them. Since HLI studies ignore the network completely and since embedded generation contributes to the energy supply, it seems appropriate to include such sources in HLI assessments. Problems in doing so are that they are often not scheduled by system dispatchers, some types (e.g., wind, solar) are not easily predicted, and often they are not permitted to generate if they become disconnected from a bulk supply point (BSP). Therefore, their outputs are not easily incorporated into the assessments because of these dependency factors. Also, their present contribution to the total system demand is relatively small. For these reasons, although it is wise and probably essential to include embedded generation in some way when making long-term strategic energy assessments, it may be preferable to neglect such sources when performing normal or routine HLI studies.

D. Reliability Evaluation Techniques

Two main approaches exist for evaluating the reliability of generation capacity; 1) analytical and 2) simulation.

Analytical techniques evaluate the reliability indexes from a mathematical model using mathematical solutions. Therefore, for a given model and a given set of input data, a specific solution is produced. The main problem with this approach is the frequent need to make simplifying assumptions and approximations, the effect of which is often unknown. Also, it is often only possible to evaluate expected values and not the underlying distributions.

Simulation techniques, often known as Monte Carlo simulation, estimate the indexes by simulating the actual process and random behavior of the system. These techniques can themselves be divided into two categories: 1) nonsequential and 2) sequential. Nonsequential simulation considers each time interval independently and therefore cannot model time correlations or sequential events. The sequential approach, however, takes each interval (usually 1 h) in chronological order.

Simulation is not needed generally to analyze thermal systems, although sequential simulation is very useful in assessing systems having a time dependent history such as hydro systems containing reservoirs and pumped storage. Both sequential and nonsequential simulation can be very useful in modeling more complex systems, such as at the HLII level.

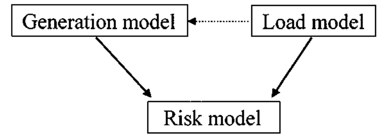

Fig. 4. Conceptual risk model at HLI.

E. Modeling Approach

The concept for all HLI analytical studies is shown in Fig. 4, in which a generation model and a load model are combined (i.e., convolved) to give a risk model. This principle applies to all approaches; the difference is not the concept, only the method of application.

The generation model is usually treated independently of the load model, i.e., convolved as shown by the solid lines in Fig. 4. A few approaches link the load and generation models in order to reflect the cyclic nature of generation units with load. However, decisions regarding whether the generation capacity can satisfy the system demand with reasonable risk can usually be achieved satisfactorily without introducing these additional complexities.

The analytical generation model is based on a capacity outage probability table which lists system capacity states in increasing order of capacity on outage, together with the probability of occurrence of each of these states. There are many ways of creating and manipulating this table [22], [24] but the essential objectives and outcomes are the same.

The load model used in an analytical approach is usually either the daily peak load variation curve (DPLVC) or the load duration curve (LDC). The DPLVC includes only the peak loads of each day for the period being considered, e.g., whole year, winter, particular month, etc., whereas the LDC includes the hourly (or half-hourly) variation of the load in this period.

The risk is evaluated by combining the generation and load models as follows. Each capacity outage state C_k having a probability p_k is superimposed on the load model, as shown in Fig. 5. The number of time intervals (days with DPLVC and hours with LDC) for which the load exceeds the remaining generation can be deduced. This is t_k. The energy not supplied by the remaining generation can also be deduced from the LDC. This is the area E_k. Finally, the peak load L_p is the ordinate intercept of the DPLVC and LDC and the

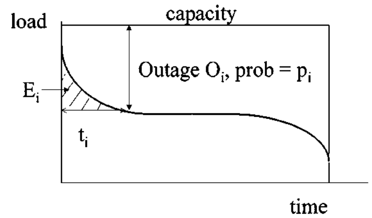

Fig. 5. Risk assessment at HLI.

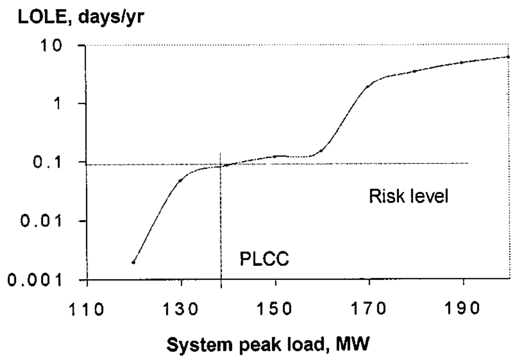

Fig. 6. Typical risk characteristic.

energy demanded E is the total area under the LDC. These values give [22]:

$$\text{LOLE} = \Sigma\, t_k \cdot p_k$$
$$\text{LOEE} = \Sigma\, E_k \cdot p_k$$
$$\text{EIU} = \text{LOEE}/E$$
$$\text{EIR} = 1 - \text{EIU}$$
$$\text{SM} = (\text{LOEE}/L_p) \cdot 60.$$

It is worth noting two points:

1) The frequency and duration of encountering deficiencies can also be evaluated [22]. However, these indexes have never been used to any great extent in practice and therefore are not included in this review.
2) LOEE can be transformed into an expected outage cost if the value of energy not supplied is known. This value is given by IEAR and VoLL.

The above process is conceptually very simple. The application becomes complex only in terms of developing the two models and taking into account more of the random factors such as load forecast uncertainty, maintenance effects, and energy limitations. These factors are outside the scope of this paper, but existing techniques for including them are available [22], [23].

F. Generation Expansion Planning

It is self evident that the risk increases as the load increases. A typical characteristic is shown in Fig. 6. If a maximum risk index is specified, then the maximum peak load that can be supported by the generation system can be determined. This value is known as the peak load carrying capability (PLCC), shown in Fig. 6 for a specified risk level of R_L. The variation of PLCC with R_L can be used as a measure

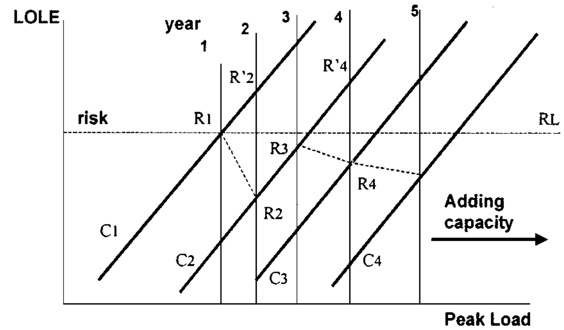

Fig. 7. Possible generation expansion plan.

to determine by how much the load can be allowed to grow without creating excessive risk. This concept can be extended to generation expansion planning, as illustrated in Fig. 7. The abscissa shows the peak load P_1, P_2, P_3, expected in years 1, 2, 3, etc. The present installed capacity gives the risk curve C_1. The present risk (year 1) is therefore R_1. The maximum acceptable risk level is specified as R_L and assumed to be equal to R_1. The expansion procedure is as follows:

1) In year 2, the risk increases to R_2' which exceeds R_L. Additional capacity is required which produces the new risk curve C_2, and reduces the risk to R_2.
2) In year 3, the risk increases to R_3 which is less than R_L and no further action is required.
3) In year 4, the risk increases to R_4' which again exceeds R_L. Again capacity is needed which produces the risk curve C_3 and lowers the risk to R_4.
4) This procedure continues for the complete planning period.
5) Alternative expansion plans can be studied using different capacity additions, advancing or delaying capacity additions, accounting for variations in expected loads, etc.
6) The present worth of each plan can be assessed and compared.

This procedure, while not being entirely definitive, provides very useful objective information which enhances the decision-making process. However, in all cases, an economic assessment is necessary; a present worth evaluation for the investment cost, and an estimation of the change in reliability worth.

G. Reliability Worth Assessments

Reliability worth assessments can play an important role in HLI. Two examples are described below.

1) *Pool Payments*—VoLL and LOLP are both used as part of the settlement procedure associated with selling to and buying from the pool[1] in the U.K. In this case, the pool input price (PIP) [25] is based on the concept of conditional probability [26] and:

$$\text{PIP} = \text{SMP} \cdot (1 - \text{LOLP}) + \text{VoLL} \cdot \text{LOLP}$$

[1]The pool operates as the trading mechanism between buyers and sellers of electricity. It is intended to be replaced by bilateral trading agreements late in 2000.

where

SMP $=$ the system marginal price (£/kWh)

VoLL $=$ the estimated value of lost load.

VoLL was set at £2.000/kWh in 1990, to be increased annually by the rate of inflation (RPI). In 1998, it was £2.599/kWh. The value of LOLP is evaluated as the probability of the declared available generation not satisfying the expected load at each half hour on the day in question. The purpose of the second term in the cost expression was to create a capacity payment which was intended to encourage investment in new plant when the system LOLP began to increase. There is considerable doubt whether it can operate in this way.

In a similar but not identical approach, VoLL has been used in Australia by the Victorian Power Exchange to cap the price of generated energy. For some time , it has been set at A$5/kWh, but following a similar survey to that conducted in Canada and the U.K., it has been reported [21] that a proposal to increase it to A$25/kWh has been made.

2) *Comparison of Alternatives*—Reliability worth assessments can be incorporated into expansion planning by calculating the expected outage cost associated with the different planning alternatives. Consider a simple five-unit system, each unit of 50 MW with a forced outage rate (FOR) of 0.01, and a straight line load model with a peak load of 170 MW and a minimum load of 68 MW. An expansion plan of adding 10 MW gas turbines is being considered. Assuming a fixed investment cost proportional to the number of gas turbines added and an IEAR of $3.83/kWh, then the expected outage cost (ECOST) can be evaluated from

$$\mathrm{ECOST} = \mathrm{IEAR}^{*}\mathrm{LOEE}.$$

This will give the results shown in Table 4 [22].

It is evident that, while the investment cost increases with increased units, the outage cost decreases giving an optimum value with one additional unit added. In practice, a more extensive economic assessment is needed but this example illustrates the principle and justifies the concept of an optimum value of reliability taking into account the worth end-customers place on their supply of electrical energy.

Table 4
ECOST Comparisons

units added	capacity MW	reserve margin %	LOEE MWh/yr	ECOST \$M/yr	fixed cost \$M/yr	total cost \$M/yr
base	200	17.7	313.8	1.202	0.0	1.202
+1	210	23.5	74.3	0.284	0.5	0.784
+2	220	29.4	40.9	0.157	1.0	1.157
+3	230	35.3	19.5	0.075	1.5	1.575
+4	240	41.2	6.3	0.024	2.0	2.024
+5	250	47.1	1.2	0.005	2.5	2.505

VI. Composite Generation and Transmission Systems

A. Background

The second hierarchical level (HLII) shown in Fig. 1 is frequently referred to as a composite (generation and transmission) system or a bulk power (or transmission) system. The purpose of assessing the reliability of the power system at this level is to estimate the ability of the system to perform its function of moving the energy provided by the generation system to the bulk supply points (BSP). In the U.K., this refers to that part of the power system containing the 400/275 kV grid system and the sources of generation connected to it. The distribution networks are not considered at this level.

Assessment of composite system reliability is very complex since it must consider the integrated reliability effects of generation and transmission. These two entities cannot be analyzed separately at this level. To do so could create misleading results and conclusions. This does not mean they have to be owned by the same company, but it is essential that one body has the role of coordinating the planning and operation. In the U.K., this is the responsibility of the National Grid Company (NGC); in other countries, responsibilities may be divided between a network owner and an ISO, depending on how the system ownership is structured.

Composite systems have many inherent complexities and further models and evaluation techniques are still being developed [1]–[7]. It is also important to recognize that the impact of the market at this level is much more questionable since competition in transmission is impractical. For this reason alone, the transmission sector is likely to remain highly regulated in most ESI, although the form of regulation seems to differ significantly from one system to another. This paper therefore outlines alternative approaches rather than describing prescribed approaches and indexes. This is intended to make the reader aware of the concepts and present trends in these important developments.

B. Requirements of Composite Systems

The function of a composite system is to produce electrical energy at the generation sources and move this energy to the BSP. The ability to generate sufficient energy to satisfy the demands at the BSP, and to transport it without violating the system operational constraints, can be measured by one or more reliability indexes.

Bulk transmission facilities must not only provide adequate transmission capacity to ensure the demand is satisfied and that voltage, frequency, and thermal limits are maintained, but must also be capable of maintaining stability following fault, switching, and other transient disturbances. The transmission facilities must, therefore, satisfy [10] both static (known as adequacy) and dynamic (known as security) conditions.

The concept of adequacy is generally considered to be the existence of sufficient facilities within the system to satisfy the consumer demand. These facilities include those necessary to generate sufficient energy and the associated transmission that transport the energy to the actual load points. Therefore, adequacy does not consider system disturbances. Security, on the other hand, is considered to relate to the ability of the system to respond to disturbances arising within that system. These are considered to include conditions causing local and widespread effects and the loss of major generation and transmission facilities.

It is evident from the above definition that adequacy is used to describe a state of a system in which the entry to and departure from that state is ignored. The state is then analyzed using a power flow model and deemed adequate if all system requirements including the load, voltages, VAR requirements, etc., are all fully satisfied. The state is deemed inadequate if any one or more of the power system constraints are violated. This concept is usually well recognized and accepted. The only additional consideration that may sometimes be included is that an otherwise adequate state is deemed to be adequate if and only if, on departure, it leads to another adequate state, and deemed inadequate if it leads to a state which itself is inadequate in the sense that a network violation occurs. This consideration creates a buffer zone between the fully adequate states and the other obviously inadequate states. Such buffer zones are also known as alert states [27] and are discussed in more detail later.

This concept of adequacy considers a state in complete isolation and neglects the entry transitions and the departure transitions as causes of problems. In reality, these transitions, particularly entry ones, are fundamental in determining whether a state can be static or whether the state is simply transitory and very temporary. This leads automatically to the consideration of security and consequently it is evident that security and adequacy are interdependent and part of the same problem.

Power system engineers tend to relate security to the dynamic process that occurs when the system transits between one state and another state. Both of these states may themselves be acceptable if viewed only from adequacy, i.e., they are both able to satisfy all system demands and all system constraints. However, this ignores the dynamic and transient behavior of the system in which it may not be possible for the system to reside in one of these states in a steady-state condition. If this is the case, then a subsequent transition takes the system from one of these so-called adequate states to another state which itself may be adequate or inadequate. In the latter case, the state from which the transition occurred would be deemed adequate but insecure. Any state which can be defined as either inadequate or insecure is clearly a system failure state, and contributes to system unreliability irrespective of designation. Present reliability evaluation techniques generally identify failure states as those states in which inadequacy only has been determined. They therefore ignore or neglect adequate states in which insecurity exists. This problem has been further discussed in two CIGRE Reports [28], [29].

It should be noted that, although assessment of security is of great importance, virtually all of the techniques available [1]–[7] at this time relate to adequacy assessment: probabilistic security assessment is very much in the research domain. This paper is, therefore, restricted to adequacy considerations only. Even with this restriction, planning decisions can be improved considerably with the additional objective information derived from adequacy assessments. In order to take into account the important effect of dynamic issues on reliability, *ad hoc* approaches are frequently used in practice to incorporate dynamic effects through the reduction of various constraints such as export-import limits.

C. Probabilistic Criteria and Indexes

In order to compare the predicted performance of a system with actual operating experience, it is desirable that the predicted indexes and past performance measures should be basically the same. The present problem is that the predicted indexes are usually only adequacy-based, whereas, the past performance measures are reliability (adequacy/security) based.

It should also be noted that two main sets of indexes can be calculated: 1) system indexes and 2) load point indexes. Considerable debate has centered on the comparative merits of these two types of indexes. This is unfortunate because they are complementary, not alternatives, and each serves an entirely different purpose.

System indexes are global indexes representing the behavior of the overall system. They can quantify the likelihood of encountering trouble somewhere (undefined) in the system, the total energy not supplied to the system, etc. For instance, in the case of the simple 5-bus system [30] (known as the RBTS) shown in Fig. 8, the system index representing energy not supplied is the total summated energy not supplied to any of the load buses irrespective of the cause and the location of the deficiency.

These system indexes, past and predicted, are extremely valuable for decisions regarding global observations and overall energy management. They can be used to:

1) track the chronological changes in system behavior;
2) predict and monitor the result of changing system operational strategies; and
3) compare the performance of different systems and different areas within a system.

These merits are not in question. However, the system indexes are not appropriate for identifying the effect of individual reinforcement schemes, for instance, the effect of adding a line between buses 4 and 5 on the reliability at bus 5 of the system, shown in Fig. 8. This is particularly the case for large practical systems when the change in the values of the system indexes resulting from a single reinforcement scheme is usually very small compared with the other contributions in the overall system. They can, therefore, be very insensitive to such changes. Also, since a particular network reinforcement scheme is generally intended to affect the response at a specific BSP, the "before" and "after" set of indexes at this BSP are desirable. This can only be objectively gauged from the load point indexes. The main problem in evaluating load point indexes is how or where to allocate system deficiencies, e.g., at which BSP should energy be curtailed if curtailment is needed. These may be difficult questions but are still necessary if objective decisions and cost-benefit analyses are to

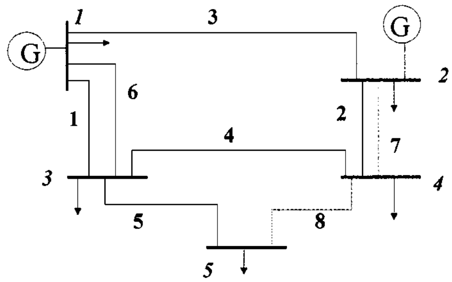

Fig. 8. 5-bus RBTS for HLII studies.

be made. The evaluation does require a clear knowledge of likely system operational curtailment policies.

A typical set of load point indexes and system indexes [22] are listed in Figs. 9 and 10, respectively. There are several points to note regarding these indexes:

1) The lists are not comprehensive. Individual utilities or regulatory bodies may find the need for alternative indexes in order to reflect particular system conditions and requirements.
2) All of the indexes are not usually required. Again, individual utilities and regulatory bodies may require only a few, even one, for their decision-making process.
3) There is no general consensus which indexes are the most appropriate.
4) The indexes as quoted can be assessed on one of several bases:

   The study period is one year when the appropriate load, network, and generation models provide annual indexes.

   The study is for a particular period only, e.g., one season, one month, one week, etc. Appropriate models are needed for each.

   The indexes are calculated for a single load level, usually the system peak load.

In the last two cases, the actual indexes are expressed on the basis of a time period which is clearly less than one year. These indexes can then be scaled up pro rata so that they are expressed on an annual time basis. This creates a set of annualized values which are usually much greater than the true annual indexes and therefore must be treated and interpreted with care. However, expressing them on an annualized basis permits easier comparisons to be made chronologically and between systems.

D. Evaluation Techniques

The two main approaches, analytical and simulation, are both used extensively in the adequacy assessment of composite systems [22], [23], [31]. Both approaches assess the adequacy of a system state using the principle shown in Fig. 11 in a similar way, i.e., both use an appropriate load flow to identify the system deficiencies and to assess the effect of remedial actions. This aspect, therefore, determines the severity of a system state deficiency. The major difference between the two approaches is in the process of selecting states and the way the likelihood and other adequacy indexes are evaluated.

BASIC VALUES
- probability of failure
- expected frequency of failure, f/yr
- expected number of voltage violations
- expected load curtailed, MW
- expected energy not supplied, MWh
- expected duration of load curtailment, h

MAXIMUM VALUES
- maximum load curtailed, MW
- maximum energy curtailed, MWh
- maximum duration of load curtailment, h

AVERAGE VALUES
- average load curtailed/curtailment, MW/curtailment
- average energy not supplied/curtailment, MWh/curtailment
- average duration of curtailment/curtailment, h/curtailment

BUS ISOLATION VALUES
- expected number of curtailments
- expected load curtailed, MW
- expected energy not supplied, MWh
- expected duration of load curtailment, h

Fig. 9. Typical set of load point indexes.

BASIC VALUES
- bulk power interruption index (BPII), MW/MW.yr
- bulk power supply average MW curtailment/disturbance (BPSACI), MW/disturbance
- bulk power energy curtailment index (BPECI), MWh/MW.yr
- modified bulk power energy curtailment index (MBPECI)
- system minutes, m

AVERAGE VALUES
- average number of curtailments/load point
- average load curtailed/load point, MW/load point
- average energy curtailed/load point, MWh/load point
- average duration of load curtailed/load point, h/load point
- average number of voltage violations/load point

MAXIMUM VALUES
- maximum system load curtailed under any contingency condition, MW
- maximum system energy not supplied under any contingency condition, MWh

Fig. 10. Typical set of system indexes.

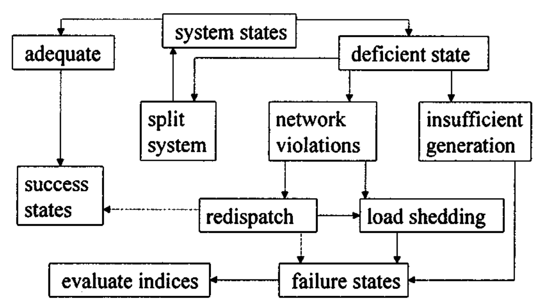

Fig. 11. Concepts of HLII assessment procedure.

The analytical approach generally selects states in an increasing order of the contingency level, i.e., zero outages, first order outages, etc. The process is usually stopped at a particular contingency level or when the state probability becomes less than a specified value. A state is, therefore, assessed only once and the indexes are calculated mathematically from the statistical data defining each state, i.e., probability, frequency, duration, etc.

The simulation approach selects states using the concept of random numbers [32]. States having a greater probability of occurrence are more likely to be simulated and are likely to be simulated several times. The process is stopped either after a fixed number of simulations or on the basis of statistical stopping rules. The expected values of the indexes are determined by averaging the indexes obtained during each simulation. Other statistical indexes such as standard deviation and complete probability distributions can be found similarly from the individual simulation results.

Composite systems containing only thermal generation are often amenable to analytical techniques. The main exception is when information other than average or expected indexes are required, i.e., standard deviations, probability distributions, and confidence limits. Another exception may include large-scale composite systems. In such cases, simulation techniques may be necessary. Some systems, however, cannot be assessed easily with the analytical approach. This includes hydro-systems supported by reservoirs and pumped storage. The inherent complexities of such systems makes the use of simulation, particularly sequential, almost essential (see [1]–[7]).

E. Modeling of Outages

The basic concept utilized in all HLII studies is that a system state is selected and its adequacy is assessed [22]–[24], [31]. This applies to both the analytical and simulation approaches. This can be achieved with the concepts illustrated in Fig. 11 in which a deficiency may be overcome by actions such as redispatch or may require load curtailment. Each system state is composed of a number of components on outage at the same time. The outages that are assessed are combinations of generator outages and of transmission line outages. These outages may be due to failures of the generators and transmission lines themselves or may be outaged due to the failure of other system components. This leads to the following types of outages that should be assessed:

1) independent outages;
2) dependent outages;
3) common mode outages;
4) station originated outages.

In most cases, the likelihood of an outage is enhanced by the occurrence of adverse weather or environment and these effects should also be taken into account. A detailed description together with appropriate evaluation techniques are given in [22].

F. System Reinforcements Studies

It is not possible within the short space of this paper to describe detailed analyses of reinforcement studies of systems. However, it is pertinent to illustrate some of the concepts with the aid of a simple illustrative example. Consider the 5-bus system (RBTS) shown in Fig. 8. The following scenarios are studied:

Case 1) without lines 7 and 8, ignoring common mode failures;
Case 2) with line 7 added;
Case 3) with lines 7 and 8 added;
Case 4) including common mode failures on lines 1 and 6.

A full description of this study and results are given in [22]. A summary of the results is shown in Figs. 12 and 13. These clearly illustrate the effect that the various reinforcement schemes have on individual bus indexes, for instance, note the large change in frequency of interruptions at bus 5 when first line 7 and then line 8 is added. The benefit of each reinforcement can therefore be objectively assessed. In this example, some of the system indexes change quite significantly following individual reinforcements. This is because the system is very small and individual busbars make a significant contribution to the global value.

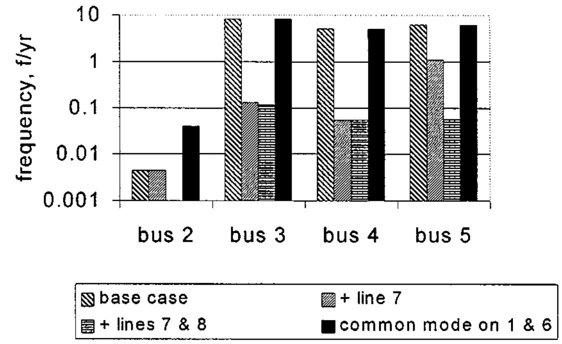

Fig. 12. Load point indexes for 5-bus system.

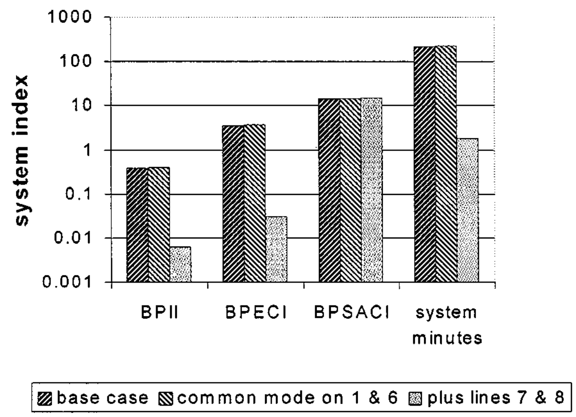

Fig. 13. System indexes for 5-bus system.

G. Inclusion of Deterministic Criteria in Studies

The previous example follows the conventional practice of evaluating a set of load point and system indexes that indicate the likelihood, together with frequency, duration, and other indexes, of a load point or of the system entering states in which the system demand cannot be fully satisfied, i.e., truly inadequate states. However, most electric power utilities use deterministic techniques to assess the reliability in transmission system planning. These generally include the need for the system to be secure against the loss of one or more generating units or transmission lines, i.e., it is expected to operate without violating system constraints or without the need to shed load under a specified set of contingencies. This means that buffer states (known as alert states) exist between fully adequate states (known as normal) and negative margin states (known as emergency states) as discussed previously.

There is growing interest in combining these deterministic considerations with probabilistic assessment in order to monitor the so-called "well-being" of the system [33], [34] and to evaluate the likelihood, not only of entering a complete

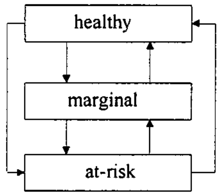

Fig. 14. System operating states.

failure state, but also the likelihood of being very close to trouble. The underlying concept in this consideration is that a set of indexes can be evaluated using conventional reliability assessment but associated with the alert states (called marginal) and the emergency states (called at-risk). These states are shown in Fig. 14.

In the healthy state, all equipment operate within their constraints and the generation is adequate to satisfy all the load demand. In addition, there is sufficient margin such that the loss of any major system component such as generating units and transmission lines, specified by the deterministic criterion, will not result in an operating limit being violated or load curtailed. The criterion will depend on the philosophy of individual utilities. In the marginal state, the system is operating within its limits but no longer has sufficient margin to satisfy the specified deterministic criterion. This means that the loss of some major plant will result in the criterion being violated although the system may still be within limits and no load is actually shed. In the at-risk state, equipment and/or system constraints are violated and/or load is shed. Such states correspond to the inadequacy states enumerated by conventional composite reliability evaluation algorithms. The indexes defining the likelihood, frequency, duration, and load/energy curtailed for each type of state can be evaluated using the conventional probabilistic techniques.

To illustrate the application of this approach, some results obtained [34] for the 5-bus RBTS are shown in Tables 5 and 6.[2]

The results in Table 5 show that the probability of system health decreases as the load increases and that the system margin probability and system risk probability increase. This implies that some contingencies which are located in the healthy region at low system loads move to the margin or even at-risk regions as the load increases. A knowledge of these contingencies, particularly when they move from healthy to marginal, isvery important and would not be identified using conventional probabilistic assessment until they actually move into the at-risk region when they suddenly begin to have a severe effect.

It can be seen from Table 6 that the probability of system health is effectively zero when a line is installed between bus 1 and bus 2; the results being worse than those for the base case. This indicates that the system cannot, in this condition, tolerate a single element outage without violating the healthy state condition. This violation is caused by the overload of line 1 or line 6 as power is transferred from bus 1 to bus 3 through one single line when one of lines 1 and 6 is out of service. The results indicate that the addition of a single line cannot effectively reduce the system risk as the system load grows. This outcome is not easily identified if only at-risk states are considered since the at-risk probabilities do not change to any significant degree.

[2]Although the values in these and subsequent tables are quoted to six decimal places, this is to indicate precision and differences, and should not be assumed to imply accuracy is achievable to this level.

Table 5
Effect of Load Level on Health

load	probability			LOLE
%	healthy	marginal	at-risk	h/yr
40	0.997595	0.002379	0.000026	0.2278
60	0.997325	0.002646	0.000029	0.2540
80	0.973718	0.025991	0.000291	2.5492
100	0.828712	0.162608	0.008680	76.036

Table 6
Effect of Adding Lines on Health

new line	probability		
bus - bus	healthy	marginal	at-risk
2-4	0.827546	0.162450	0.010004
1-2	0.000000	0.988240	0.011760
3-4	0.811907	0.177620	0.010473
3-5	0.811906	0.177616	0.010478
4-5	0.813721	0.175808	0.010471
base case	0.811019	0.178503	0.010478

In the past, system planners and operators have focused their attention on the use of deterministic criteria, albeit acknowledging that power systems behave stochastically. Simultaneously, others have been developing probabilistic assessment tools and approaches. The first approach focuses primarily on the occurrence of marginal states and the second generally on system at-risk states. This well-being approach attempts to bridge the gap between the two approaches by addressing the need to determine the likelihood of encountering marginal system states as well as that of encountering system at-risk states.

It is also worth noting that this well-being approach can equally be applied at HLI in both the adequacy domain and operating reserve area [35], [36]. The importance of bridging the deterministic and probabilistic criteria in the operating or spinning reserve area is of considerable importance.

H. Impact of Embedded Generation

If the BSP of a transmission system supplies a distribution network which does not have any embedded generation, then the demand seen by that BSP is simply the aggregated demand within the distribution systems being supplied. However, if the distribution system contains embedded generation then, not only will the energy demanded from the BSP (and therefore the transmission network feeding it) be reduced by the energy generated within the distribution system, but also the load profile seen by the BSP will change. This can have profound consequences. Since the embedded generation may not always be available, the maximum system demand on the BSP is still the maximum demand that would exist even without the embedded generation. However, since the embedded generation will contribute for much of the time, the average demand seen by the BSP will decrease. Therefore, the skewness and the variance of the demand seen at the BSP will increase, which will impose increased, and potentially considerable, variation on the demand at the BSP and consequently on the power flows through the transmission system feeding the BSP.

This impact can be assessed using conventional approaches for conducting HLII assessments. In order to do this, it is necessary to quantify the actual load profile seen at the BSP. This can be an output calculation from a reliability assessment conducted on the distribution system. In brief, if a time sequential estimate is made of the output of the embedded generators and these are convolved with the time sequential demands of the consumers in the distribution system, then a time sequential estimate of the remaining demand on the BSP can be made. This modified load profile can then be used in the HLII reliability assessment, which will provide a way of:

1) comparing the transmission system performance before and after including embedded generation;
2) estimating the impact of revised power flows; and
3) indicating the effect of new forms of generation on existing generators.

The procedure of using the output of a distribution system assessment as input into HLII assessments is a fundamentally different approach since previously the HL procedures were used top-down so that the output of upper HL levels were used as input to lower levels, not vice versa. However, it does confirm the versatility of the HL concept. In order for this approach to work, however, it is evident that the output of embedded generation as well as customer loads must be predicted or forecasted.

Although HLII reliability assessments have not been done routinely in the past, the competitive nature of the present ESI and the extended use of embedded generation suggests that such assessments could be of increasing importance. The main reason is that all the individual and competing parties involved in energy trading and scheduling should be treated fairly and impartially, which therefore requires all technical assessments to be conducted objectively and transparently. Also quantitative reliability assessments are able to provide the information necessary to conduct relevant technical and economic audits.

I. Reliability Worth Assessments

Reliability worth assessments are as equally important at HLII as they are at HLI and HLIII. The approaches that can be used fall into one of the following two categories:

1) Similar to the HLI assessments described previously in which estimated outage costs are evaluated using the expected energy not supplied and an appropriate value of IEAR or VoLL.

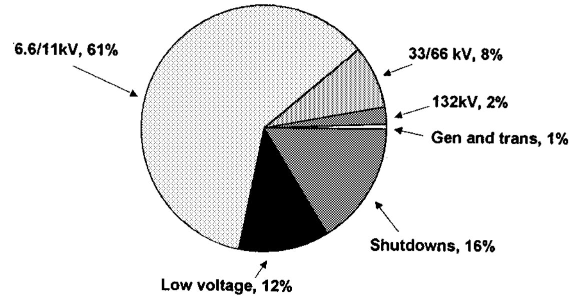

Fig. 15. U.K. 10 yr average Availability and Security.

2) Similar to HLIII or distribution system assessments in which load point or system outage costs are evaluated using the approach described previously and applied to specific systems later.

VII. DISTRIBUTION SYSTEMS

A. Background

Although consideration of HLIII would enable the effect of generation, transmission, and distribution on individual customers to be evaluated and compared, this is usually impractical because of the enormity of the problem. Instead predictive assessments are usually done for the distribution functional zone only. This is acceptable for the following reasons.

1) Distribution networks generally interface with the transmission system through one supply point, and the load point indexes evaluated in the HLII assessments can be used if needed as input values for the reliability evaluation of a distribution system.
2) Generally 80%–95% of customer unavailability can be accounted for by the distribution network. Typical results are shown in Fig. 15 which represent the U.K. 10 yr average [37] for Availability and Security (see later definitions).

B. Requirements of Distribution Systems

The technical function of a distribution system is to take energy from bulk supply points and deliver it to individual customers within certain quality constraints of voltage, frequency, harmonics, flicker, etc. It is also expected to achieve this with a reasonable level of reliability, i.e., to keep the number and duration of outages reasonably low. This can be quite difficult to achieve economically particularly at the lower voltage levels and in rural areas, because the system generally consists of single radial overhead lines which are exposed to adverse environmental conditions. They are therefore prone to failure and frequently lengthy outage times. Superficially, the inclusion of local generation would seem to provide a remedy for reducing the number and duration of outages experienced by customers but, although this is always possible theoretically and could be so in some systems, in others it will not provide such immediate benefits because they are frequently shut down when the system is disconnected from the main BSP for safety reasons.

Reliability assessments of distribution systems, particularly those without embedded generation, are generally relatively simple because the system is often either radial, or operated radially, and the problem of security which occurs at HLII does not normally exist.

C. Probabilistic Criteria and Indexes

Most utilities collect measures of how distribution systems perform during the operational phase (e.g., [37], [38]). Historically, these are customer-related measures evaluated from system interruption data. The basic indexes are failure rate λ, average outage duration r and annual unavailability U at individual load points. A set of system indexes [22] can be deduced using customer and load data. The terms used to define these system indexes vary but are conceptually the same as the following.

1) System average interruption frequency index (SAIFI): In the U.K., this is equivalent to the term, SECURITY, which is defined as the number of interruptions per 100 connected customers per year [37].
2) System average interruption duration index (SAIDI): In the U.K., this is equivalent to the term, AVAILABILITY, which is defined as the number of customer minutes lost (CML) per connected customer per year [37].
3) Customer average interruption frequency index (CAIFI): In the U.K., this is equivalent to the number of CML per interruption.
4) Customer average interruption duration index (CAIDI).
5) Average service availability index (ASAI).
6) Average (expected) energy not supplied (AENS/EENS).

These indexes are excellent measures for assessing how well a system has performed its basic function of satisfying the needs of its customers. The indexes can be calculated for the overall system or for subsets of the system depending on the requirements for the performance measures. Theoretically, predicting the same indexes for future performance is relatively straightforward. However, it does require realistic component data that includes relevant failure rates and restoration times. These are not easily obtained from some fault reporting schemes which record information only when customers are interrupted and not for equipment or component failures when customer outages do not occur.

D. Evaluation Techniques

Reliability assessment of distribution systems has received considerable attention and there are a large number of publications dealing with the theoretical developments and applications [1]–[7]. The usual method for evaluating the reliability indexes is an analytical approach [22] based on a failure modes assessment and the use of equations for series and parallel networks [26]. A simulation approach is sometimes used for special purposes in order to determine, for instance, the probability distributions of the reliability indexes [16], [31]. The assessment procedure is to evaluate the reliability indexes at each individual load point by identifying the events leading to failure of the load point and using appropriate equations to evaluate the indexes.

Radial networks, or meshed ones operated radially, are the simplest to assess. In these cases the components are all in series and the equations needed to evaluate the basic indexes are very simplistic as follows:

$$\begin{aligned}\lambda_s &= \Sigma\, \lambda_i \\ U_s &= \Sigma\, \lambda_i r_i \\ r_s &= U_s/\lambda_s \\ E_s &= L \cdot U_s\end{aligned}$$

where

- λ_i component failure rate;
- r_i component restoration time;
- L average load at the load point.

The process is more complex for parallel or meshed systems. In this case the failure modes of the load point involve overlapping outages, i.e., two or more components must be on outage at the same time (an overlapping outage) in order to interrupt the load point. Assuming that failures are independent and that restoration involves repair or replacement, the equations used to evaluate the indexes of the overlapping outage are of the form

$$\begin{aligned}\lambda_p &= \lambda_i \lambda_j (r_i + r_j) \\ r_p &= r_i r_j/(r_i + r_j).\end{aligned}$$

The indexes λ_p and r_p then replace λ_i and r_i in the equations for series components to give the overall load point indexes. This approach only requires an understanding of the way in which each load point can fail and the relevant reliability data of the components leading to that failure. The system indexes, SAIFI, SAIDI (or SECURITY and AVAILABILITY in the U.K.), etc., can then be evaluated using the previously described principles.

This basic approach relates to a process involving a single failure mode, a single repair or replacement procedure, and independent failures. Although this is generally sufficient for radial networks, extensions are needed for more complex structures or additional component failure/restoration processes. More details regarding these techniques are available elsewhere [22]. The additional effects and factors include: adverse weather effects, common mode failures, types of outage (such as permanent, temporary, transient, scheduled), partial loss of continuity, effect of transferable loads, and embedded generation. Most of these can be included in the assessment procedure using adaptations of the previous equations for overlapping outages.

E. Examples of Reliability Assessments

It is not possible within the short space of this paper to describe detailed sets of analyses. For this information the reader is referred to [22] or one of the many application papers [1]–[7]. Instead, a few results extracted from [22] are used to illustrate some of the concepts described above.

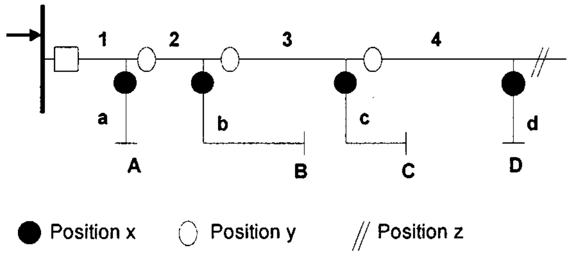

Fig. 16. Small radial distribution system.

Table 7
Results for Radial System

case	SAIFI	SAIDI	CAIDI	ASAI	AENS
base	2.20	6.00	2.3	0.999315	28.0
+ fuses at "x"	1.15	3.91	3.39	0.999554	18.3
+ isolators at "y"	1.15	2.58	2.23	0.999706	11.7
+ backfeed at "z"	1.15	1.80	1.56	0.999795	8.4

SAIFI - interruptions/customer.yr ≡ Security
SAIDI - hr/customer.yr ≡ Availability
CAIDI - hr/customer interruption
AENS - kWh/customer.yr

1) *Radial Systems*—Consider the system shown in Fig. 16. The basic function can be achieved by solid teed-points and no isolators/disconnects. This arrangement is perfectly adequate if no failures occur. This however is not realistic and protection devices and isolators are usually installed in order to improve system reliability. Consider the possibility of installing fuses at points "x," isolators at points "y," and a backfeed at point "z." This produces the results [22] shown in Table 7. Each reinforcement produces a further improvement in the reliability indexes. The question is "Is the improvement worth it?" which, from customers' perspectives, can be judged by evaluation of outage costs, which will be discussed later.

2) *Meshed Systems*—The effect of considering some of the various factors discussed previously on the reliability behavior of a two-branch parallel system can be illustrated by the following results [22]. The effect of weather is shown in Fig. 17. This curve indicates the ratio between the actual failure rate if an increasing number of failures occur in adverse weather and that when all failures occur in normal weather. This ratio represents the error factor if the true effect of weather is neglected. The effect of considering different outage modes, permanent, temporary, and scheduled maintenance, is illustrated in Table 8. This indicates that, not only can the indexes for each failure event and the overall load point be evaluated, but also the contribution of each outage mode can be highlighted using this structural procedure. The effect of failure criterion is illustrated in Table 9. The overall indexes and those for total loss of continuity (TLOC) and partial loss of continuity (PLOC) are shown. These results indicate that, if only TLOC is considered, there seems to be little to choose between the load points, but if PLOC is also included, the unreliability of load point 3 seems "worse." The conclusion as to which is "best" or "worse" depends on the requirements of the customers, their expectations and assessment of worth of supply.

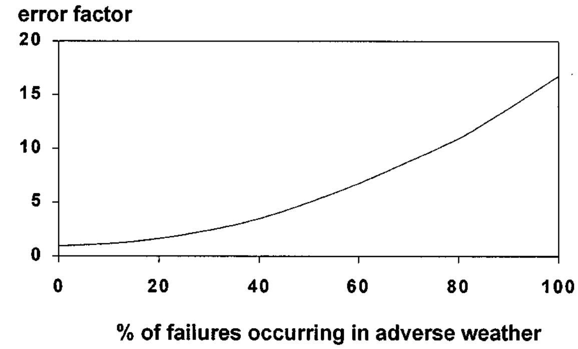

Fig. 17. Effect of weather.

Table 8
Effect of Outage Modes

overlapping outage	λ, f/yr	r, hr	U, hr/yr
permanent/permanent	6.99×10^{-4}	5.88	4.11×10^{-3}
permanent/maintenance	1.86×10^{-3}	4.50	8.39×10^{-3}
temporary/permanent	4.23×10^{-3}	0.32	1.37×10^{-3}
temporary/maintenance	1.10×10^{-2}	0.32	3.49×10^{-3}
total	1.78×10^{-2}	0.98	1.74×10^{-2}

Table 9
Effect of TLOC and PLOC

load point	criterion	λ, f/yr	r, hr	U, hr/yr	L, MW	E, MWh/yr
2	TLOC	0.02	5	0.10	15	1.5
	PLOC	3.61×10^{-6}	4.9	1.77×10^{-5}	4.6	8.16×10^{-5}
	total	0.02	5	0.10	15	1.5
3	TLOC	0.02	5	0.10	7.5	0.75
	PLOC	0.07	9.6	0.68	3.3	2.24
	total	0.09	8.6	0.78	3.8	2.99

F. Distribution Systems with Embedded Generation

1) Concepts of Embedded Generation: The installation of relatively small-scale generation within a distribution network imposes additional modeling requirements. In fact, the distribution network, historically mainly a supplier of energy received from bulk supply points, is becoming a mini-composite system having characteristics previously associated only with HLII. Particular modeling problems relate to the weak nature of the network in which they are embedded, and the fact that they exist much closer to actual consumers than large-scale global generation. Furthermore, they can frequently become disconnected from BSP but still be connected to consumers. This leads to the question whether they can be allowed to continue supplying load (preferable from a reliability point of view) or whether they must be tripped (preferable from a safety point of view).

Embedded generation in theory could be sourced from many forms of primary energy. The current types include wind, solar, CHP (combined heat and power), small-scale hydro, biomass, land-fill gas, etc. However, from a reliability modeling viewpoint, they can generally be grouped into two main types; those which have an output dependent on a variable energy source (e.g., wind, solar) and cannot be prescheduled, and those that are not so dependent (e.g., hydro, gas, diesel) and can be prescheduled. The latter type can be modeled using conventional generation approaches [22] since their contribution to the system supply is only dependent on need and the availability of the units themselves. The former, however, are much more difficult to deal with because their contribution depends on the source of energy being available (if this energy source is quiescent then all units in the same geographical area are likely to be equally affected) as well as need and unit availability.

2) Previous Reliability Assessment Approaches: Initial studies of the reliability impact of unconventional energy sources (generally renewables) have dealt with the problem only at the generation level (HLI) and have mainly centered on large-scale hydro, small-scale run-of-river hydro, and wind energy conversion systems. The first attempts to include unconventional energy sources used the loss-of-load approach. A method which included frequency and duration concepts is presented in [39]–[41] for wind energy conversion systems. Another approach using the cumulant method is illustrated in [42]. Correlation between load and the power output of unconventional units is taken into account in [43]. Methods based on the load modification technique were developed in [44] and [45] with economic assessment included in [44]. None of these previous approaches consider explicit modeling of all the factors affecting the source of generation, e.g., wind farm, and instead treat the overall plant or farm as a single entity. The effect of the individual components and factors are therefore masked and the impact of being embedded in a weak network is generally neglected. However, some recent publications have included these additional factors [46]–[52].

3) Modeling and Evaluation Approach: As discussed before, energy sources can be classified into one of two types. The most difficult to deal with are those having an output dependent on unpredictable external energy sources such as wind and sun. Although the following is discussed in terms of wind generation systems, the approach is equally applicable to other intermittent energy sources such as solar. The principle is to develop models that can take into account the stochastic nature of wind (and other sources), the failure and repair processes of the wind turbines, their output curves, wind speed spatial correlation, and wake effects using reliability analysis based on analytical techniques. This model can then be integrated with available models of the distribution network and can also be used for generation level (HLI) studies allowing and including a full reliability assessment of the system. Full details of these techniques are described in [46]–[48].

The approach focuses on the wind farm perspective looking from inside the wind farm into the network. The results are integrated into reliability assessment techniques. Therefore, appropriate reliability results are evaluated at the wind farm boundary and also at any network/system boundary beyond. These results form the primary set of indexes needed by all the parties involved (generators, network owners and operators, energy suppliers, end-customers) in order to identify the effect of wind generation on their activities.

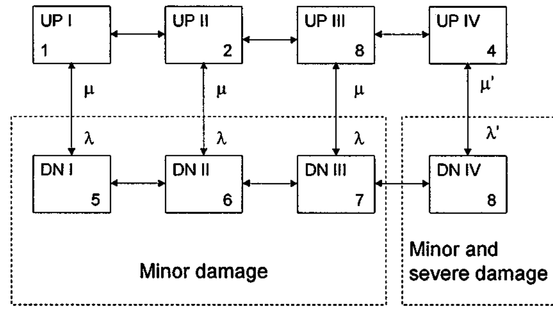

Fig. 18. Reliability model for wind turbine.

The total output of the wind farm is obtained by appropriately aggregating the outputs of each individual generator. The conventional approach to aggregate these outputs using probabilistic analytical techniques is the convolution of their individual capacity outage probability tables [22]. This approach is applicable to nonintermittent sources such as gas, diesel, and even CHP, but is not valid for wind generators or solar plant. The problem is that the outputs of units such as wind turbines are dependent on a common source, i.e., the wind. Therefore, there is statistical dependence between the different generation output states, whereas independence is an underlying assumption in the convolution of capacity outage probability tables. Consequently, it is not possible to calculate a generation output capacity table by convolving the output table of each wind turbine. The wind farm has to be considered in its entirety.

Determination of the statistical output characteristics of a wind farm for reliability analysis requires the simultaneous consideration of all wind turbines. Therefore, a new wind farm generation model is needed which represents the stochastic characteristics of all processes involved. This can be accomplished by merging a wind (energy source) model and a wind turbine (generation) model [46]–[48]. The basic principle is to derive a Markov model for the wind by discretizing the continuous wind speed records and combining this with models that represent the failure and repair processes of the wind generators. Each state can be associated with a generation output level depending on the relationship between wind speed and turbine output.

Several models have been considered for the wind turbines [46]–[48], some with extensive complex configurations. However, the model shown in Fig. 18 proved to be the best compromise between accuracy and computational effort. This model has the following characteristics.

1) Four wind speeds are included; I (states 1 and 5), II (states 2 and 6), III (states 3 and 7) and IV (states 4 and 8).

2) The wind turbine can be available (e.g., state 1 represents the up or available state during wind state I) or unavailable due to failure (e.g., state 5 represents the down or unavailable state during wind speed I).
3) λ and μ represent the failure rate and repair rate of the turbine.
4) The failure rates and repair rates are the same during wind speeds I, II, and III and failures of the turbine are associated with minor damage only.
5) Wind speed IV (associated with states 4 and 8) is a very severe condition during which the failure rate increases (significantly) to λ' and the repair rate μ' may also change. Failures may result in minor or severe damage.
6) While in a state, the transitions are associated with failure or repair as appropriate, and with a change in wind speed.

This model does not truly reflect correct behavior with respect to state 8. A transition from state 7 implies that a minor damage condition in state 7 could become a severe damage condition in state 8 and vice versa. Clearly this is not reasonable and severe damage can only occur following a transition from state 4. However, extensive assessments showed [47] this model tends to give slightly more pessimistic results due to the prevailing effect of transitions from minor damage states to severe damage states over the opposite direction transitions. This model can be solved using conventional Markov analysis [26], the outcome of which provides an equivalent capacity outage probability table that takes into account all the stochastic variable and dependencies. This not only represents the behavior of the wind farm (important to the generator and energy supplier) but also provides the input to an overall reliability assessment of the distribution system.

The conventional approach [22] to evaluate distribution system reliability is a load point orientated one based on minimal cut set theory, i.e., a load point is selected, relevant outages for that load point identified, and load point indexes evaluated. Instead of using the load-point driven approach, a method similar to that used for assessing transmission systems can be used [47], [48], [52]. This is an event-driven approach, which proves more appropriate for distribution systems containing embedded generation. Instead of selecting a load point and studying all events that could lead to interruption of supply at that load point, a contingency event is considered and all the load points that are affected by it are deduced simultaneously.

In this approach, each contingency is a particular system state which, when embedded generation exists in a distribution system, is made up from a wind generation state, a load state and a network state. The generation states are given by the output of the wind farm model described above or obtained from conventional convolution for nonintermittent sources. The load states can be deduced from load levels sequentially predicted for the system being analyzed or from any other suitable model. The network model defines state events and failure modes similar to those used in conventional reliability models of distribution systems. A full description is given in [47], [48], [52].

4) Reliability and Production Indexes: In order to express the results of the reliability and production analysis, an adequate set of indexes is required. With careful interpretation these can be used to quantitatively compare different systems and to measure the benefit of alternative designs, strategies, and impact of embedded generation.

1) *Capacity Credit*—One measure that has become associated with embedded generation is the term "capacity credit." This is said to be the effective capacity for which the generation source can be credited and is evaluated by dividing the energy generated in a period by the number of hours in that period. It therefore gives the average capacity that the system sees measured over the period considered. Although this may seem to provide a useful measure, it is only useful to a generator as an indicator of overall contribution but is flawed as a useful reliability index for either customers or energy suppliers, particularly in connection with intermittent sources such as wind. In order to illustrate one weakness, let us consider a capacity credit of 25%, for example, which may be considered typical for a wind farm. This means that, on average, it supplies 25% of the installed capacity continuously. In reality, it can supply (in simple terms) either full capacity (four times its capacity credit) for 25% of the time, or nothing for 75% of the time. This may be much less of a problem for sources not dependent on the environment and which can be scheduled and controlled, in which case the value of capacity credit becomes very large.

   It can also be concluded that, because of their intermittent nature, such sources cannot replace conventional generation and are really energy-replacement rather than capacity-replacement sources [44]. As wind power plants with higher installed capacities are incorporated into existing power systems, the problem becomes even more emphasized and it becomes increasingly important to study the reliability of these generation systems and assess the effects that they will have on the entire system and its reliability. In order to achieve this, additional and more meaningful indexes and measures are therefore required.
2) *Reliability Indexes*—There are many reliability indexes that can be calculated. The most appropriate depends on the perspective viewed by each party involved. Energy-based indexes may be the most appropriate from a generator's perspective because these permit assessment of income derived, but interruption-based indexes may be more appropriate from an end-customer's perspective because these determine their ability or inability of using the supply. It is therefore important to be able to evaluate a range of indexes and choose the most relevant depending on the circumstances and objective of any particular decision process. These include all the previous load point and system indexes.
3) *Production Indexes*—The generation indexes used in HLI studies could be used unchanged for embedded generation. However, because these units are close to

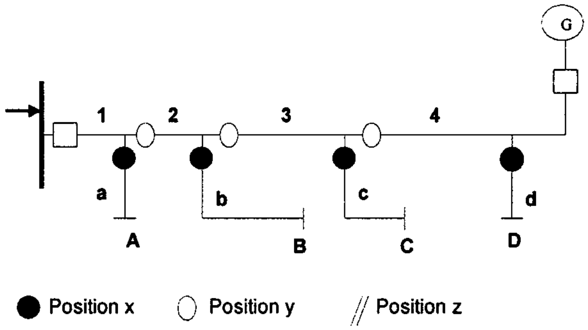

Fig. 19. Radial system with wind farm.

actual end-customers a different set are generally more applicable in order to reflect the specific aspects affecting the performance of embedded generation. In the case of wind [46]–[48], [52], these include the following.

1) Installed wind power (IWP). Sum of the rated power of all the wind generators in the wind farm.
2) Installed wind energy (IWE). Installed wind power multiplied by a year, this is the energy that could be extracted if the units could be operated continuously (IWP × 8760).
3) Expected available wind energy (EAWE). Expected amount of energy that would be generated in a year, if there were no wind turbine generator (WTG) outages.
4) Expected generated wind energy (EGWE). Expected maximum amount of energy that would be generated in a year by the real WTG's considering their outage rates and the real wind to which they are exposed.
5) Expected wind energy utilized (EWEU). Expected amount of wind energy that can be utilized by the load, which is less than EGWE due to failures in the distribution network.
6) Expected exported wind energy (EEWE). Expected amount of energy available for export across the system boundary.
7) Wind generation availability factor WGAF: EGWE/IWE.
8) Wind generation utilization factor WGUF: EWEU/EGWE.
9) Capacity factor (≡capacity credit): WGAF × WGUF.

G. Study Cases

1) Simplified Case Studies: In order to illustrate the principles associated with the reliability assessment of distribution systems containing embedded generation, the system shown in Fig. 16 is modified to include an embedded generation plant sited at the end of Feeder Section 4, as shown in Fig. 19. Two main cases are considered. The first one is when the embedded generation cannot be operated independently of the main BSP. The second one is when the embedded generation can be run independently.

1) *Embedded Generation Cannot be Run Independently of the BSP*—This situation may arise due to a failure of the BSP, of the transmission system leading to the BSP, or of the distribution feeder between the BSP and the load center. The results are shown in Table 10.

The indexes shown in Table 10 would be exactly the same as those without embedded generation since, whenever a failure occurs, the embedded generating plant is also disconnected. The one distinctive difference is that the energy delivered by the BSP will be reduced from 65.7 G Wh (without embedded generation) to 39.4 G Wh (with embedded generation), the difference being the energy delivered by the embedded generation plant. This confirms that one contribution of embedded generation is energy replacement. It could also contribute to a reduction of system losses but this is not indicated in this example because it considers continuity only and therefore neglects power flows and the resulting effects.

This is an oversimplified example because it assumes the embedded generation is always available and it neglects two situations for which embedded generation can contribute to increased reliability. First, if an outage occurs in a meshed system, the generation may be able to support some load which may have had to be disconnected due to network violations (partial loss of continuity, PLOC [22]). Second, following year-on-year load growth, network capacity may be reached requiring reinforcement of the network. An alternative to expanding the network is to make use of local generation.

2) *Embedded Generation Can be Run Independently of the BSP*—In this situation, the source can continue to supply all or some of the load when supply from the BSP is lost. Two sets of results are included. The embedded generation has a capacity of 3000 kW and is:

1) always available;
2) only available for 25% of the time.

The results for these case studies are shown in Tables 11 and 12.

It can be observed in all cases that the failure rate, and therefore SAIFI/Security remains unchanged because, when a fault occurs, the protection breakers at both the BSP and the embedded generating plant must be tripped. This is followed by opening appropriate disconnects and restarting the generator. An improvement in the failure rates and SAIFI/Security could be achieved by using protection breakers in place of some or all the disconnects. However, there is a significant reduction in the outage times, the annual unavailabilities and the overall SAIDI/Availability. This is due to some loads being supplied by the embedded generator following switching while the main supply is being restored. This benefit is greatest when the generator is always available and least when the generator is available for only 25% of the time. The first situation reflects usage of, say, diesel generators and the second

Table 10
Reliability Indexes with Embedded Generation (Tripped When Supply is Interrupted)

failure	Load point A			Load point B			Load point C			Load point D		
	λ	r	U	λ	r	U	λ	r	U	λ	r	U
section												
1	0.2	4	0.8	0.2	4	0.8	0.2	4	0.8	0.2	4	0.8
2	0.1	0.5	0.05	0.1	4	0.4	0.1	4	0.4	0.1	4	0.4
3	0.3	0.5	0.15	0.3	0.5	0.15	0.3	4	1.2	0.3	4	1.2
4	0.2	0.5	0.1	0.2	0.5	0.1	0.2	0.5	0.1	0.2	4	0.8
lateral												
a	0.2	2	0.4	-	-	-	-	-	-	-	-	-
b	-	-	-	0.6	2	1.2	-	-	-	-	-	-
c	-	-	-	-	-	-	0.4	2	0.8	-	-	-
d	-	-	-	-	-	-	-	-	-	0.2	2	0.4
Total	1.0	1.5	1.5	1.4	1.89	2.65	1.2	2.75	3.3	1.0	3.6	3.6

Security = 115 interruptions/100 customers
Availability = 155 minutes/yr
Average duration = 2.25 h/interruption
Expected energy not supplied = 19400 kWh or 3.23 kWh/customer
Energy delivered by BSP = 39.4 GWh
Energy delivered by embedded generation = 26.3 GWh, i.e. import reduction

Table 11
Reliability Indexes with Embedded Generation (Available Continously, Can Run Independently)

failure	Load point A			Load point B			Load point C			Load point D		
	λ	r	U	λ	r	U	λ	r	U	λ	r	U
section												
1	0.2	4	0.8	0.2	4	0.8	0.2	0.5	0.1	0.2	0.5	0.1
2	0.1	0.5	0.05	0.1	4	0.4	0.1	0.5	0.05	0.1	0.5	0.05
3	0.3	0.5	0.15	0.3	0.5	0.15	0.3	4	1.2	0.3	0.5	0.15
4	0.2	0.5	0.1	0.2	0.5	0.1	0.2	0.5	0.1	0.2	4	0.8
lateral												
a	0.2	2	0.4	-	-	-	-	-	-	-	-	-
b	-	-	-	0.6	2	1.2	-	-	-	-	-	-
c	-	-	-	-	-	-	0.4	2	0.8	-	-	-
d	-	-	-	-	-	-	-	-	-	0.2	2	0.4
Total	1.0	1.5	1.5	1.4	1.89	2.65	1.2	1.88	2.25	1.0	1.5	1.5

Security = 115 interruptions/100 customers
Availability = 117.4 minutes/yr
Average duration = 1.70 h/interruption
Expected energy not supplied = 14675 kWh or 2.45 kWh/customer

situation reflects usage of wind or solar, if it was permitted to use these independently of the main supply.

2) Meshed System Study: In order to demonstrate the application to a more extensive system, a study extracted from [47], [48], and [52] is described in here. The network used is shown in Fig. 20. It is a 33/11 kV meshed system connected to the 132 kV network by two parallel transformers. The total load is 82.55 MW. A wind farm made up of 15 × 1 MW machines is connected to bus 9. Typical wind, wind turbine, load profile and reliability data was used. The reliability indexes for the load buses, including interruption and energy indexes are shown in Table 13. The following observations can be made. The load point reliability indexes for the split busbars 2 and 5 are the same. However, the indexes for the split busbar 3 are different because of different reliability characteristics.

The system indexes are shown in Table 14 and the wind generation indexes in Table 15. The EEWE is calculated at the system boundary with the next voltage level (Bus 1). In

Table 12
Reliability Indexes with Embedded Generation (Available for 25% of Time, Can Run Independently)

wind farm status	Load point A			Load point B			Load point C			Load point D		
	λ	r	U	λ	r	U	λ	r	U	λ	r	U
Avail	1.0	1.5	1.5	1.4	1.89	2.65	1.2	1.88	2.25	1.0	1.5	1.5
Unav	1.0	1.5	1.5	1.4	1.89	2.65	1.2	2.75	3.3	1.0	3.6	3.6
Total	1.0	1.5	1.5	1.4	1.89	2.65	1.2	2.53	3.04	1.0	3.08	3.08

Security = 115 interruptions/100 customers
Availability = 145.8 minutes/yr
Average duration = 2.11 h/interruption
Expected energy not supplied = 18230 kWh or 3.04 kWh/customer

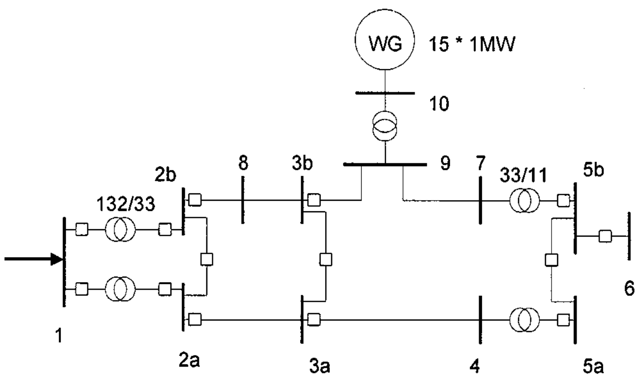

Fig. 20. Meshed system with wind farm.

Table 13
Load Point Indexes

Load point	Load MW	λ f/yr	U h/yr	r h	ENS MWh
2a	28.75	0.0000	0.0019	82.550	0.034
2b	28.75	0.0000	0.0019	82.550	0.034
3a	7.85	0.7585	12.726	16.802	59.98
3b	7.85	0.8400	14.096	16.808	66.44
5a	4.50	0.0110	0.1181	10.784	0.319
5b	4.50	0.0110	0.1181	10.784	0.319
6	0.35	0.6160	3.1420	5.1029	0.660

this case all the energy generated by the wind farm is consumed within the system being assessed. This is because the minimum load level in the network exceeds the maximum capacity of the wind farm: otherwise some energy would be available for export. The wind generation indexes show that the effect of failures in the interfacing network introduces restrictions to the wind farm output (WGUF = 0.9968). The effect however is quite small.

The energy statistics for this system are shown in Table 16. The main effect of introducing the wind farm is a reduction in energy losses in the system of about 21%. Thus, the immediate effect is an instant increase in the efficiency of the system operation. Moreover, in this case the net imported energy from the 132 kV system was reduced from 101% of the

Table 14
System Reliability Indexes

Index	Value
SAIFI	0.156 int/customer.yr
SAIDI	2.58 h/customer.yr
CAIDI	16.54 h/customer int
ASAI	0.999706
ASUI	0.000294
ENS	127.8 MWh/yr
AENS	0.015 MWh/customer.yr

Table 15
Wind Generation Indexes

index	value	
IWP	15.0	MW
IWE	131,400	MWh/yr
EAWE	35,333	MWh/yr
EGWE	34,642	MWh/yr
EWEU	34,530	MWh/yr
EEWE	0	MWh/yr
Availability	0.98042	
WGAF	0.2636	
WGUF	0.9968	
WGAF x WGUF	0.2628	

Table 16
Energy Balances

Energy (MWh)	Without wind farm	With wind farm
Consumed	434,045	434,045
Net imported	438,278	402,873 (-8.08%)
Exported	0.0	0.0
Losses	4,232.4	3,357.5 (-20.68%)
Wind farm exported	0.0	34,530

Table 17
Summary of COC's for Radial System

case	expected COC, k$/yr				
	A	B	C	D	total
base	114.9	91.9	68.9	46.0	322
+ fuses	69.5	67.7	46.2	27.8	211
+ disconnects	28.6	40.5	38.1	27.8	135
+ backfeed	28.6	29.6	25.8	11.5	96

total energy consumed to 92.8%. Thus, a reduction in energy purchase from the 132 kV system of more than 8% can be expected.

These results show that the approach provides valuable information relating to the energy exporting capability of an embedded generating plant (information of benefit to the plant owner and operator), the energy consumed by the end customers (of benefit to the distribution company, energy suppliers and consumers), and the energy available for export to other systems and the grid (of benefit to distribution and grid companies). The results also show that the reliability indexes of customer load points do not change significantly when embedded generation is not permitted to operate as stand-alone units. However, one particular technical benefit is that there can be a significant reduction in system losses which is of direct benefit to the distribution company hosting the embedded generator. This, together with the energy-replacement feature of embedded generation, forms some of the most significant advantages of these sources of energy.

H. Application of Customer Outage Costs

1) *Radial Systems*—In order to illustrate the application of reliability worth assessments in distribution systems, reconsider the radial system shown in Fig. 16. Assuming a particular CCDF for the customers at the four load points gives the typical results [22] shown in Table 17. As expected, the COC's decrease as the subsequent modifications and investments in the system are made. The figures in each case should be considered in conjunction with the annual costs associated with making the modifications in order to decide on the optimum alternative.
2) *Asset Replacement*—To illustrate the calculation of COC's, the following example [17], based on part of an actual 33 kV network, considers some proposed changes in order to remove some obsolete switchgear. Fig. 21 shows the system before and after the proposed decommissioning of obsolete switchgear around busbars 1 and 2. The analysis is confined to buses 3 and 4 which are likely to be the most adversely affected by the proposed changes. For the sake of simplicity these buses are assumed to serve similar loads consisting of residential, commercial and industrial loads. In order to simulate the superior reliability of contemporary components and to allow for degraded performance due to age, the failure rate and repair times for switchgear in Fig. 21(b) are assumed to be two-thirds of those of the corresponding components in Fig. 21(a). Using typical data the resulting reliability indexes and COC's, SCOC's, and ΔCOC's are shown in Tables 18 and 19, respectively.

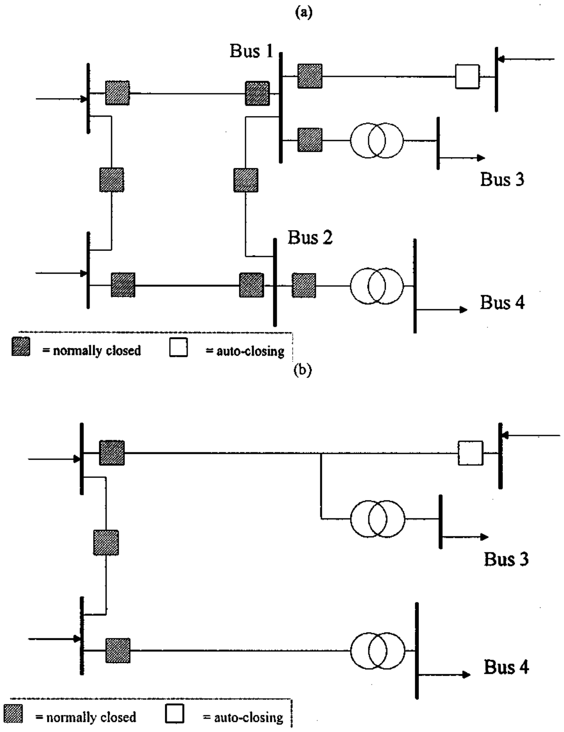

Fig. 21. Network to consider asset replacement, (a) before changes and (b) after changes.

Table 18
Results for Asset Replacement Systems

index	bus 3	bus 4
before proposed changes		
λ, f/yr	0.48	0.46
r, h	0.95	0.99
U, h/yr	0.46	0.46
after proposed changes		
λ, f/yr	0.70	0.53
r, h	3.69	4.68
U, h/yr	2.58	2.48

Table 19
Effect of Changes on COC's

costs (£)	before changes		after changes		ΔCOC (£)	
	bus3	bus4	bus3	bus4	bus3	bus4
COC	43,300	42,900	200,400	187,000	157,100	144,100
SCOC	86,200		387,400		301,200	

The results lead to the following comments. Although the failure rates do not seem to increase very much, the average outage durations change significantly, an effect captured by the ΔCOC's. In this example, the COC's increase significantly due to a weakening of the system. The ΔCOC's therefore represent the degradation cost seen by the customers and would have to be related to a likely significant reduction in investment compared with a like-for-like replacement.

I. Overall Comments

Many distribution systems are still designed according to deterministic standards. These views are changing quite significantly and there is now a positive awareness of the need to assess system design alternatives in a probabilistic sense. This awareness is increasing following the restructuring of the electricity supply industry since it is now necessary for planning and operation decisions to be transparent and equitable to all parties involved. This is particularly so in distribution systems in which many interested parties have conflicting interests, including the actual end customers, the network owners and operators, the energy suppliers, the owners and operators of the transmission network, the conventional generators, as well as new entrants concerned with embedded generation. The ability to objectively compare alternatives is becoming a necessity, and this can only be achieved quantitatively using probabilistic assessment approaches.

In addition, there is also a rapidly growing appreciation, inside and outside the industry, of the need to account for customers' expectations and their assessment of the worth of supply. Since the latter cannot be objectively assessed without quantitative reliability measures, the interrelation between the two aspects of reliability and worth of supply is also expected to become of significant importance in the very near future. This will lead to extended use of cost-benefit analyses.

VIII. Conclusion

This paper has reviewed existing reliability evaluation approaches and how these can be used and/or adapted to suit the competitive nature of modern power systems. In particular, it has addressed three very important new areas of development:

1) the related aspects of reliability and economics, which are inseparable because of the direct circular impact of investment cost on reliability, of reliability on customer outage costs, and of outage costs on the need to invest and therefore on investment cost;
2) the ability to bridge the gap between deterministic and probabilistic approaches to system planning and operation, rather than considering these as mutually exclusive alternatives;
3) the effect of generation that is becoming embedded in distribution systems, this generally being small-scale, intermittent (e.g., wind energy), and connected into weak parts of the network.

Although probabilistic approaches have been in existence for a considerable period of time, they have not always been used extensively. However, these methods will increase in importance in a competitive environment as deterministic security criteria are seen to be too conservative and uneconomic. Probabilistic cost/benefit analyses are therefore likely to become increasingly common and the techniques and approaches reviewed in this paper will become increasingly used in practice.

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