Chapter

Reliability Evaluation of Power Systems

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Abstract

Reliability evaluation of electric power systems is an essential and vital issue in the planning, designing, and operation of power systems. An electric power system consists of a set of components interconnected with each other in some purposeful and meaningful manner. The object of a reliability evaluation is to derive suitable measures, criteria, and indices of reliable and dependable performance based on component outage data and configuration. For evaluating generated reliability, the components of interest are the generating units and system configuration, which refer to the specific unit(s) operated to serve the present or future load. The indices used to measure the generated reliability are probabilistic estimates of the ability of a particular generation configuration to supply the load demand. These indices are better understood as an assessment of system-wide generation adequacy and not as absolute measures of system reliability. The indices are sensitive to basic factors like unit size and unit availability and are most useful when comparing the relative reliability of different generation configurations. The system is deemed to operate successfully if there is enough generation capacity (adequate reserve) to satisfy the peak load (maximum demand). Firstly, generation model and load model are convolved (mutually combined) to yield the risk of supply shortages in the system. Secondly, probabilistic estimates of shortage risk are used as indices of bulk power system reliability evaluation for the considered configuration.

Keywords: reliability, outage, availability, energy, power system, systems interconnection

1. Introduction

Reliability is one of the most important criteria, which must be taken into consideration during all phases of power system planning, design, and operation. A reliability criterion is required to establish target reliability levels and to consistently analyze and compare the future reliability levels with feasible alternative expansion plans. This need has resulted in the development of comprehensive reliability evaluation and modeling techniques [1–6]. As a measure of power system reliability evaluation in generation expansion planning and energy production, three fundamental indices are widely adopted and used.

The first reliability index is the loss of load expectation ($LOLE$) which denotes the expected average number of days per year during which the system is being on outages, i.e., load exceeds the available generating capacity.

The second index is the expected demand not supplied (ϵDNS) which measures the size of load that has been lost due to the severe outages occurrence.

The third index is the expected energy not supplied (ϵENS), which is defined as the expected size of energy not being supplied by the generating unit(s) residing in the system during the period considered due to capacity deficit or unexpected severe power outages [7, 8].

The implementations of these indices are now increasing since they are significant in physical and economic terms. Compared with generation reliability evaluation, there are also reliability indices related and pertinent to network (transmission and distribution) reliability evaluation.

There are two basic concepts usually considered in network reliability, namely, violation of quality and violation of continuity.

The first criterion considers violation of voltage limits and violation of line rating or carrying capacity, and the second criterion assumes that lines are of infinite capacity.

The transmission and distribution networks can be analyzed in a similar manner to that used in generation reliability evaluation, that is, the probability of not satisfying power continuity. This would give frequency and duration in network evaluation a simplification that is necessary. Provided the appropriate component reliability indices are known, it is relatively simple to calculate the expected failure rate (λ) of the system, the average duration of the outage (r), and the unavailability (U). To do this, the values of λ, r and U are required for each component of the system [9–11].

2. Types of system outages and deficits

A bulk generation model must consider the size of generation reserve and the severe outage(s) occurrences. An outage in a generating unit results in the unit being removed from service in order to be repaired or replaced. Such outages can compromise the ability of the system to supply the load and, hence, affect system reliability. An outage may or may not cause an interruption of service depending on the margins of generation provided. Outages also occur when the unit undergoes maintenance or other planned works necessary to keep it operating in good condition. The outages can be classified into two categories:

- A planned outage that results when a component is deliberately taken out of service, usually for purposes of preventive repair or planned maintenance
- A forced outage that results from sudden and emergency conditions, forcing the generating unit to be taken out of service

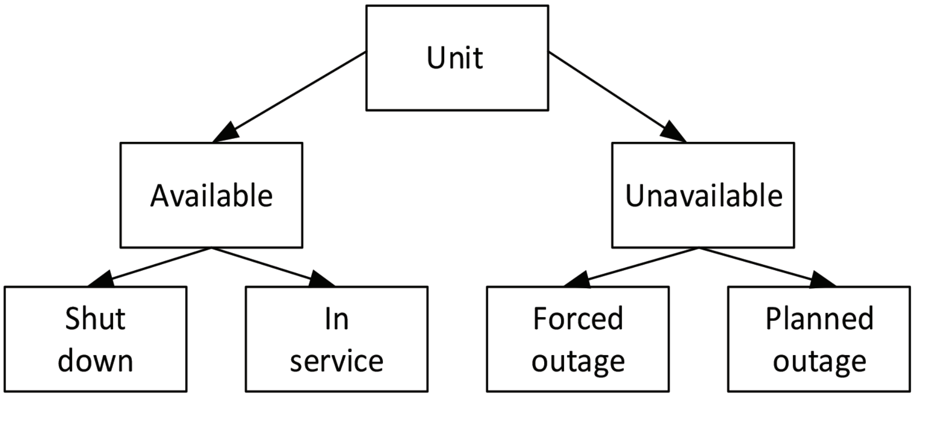


Figure 1.
Generating unit probable states.

The status of a generating unit is described as morphing into one of the several possible states, as shown in **Figure 1**.

To investigate the effect of a unit on system generation reliability, it is imperative to know its probability of residing in each state as in **Figure 1**. Hence, the following section introduces some basic probability concepts.

3. Introduction to power system reliability evaluation

3.1 Availability (AV) and forced outage rate (FOR)

Experience has shown that no machine is so reliable and dependable that it is available in successful operating condition all the time. That means that the machine needs to be off service (out of service) for maintenance or it may be off due to some other problems affecting its operation (see **Figure 1**). As such, an off-service status includes planned outages and forced outages. Planned outages (scheduled outages) are the ones when (a) unit(s) is purposely shutdown or taken out of service for maintenance or replacement. Forced outages are defined as the ones when (a) unit(s) is out of service due to failure (also called unscheduled or unplanned outage). The last one is the most severe and important factor in power system planning and operation and can be defined as

$$\text{Forced outage rate (FOR)} = \frac{\text{sum of time unit is being out of service}}{\text{Total time considered for unit service}} \tag{1}$$

$$\text{FOR} = \frac{t_1 + t_2 + t_3}{\text{Total time}} \tag{2}$$

Also, availability can be defined as

$$A\text{vailability (AV)} = \frac{\text{Time unit is being in service}}{\text{Total time considered for unit service}} \tag{3}$$

and $$\text{AV} + \text{FOR} = 1.$$

This can be seen in **Figure 2** as follows

The two terms "availability and forced outage rate" represent the probability of successful and failure event occurrence. According to the probability theory, it is known that the product $AV_1 \times AV_2$ represents the probability that both unit 1 and unit 2 are simultaneously in operation during a specified interval of time, and, also, $AV_1 \times AV_2 \times AV_3$ means 1 and 2 and 3 are in operation at the same time, and $FOR_1 \times FOR_2 \times FOR_3$ means that units 1, 2, and 3 are out of service in the same time.

Also, $AV_1 \times FOR_2$ means the probability that unit 1 is available (in service) and unit 2 is unavailable (out of service) in the same time.

For system generation reliability evaluation (including system expansion planning and/or systems interconnection), two models, namely, capacity model and load model, are needed; these are demonstrated and elaborated in the next two sections.

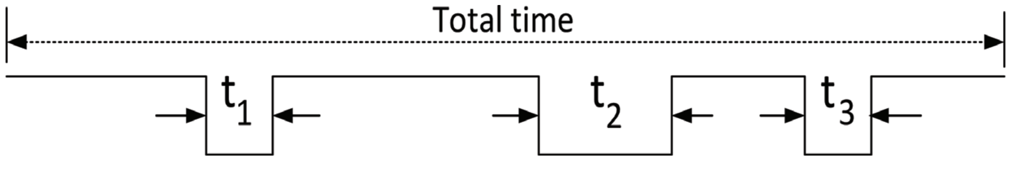


Figure 2.
Unit being available and unavailable.

3.2 Capacity model

The capacity model is known as the "Capacity Outage Probability Table (COPT)" that contains all capacity states (available and non-avoidable) in an ascending order of outage magnitude. Each outage (capacity state) is multiplied by its associated probability. If the system contains identical units, the binomial distribution can be used [12].

3.3 Load model

The load model is known as the "load duration curve (LDC)" which is the most favorable one to be used instead of the regular load variation curve. There are some facts about the LDC that should be realized and can be summarized as follows:

a. The LDC is an arrangement of all load levels in a descending order of magnitude.

b. The area under the LDC represents the energy demanded by the system (consumed).

c. LDC can be used in economic dispatching, reliability evaluation, and power system planning and operation.

d. It is more convenient to deal with than the regular timely load variation curve.

The above discussion for the load duration curve is depicted in **Figure 3** with all pertinent captions related to it.

3.4 Loss of load expectation (*LOLE*)

The *LOLE* risk index is the most widely accepted and utilized probabilistic method in power generation reliability evaluation for purposes of system expansion and interconnection. The two models, namely, the COPT and the LDC, mentioned

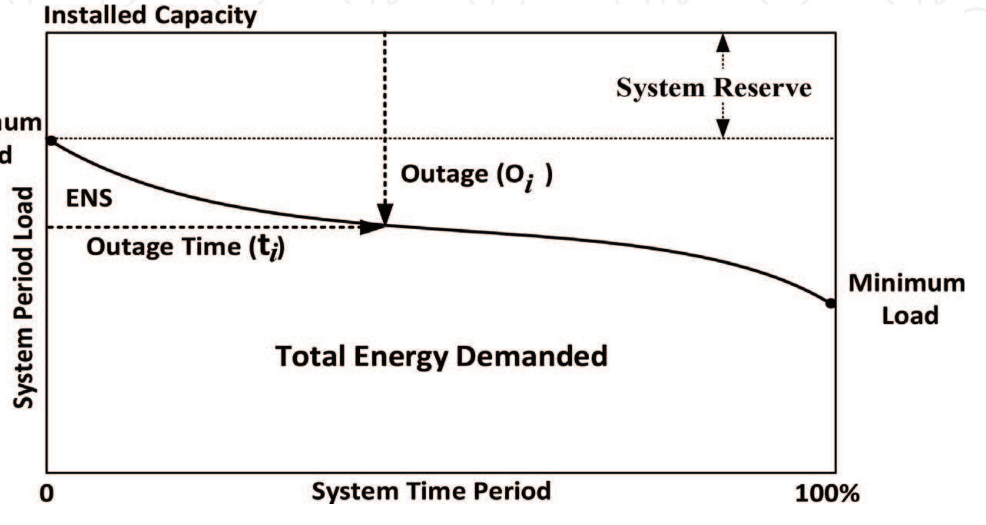


Figure 3.
System load duration curve, where O_i is the i^{th} outage(s) state in the COPT, t_i is the number of times unit(s) is unavailable, P_i is the probability of this i^{th} unavailable, and ENS is the energy not supplied due to severe outage (s) occurrence.

in the preceding sections are convolved (combined) in the process. The unit of the *LOLE* is in days per year (d/y). The *LOLE* evaluation method is expressed in the following mathematical formula:

$$LOLE = \sum_{i=1}^{n} t_i \cdot p_i(o_i)\ days/year\ [L_{max} > Reserve] \tag{4}$$

By observing the above equation, the *LOLE* would be applicable if, and only if, the maximum load (L_{max}) exceeds the system reserve. Consider now:

3.5 Expected demand not supplied (ϵDNS)

In power system planning another reliability index beside the *LOLE* may be required, so as to determine the size and magnitude of the load that has been lost due to severe outages (i.e., when $L_{max} > system\ reserve$), Hence, the ϵDNS can be obtained as follows:

$$\epsilon DNS = \sum_{i=1}^{n} (DNS_i) \cdot p_i\ MW/year \qquad [L_{max} > Reserve] \tag{5}$$

3.6 Expected energy not supplied (ϵENS)

Since power systems are in fact energy systems, the expected energy not supplied index may be deduced as per **Figure 4**. The ϵENS index is used in order to calculate energy sale, which is the real revenue for any electric company.

$$\epsilon ENS = \sum_{i=1}^{n} (ENS_i) \cdot p_i\ MWh/year\ [L_{max} > Reserve] \tag{6}$$

3.7 Energy index of reliability (EIR)

The ratio of expected energy not supplied (ϵENS) to the system's total energy demanded (***TED***) can be found as

$$\epsilon ENS_{pu} = \frac{\epsilon ENS}{TED} \tag{7}$$

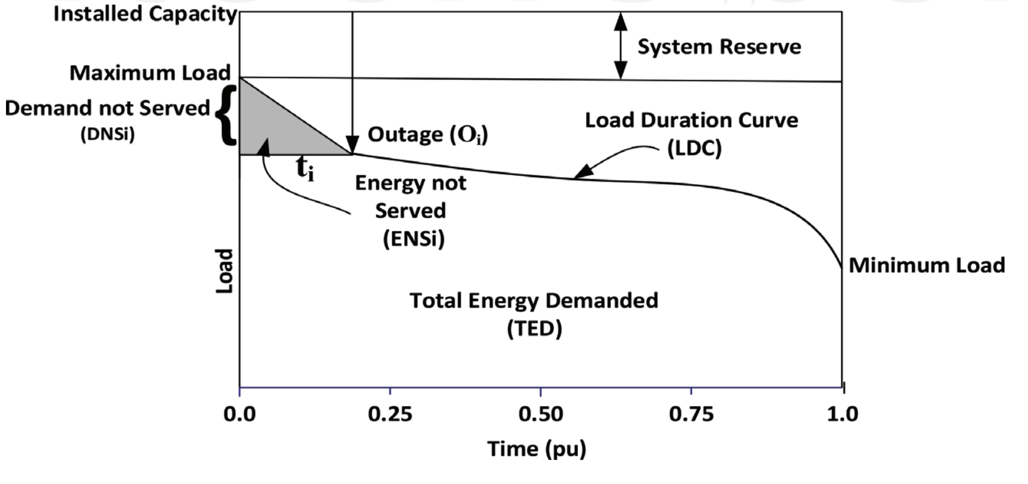


Figure 4.
Load duration curve with energy not served.

This ratio, in fact, is so small because of the small nature of the ϵENS and the large nature of the ***TED***, so, one can deduce another important reliability index called the ***EIR***, which can be expressed as follows

$$EIR = 1 - \epsilon ENS_{pu} \tag{8}$$

4. Energy production evaluation methodology

4.1 Basic concept

The expected energy supplied (ϵES) by the generating units (existing in the system) can be evaluated by using the concept of the expected energy not supplied (ϵENS) described previously. In this method, several factors are taken into consideration:

- Unit forced outage rate (FOR).
- Load duration curve (LDC).
- Capacity-Availability Table (CAT): a table that contains all the capacity states of the units in the system arranged according to their ascending order of availabilities.
- Loading priority levels: implies loading units in accordance to their least operating cost, i.e., operating, first, the most efficient and economical operating units (called the base units), then the more cost operating units (called the intermediate units), followed by the costliest operating units (called the peaker units), and so on. This means that the least cost operating units occupy the lower levels in the LDC, and the most expensive operating units occupy the upper levels in the LDC.

4.2 Method of evaluation of the expected energy supplied

The expected energy supplied (ϵES) by each unit available and being operated in the system can be evaluated by using the above concept of the expected energy not supplied (ϵENS), as shown below:

$$\epsilon ES_i = \epsilon ENS_{i-1} - \epsilon ENS_i \text{ MWh/year} \tag{9}$$

This method adopts a priority loading order, i.e., the generating units are loaded according to their least operating costs. The procedure applied is described above (see **Figure 5**).

The process of the above figure can be interpreted in the following steps:

- The load duration curve is implemented, as it is the type of curve that is widely used in power system reliability evaluation and planning for its convenience and flexibility. It is derived from the ordinary load curve and hence can be defined as "the arrangement of all load levels in a descending order of magnitude."
- The expected energy not supplied (ϵENS_0) before any unit is operated is the total area under the LDC.

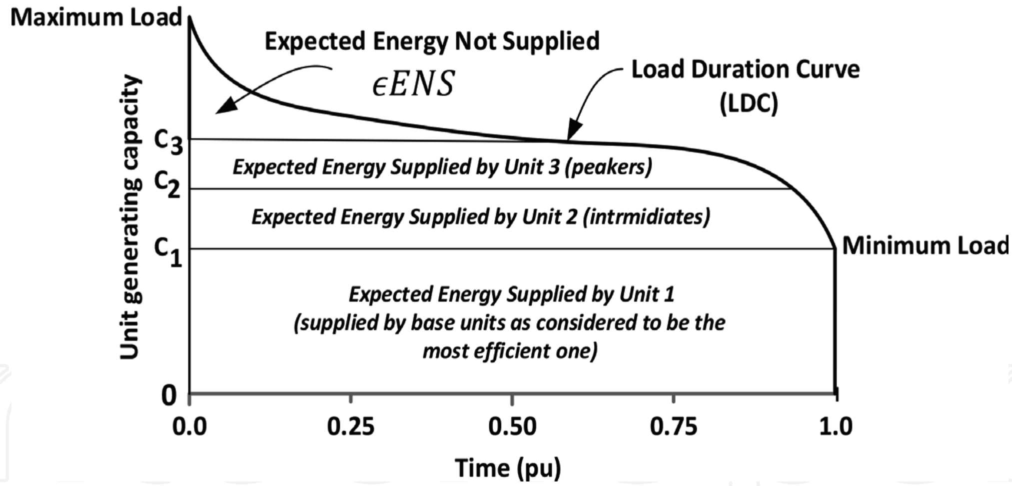


Figure 5.
Load duration curve displaying units loading priority.

- When the first unit (C_1) is loaded according to the priority loading level #1, it will occupy the area $(0 - C_1)$ and shifts the new expected energy not supplied (ϵENS_1) upward (i.e., above C_1). Therefore, the expected energy supplied by unit C_1 (ϵES_1) will be $\epsilon ES_1 = (\epsilon ENS_0) - \epsilon ENS_1$.

- When the second unit (C_2) is loaded according to the priority loading level #2, it will occupy the area $(C_1 - C_2)$ and then shift the new expected energy not supplied (ϵENS_2) upward above C_2. Therefore, the expected energy supplied by unit C_2 (ϵES_2) will be $\epsilon ES_2 = \epsilon ENS_1 - \epsilon ENS_2$.

- When the third unit (C_3) is operated according to the priority loading level #3, it will occupy the area $C_2 - C_3$ and then shift expected energy not supplied (ϵENS_3) above C_3, and then the process ends, and the remaining expected energy not supplied will be above C_3. As such, the expected energy supplied by unit C_3 (ϵES_3) will be $\epsilon ES_3 = \epsilon ENS_2 - \epsilon ENS_3$.

The following example shows an industrial compound case having two generating units, namely, 80 MW and 60 MW, which are assigned with a loading priority of "1" and "2," respectively. The expected energy supplied (ϵES) and the energy index of reliability (EIR) are both to be determined, so as to optimize its energy production with least possible operating cost.

Example: A power plant has the following data:

Capacity (MW)	FOR	Loading priority
80	0.06	1
60	0.03	2

The LDC is to be considered as a straight line connecting a maximum load of 160 MW and a minimum load of 80 MW (**Figure 6**). If the total operating time is 100 hours, evaluate the following:

a. The expected energy supplied $(\boldsymbol{\epsilon ES})$ by each unit in the system

b. The energy index of reliability $(\boldsymbol{EIR})$ of the system

The solution hereto is to, first, calculate the expected energy not supplied before any unit in the system is being loaded (ϵENS_0), i.e., at 0 MW, which is

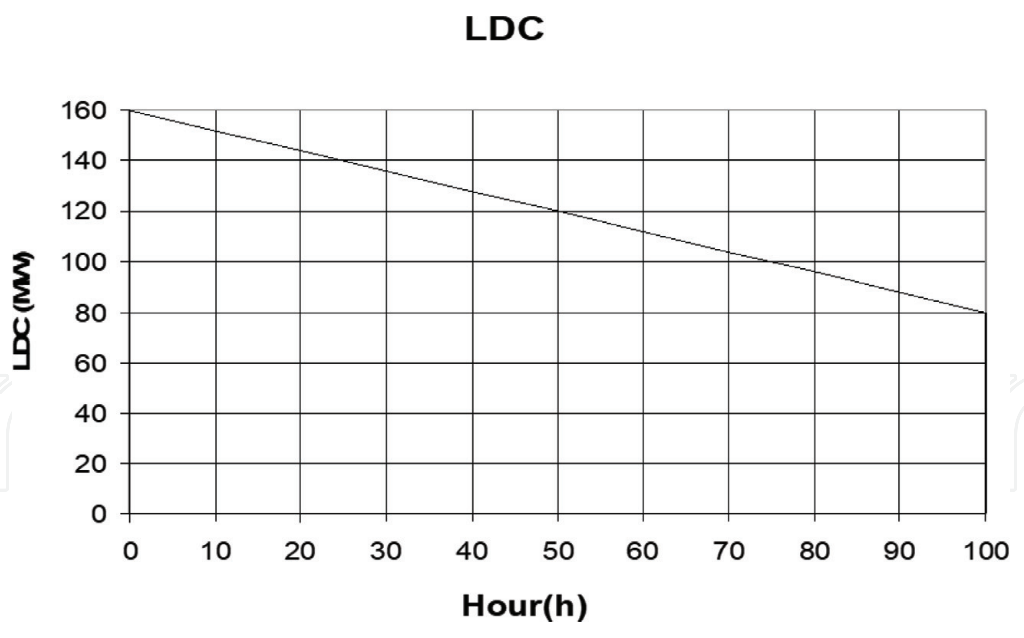


Figure 6.
Load duration curve for the given example.

$$\epsilon ENS_0[0\ \mathrm{W}] = 80 \cdot 100 + \tfrac{1}{2} \cdot 100 \cdot (160 - 80) = 12000\ \mathrm{MWh}\ \text{(Area under the LDC)}$$
$$\epsilon ENS_0[0\ \mathrm{W}] = 12000\ \cdot 1 = 12000\ \ \mathrm{MWh}$$

Now start loading the units starting with the first unit (i.e., 80 MW as unit no. 1 for the priority order no. 1). This is shown in **Table 1**.

$$\epsilon ENS_1[0\,\mathrm{MW}] = 12000\ \cdot 0.06 = 720\ \mathrm{MWh}$$

$$\epsilon ENS_1[80\,\mathrm{MW}] = \left[\frac{1}{2} \cdot 100 \cdot (160 - 80)\right](0 \cdot 94) = 3760\ \mathrm{MWh}$$

Therefore, the expected total energy not supplied after the first unit is being added ($\epsilon TENS_1$) will be

$$\epsilon TENS_1 = 720 + 3760 = 4480\ \ \mathrm{MWh}$$

Therefore, the expected energy supplied by the unit 80 MW (ϵES_1) can be evaluated as

$$\epsilon ES_1 = \epsilon \mathrm{MW}\, S_0 - \epsilon TENS_1 = 12000\ \text{-MWh}\ = \mathbf{7520}\ \ \mathrm{MWh}$$

Now, loading the second unit (i.e., unit of 60 MW as unit no. 2 for the priority order no. 2), the new CAT in **Table 2** will be

$$\epsilon ENS_2[0\ \mathrm{MW}] \quad = 1200 \times 0.0018 = 21.6 \quad \mathrm{MWh}$$

$$\epsilon ENS_2[60\,\mathrm{MW}] \quad = 6000 \times 0.0582 = 349.2\ \ \mathrm{MWh}$$

$$\epsilon ENS_2[80\,\mathrm{MW}] \quad = 4000 \times 0.0282 = 112.8\ \ \mathrm{MWh}$$

$$\epsilon ENS_2[140\,\mathrm{MW}] = 250 \times 0.9118 = 227.95\ \ \mathrm{MWh}$$

System capacity (MW)	Availability
0	0.06
80	0.94

Table 1.
System CAT at priority order level no. 1.

System capacity (MW)	Availability
0	0.06 × 0.03 = 0.0018
60	0.06 × 0.97 = 0.0582
80	0.94 × 0.03 = 0.0282
140	0.94 × 0.97 = 0.9118

Table 2.
System CAT at priority order level no. 2.

Therefore, the expected total energy not supplied after the second unit is being added ($\epsilon TENS_2$) will be

$$\epsilon TENS_2 = 21.6 + 349.2 + 112.8 + 227.95 = 711.55 \text{ MWh}$$

As such, the expected energy supplied by the unit 80 MW (ϵES_2) can be evaluated as

$$\epsilon ES_2 = \epsilon TENS_1 - \epsilon TENS_2 = 4480 - 711.55 = \mathbf{3608.45} \quad \text{MWh}$$

Hence, unit no. 1 (80 MW) will serve 7520 MWh, and unit no. 2 (60 MW) will serve 3608.45 MWh.

Now, the final remaining expected total energy not supplied ($\epsilon TENS$) MWh for this system is 711.55 MWh, and the system energy index of reliability (EIR) can be evaluated as

$$EIR = 1 - \frac{\epsilon TENS_2}{\epsilon TENS_0} = 1 - \frac{711.55}{12000} = 0.94$$

5. Applications of reliability indices in power system planning

Optimal reliability evaluation is an essential step in power system planning processes in order to ensure dependable and continuous energy flow at reasonable costs. Therefore, the reliability index, namely, the loss of load expectation ($LOLE$), discussed in Section 3.4 along with the other complementary indices discussed in Sections 3.5–3.7 can be quite useful. Indeed, in order to substantiate and verify the applicability thereof, these indices have been applied to a real power system case study situated in the northern part of the Kingdom of Saudi Arabia. This power system is supposed to serve a major populated community with a potential future commercial and industrial load growth acknowledging the Kingdom’s “Vision 2030.”

The various reliability and economic models incorporated in the planning process are portrayed in **Figure 7** and can be summarized as follows:

1. DATMOD: data model retrieving and organizing all studied system needed data like load duration curve (LDC), capacity outrage probability table

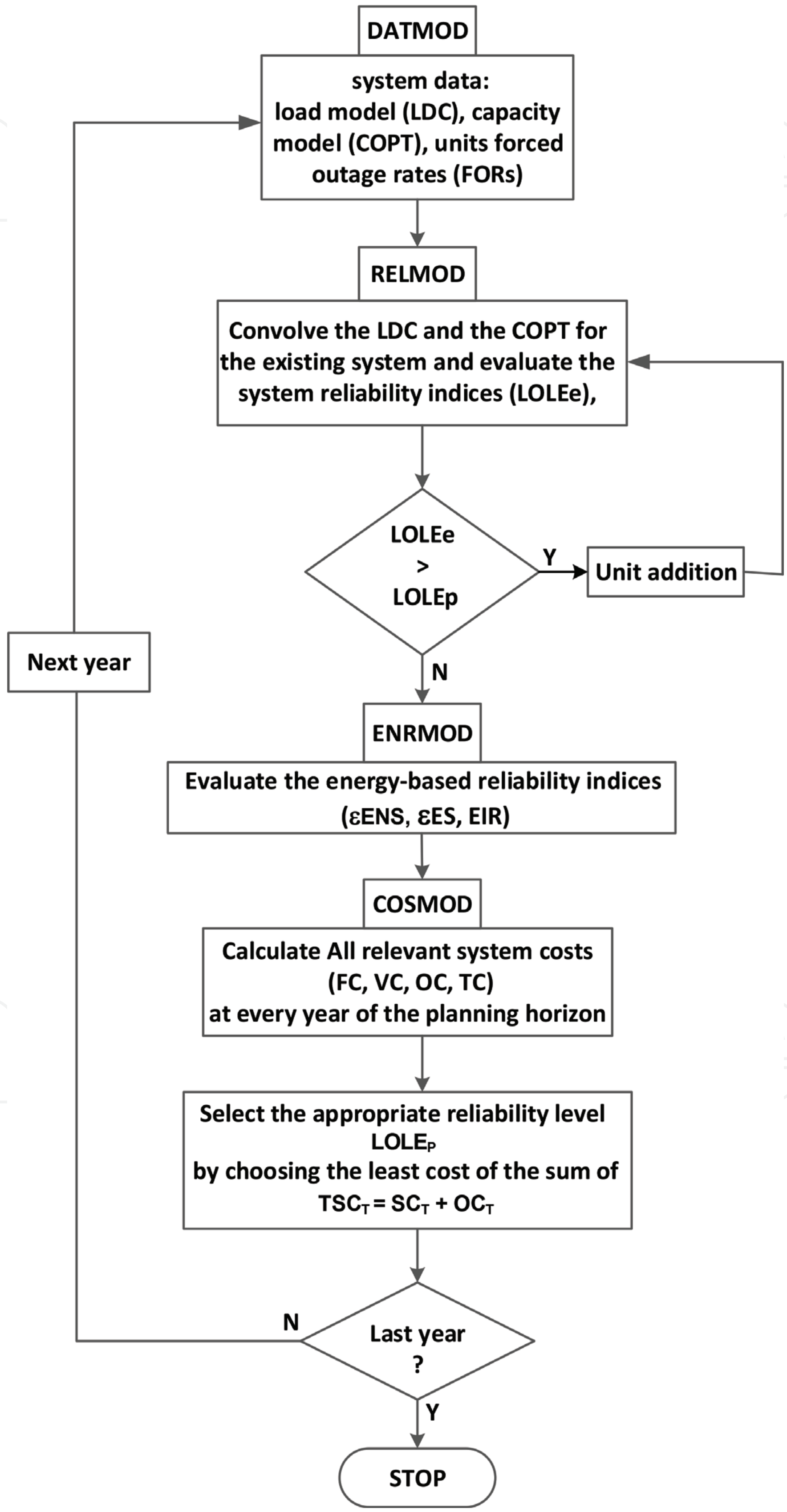


Figure 7.
Planning process for optimal reliability levels.

(COPT), and forced outage rates (FORs) pertinent to all generating units either residing in the system or newly added unit(s)

2. RELMOD: reliability model that evaluates studied system reliability ($LOLE$) levels at every year of the planning period and decides whether a unit(s) is needed to be added or to be postponed until it is required

3. ENRMOD: energy model which assesses expected energy supplied (ϵES) by the generating units residing in or added to the system and also estimates the remaining expected energy not supplied (ϵENS) and the energy reliability index (EIR)

4. COSMOD: cost model that estimates all cost pertinent to the system (system cost, outage cost, total cost) to be compared and assessed for optimum use

In order to obtain the most appropriate range of reliability levels, the system cost should be weighted with the estimated outage cost. System costs include fixed cost in terms of unit installation cost and variable cost in terms of fuel and maintenance cost. The outage cost (OC) forms a major part in the total system cost. These costs are associated with the demanded energy but cannot be supplied by the system due to severe outages occurrences, and is known as the expected energy not supplied, (ϵENS).

Outage cost is usually borne by the utility and its customers. The system outage cost includes loss of revenue, loss of goodwill, loss of future sales, and increased maintenance and repair expenditure. However, the utility losses are seen to be insignificant compared with the losses incurred by the customers when power interruptions and energy cease occur. The customers perceive power outages and energy shortages differently according to their categories. A residential consumer may suffer a great deal of anxiety and inconvenience if an outage occurs during a hot summer day or deprives him from domestic activities and causes food spoilage. For a commercial user, he/she may also suffer a great hardship and loss of being forced to close until power is restored. Also, an outage may cause a great damage to an industrial customer since it disrupts production and hinders deliveries.

The overall system cost depicts the overall cost endured by the customers as a value of uninterrupted power flow. The outcome of the process yields the results

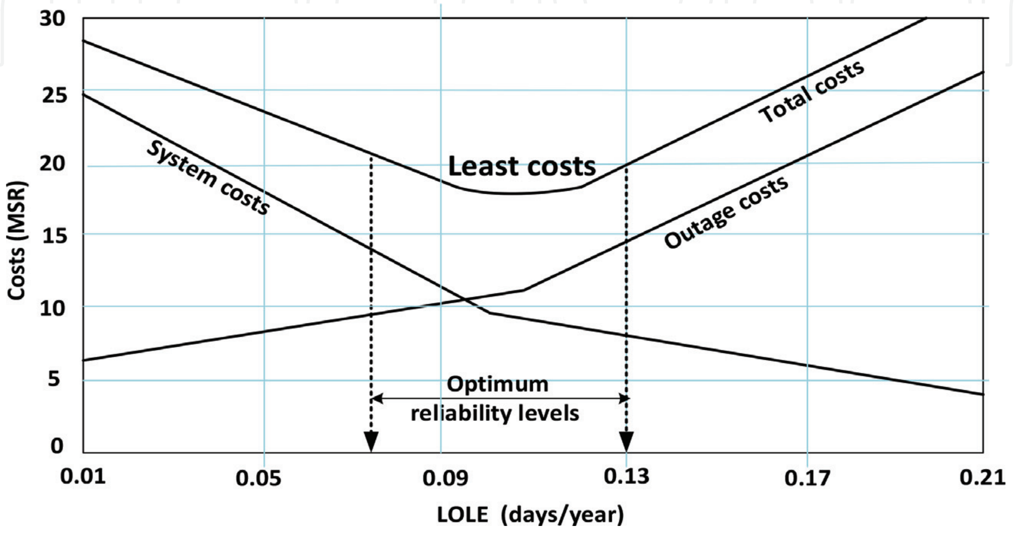


Figure 8.
Variations of LOLE levels with costs.

shown by **Figure 8**, in which system cost (*SC*) increases as the reliability level increases. At the same time, the outage cost (*OC*) decreases because of reliability improvement and adequate generating capacity additions. The most optimal reliability levels vary between 0.07 and 0.13 days/year (see **Figure 8**). However, in some cases adding new capacity may not signify the ideal solution to meet increasing future loads and maintain enhanced reliability levels. Therefore, it is better to improve an operating unit's performance through regular preventive maintenance. Likewise, establishing a good cooperation between the supply side (electric company) and the demand side (the customers) through well-coordinated load management strategies may further improve financial performance (1£ = 4.5 SR).

6. Applications of reliability indices in power system interconnection

6.1 Introduction

A review of the main advantages of electrical interconnection between electrical power systems is summarized as follows:

- When connecting isolated electrical systems, each system needs a lower generation reserve than the reserve when it is isolated and at a better level of reliability.

- When interconnecting isolated electrical systems, it is possible to share the available reserve so that each system maintains a lower level of reserve before being interconnected. This will result in both lower installation costs (fixed costs) and decreased operation costs (variable costs).

- The electrical connection reduces the fixed and operating costs of the total installed capacity.

- In emergency and forced outage conditions, such as breakdowns, multiple interruptions, and the simultaneous discharge of several generators, which may cause a capacity deficit that is incapable of coping with current loads and possibly a total breakdown of the electrical system as a whole, electrical interconnection helps to restore the state of stability and reliability of electrical systems.

- The interconnection of power systems enables the exchange of electrical energy in a more economical manner, as well as the exchange of temporal energy and the utilization of the temporal variation in energy demand.

- The electrical connection through the construction of larger power plants with higher economic return and reliability increases the degree of cooperation and the sharing of potential opportunities and possibilities that are available between the electrical systems.

- By nature, the various loads do not have peak values at the same time. As a result of this variation in peak loads (maximum demands), the load of the interconnected systems is less than the total load of each system separately, thus reducing and saving the total power reserve for systems.

6.2 Method of implementation

The above brief review of the main advantages and merits of electrical interconnection from an economic and technical point of view highlights the usefulness and importance of conducting electrical interconnection studies between the systems as they relate to the cost of capital and operational costs on the one hand and the improvement of their levels and performance on the other. Such studies are especially significant after the completion of the infrastructure of electrical systems. Indeed, the next step is to seriously consider linking electrical systems through unified national networks throughout the widespread Kingdom.

Most power systems have interconnections with neighboring systems. The interconnection reduces the amount of generating capacity required to be installed as compared with that which would be required without the interconnection. The amount of such reduction depends on the amount of assistance that a system can get, the transfer capability of the tie-line, and the availability of excess capacity reserve in the assisting systems.

One objective to be mentioned in this context is to evaluate the reliability benefits associated with the interconnection of electric power systems. Therefore, this study is focused on the reliability evaluation of two systems that may be viewed upon as both isolated systems and as interconnected systems. The analysis of this type explores the benefits that may accrue from interconnecting systems rather than being isolated as well as deciding viable generation expansion plans.

A 5-year expansion plan for systems A and B assuming a reliability criterion of 0.1 days/year (0.1–0.6 frequently quoted as appropriate values in most industrial countries) was determined. The analysis represents the expansion plans for both systems as being isolated and interconnected. An outcome of these expansion plans is shown in **Figure 9**.

If the two systems (A and B) are reinforced whenever the reliability index (risk level) falls below the prescribed level (i.e., $LOLE_p = 0.1\ \mathrm{d/y}$) at any year of the planning horizon, the results shown in the following table exhibits that the number

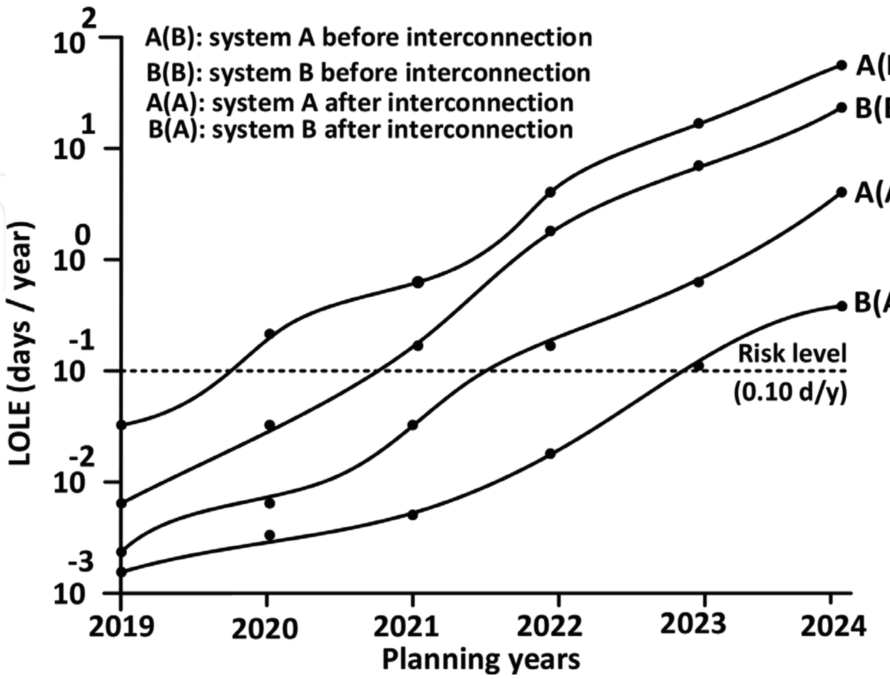


Figure 9.
LOLE levels before and after systems interconnection.

of added units and their cost are reduced if the two system are interconnected rather than being isolated.

System costs as isolated and interconnected:

System	Isolated			Interconnected		
	No. of unit	Cost (MSR)	ϵENS (MWh)	No. of unit	Cost (MSR)	ϵENS (MWh)
A	4	12.63	5.652	2	9.44	1.054
B	2	16.42	4.852	1	8.75	2.045

Therefore, it can be concluded from the above analysis that both systems will benefit from the interconnection. The reliability of both systems can be improved, and consequently the cost of service will be reduced through interconnection and reserve sharing. However, this is not the overall saving because the systems must be linked together in order to create an integrated system. The next stage must, therefore, assess the economic worth that may result from either interconnection or increasing generating capacity individually and independently.

7. Transmission and distribution reliability evaluation

7.1 Introduction

Since embarking on the national industrial development and the industrials program in the Kingdom of Saudi Arabia, the Ministry of Energy, Industry and Mineral Resources launched two solar PV projects with a combined generation capacity of 1.51 GW enough to power 226,500 households. These projects will be tendered by mid-2019 to attract a total investment of $1.51 billion Saudi Riyals creating over 4500 jobs during construction, operations, and maintenance [13]. The program will be phased and rolled out in a systematic and transparent way to ensure that the Kingdom benefits from the cost-competitive nature of renewable energy. The National Renewable Energy Program aims to substantially increase the share of renewable energy in the total energy mix, targeting the generation of 27.3 gigawatts (GW) of renewable energy by 2024 and 58.7 GW by 2030. This initiative sets out an organized and specific road map to diversify local energy sources, stimulate economic development, and provide sustainable economic stability to the Kingdom in light of the goals set for Vision 2030, which include establishing the renewable energy industry and supporting the advancement of this promising sector.

7.2 Role of the government in the electricity sector

As a result of the continuous subsidy and generous support of the government for the electricity sector, the ministry has been able to accomplish many electrical projects in both urban and rural areas, resulting in electric services that can reach remote areas and sparsely populated areas, over rough roads and rugged terrain. In fact, electric services require large sums of money to finance, build, operate, safeguard, and sustain. Another important component that must be considered along with the continuous operation and maintenance expenditures is fuel costs. Therefore, constant maintenance measures ought to be implemented to ensure the level and continuity of the flow of electrical energy without fluctuation, decline, or interruption.

The expansion of the electricity sector during the last three decades has resulted in the many electricity companies throughout the Kingdom being integrated into what was known, for a short time, as "the Saudi Consolidated Electric Companies (SCECOs)." These companies later merged into a single more reliable, efficient, and less expensive company known as the "Saudi Electricity Company (SEC)." Moreover, some areas (Eastern and Central) have been linked via a tie-line in order to prepare for the integration of the entire Kingdom under a unified national network.

Experts and planners of electrical power systems find it economically and technically unfeasible to increase the electrical capabilities of electric power plants that are often isolated, dispersed, and distant. However, after the completion of the structures of these systems, the next and natural step, to achieve advantages and benefits, is to connect these electric power systems to each other through unified transmission networks. Undoubtedly, linking these power systems will both reduce the cost of construction and provide reserve and fuel, all while increasing the strength of the electrical system and maximizing its capability to meet current and future electric loads.

7.3 Practical example

One practical example demonstrating the evolving of industry of electric sector in the Kingdom of Saudi Arabia will be shown in this section. The availability of network can be analyzed in a similar manner to that used in generating capacity evaluation (Section 3.1). Therefore, the probability of failing to satisfy the criterion of service adequacy and continuity can be evaluated. Provided the appropriate component reliability indices are known, it is relatively simple to evaluate the expected failure rate (λ) of the system, the average duration of the outage I, and the unavailability or annual outage time (U). To do this, the values of λ, r, and U are required for each component of the system.

7.3.1 State probabilities

The state-space transition diagram for a two-component system is shown in **Figure 10**.

The probability of a component being in the up state is $\frac{\mu}{\lambda+\mu}$.

Also, the probability of a component being in the down state is $\frac{\lambda}{\lambda+\mu}$.

$$\text{Probability of being in state 1} = \frac{\mu_1}{\mu_1+\lambda_1}\cdot\frac{\mu_2}{\mu_2+\lambda_2}$$

$$\text{Probability of being in state 2} = \frac{\lambda_1}{\mu_1+\lambda_1}\cdot\frac{\mu_2}{\mu_2+\lambda_2}$$

$$\text{Probability of being in state 3} = \frac{\mu_1}{\mu_1+\lambda_1}\cdot\frac{\lambda_2}{\mu_2+\lambda_2}$$

$$\text{Probability of being in state 4} = \frac{\lambda_1}{\mu_1+\lambda_1}\cdot\frac{\lambda_2}{\mu_2+\lambda_2} \tag{10}$$

The most accurate method for analyzing networks including weather states is to use the Markov modeling. However, this becomes impractical for all except the simplest system. Instead, therefore, an approximate method is used based upon simple rules of probability.

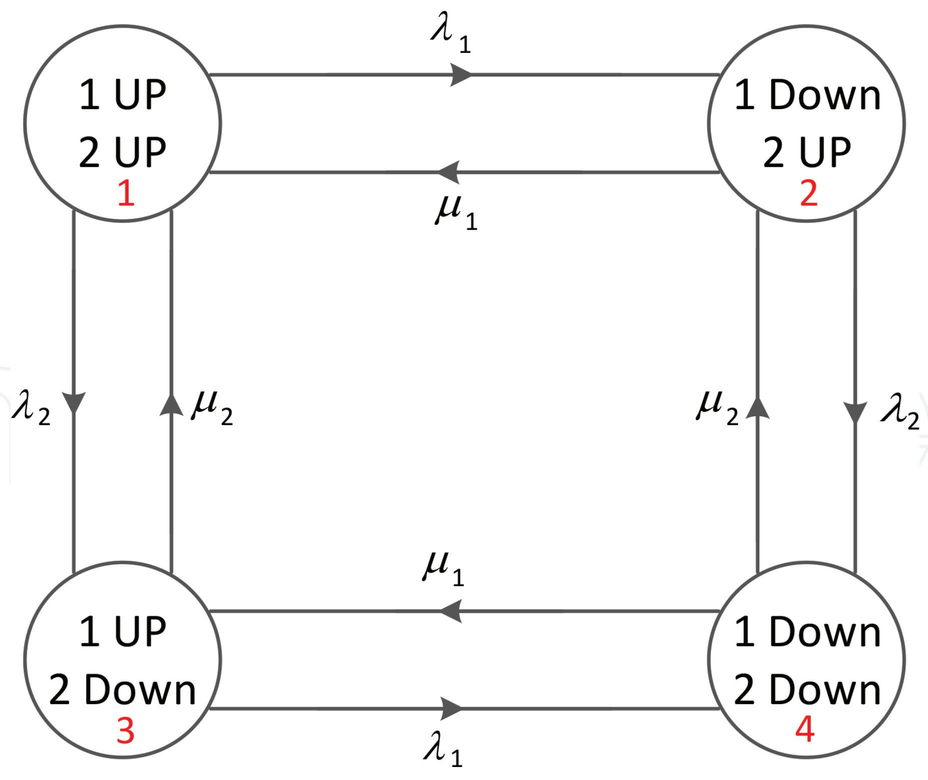


Figure 10.
State-space diagram for two-component system, where λ is the failure rate and μ is the repair rate $= \frac{1}{r}$ (r = repair time).

7.3.2 Series components

The requirement is to find the reliability indices of a single component that is equivalent to a set of series-connected components as shown in **Figure 11**.

If the components are in series from a reliability point of view, both must operate, i.e., be in upstate, for the system to be successful, i.e., the upstate of a series system is state 1 of the state-space diagram shown in **Figure 11**.

From the above equation (state 1), the probability of being in this upstate is

In addition, since $\mu = \frac{1}{r}$, the above equation becomes

$$r_s = \frac{\lambda_1 r_1 + \lambda_2 r_2 + \lambda_1 \lambda_2 r_1 r_2}{\lambda_s} \tag{11}$$

$$= \frac{\lambda_1 r_1 + \lambda_2 r_2}{\lambda_s} \tag{12}$$

$$= \frac{\sum_{i=1}^{n} \lambda_i r_i}{\lambda_s} \tag{13}$$

Also, the rate of transition from state 1 of the two-component state-space diagram is $\lambda_1 + \lambda_2$, therefore

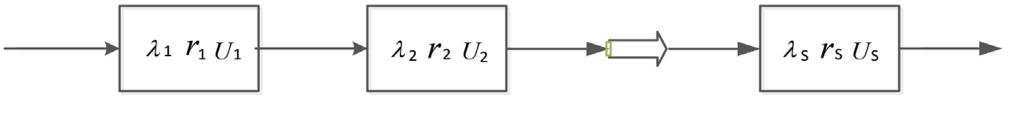


Figure 11.
State-space diagram for two-component system.

$$\lambda_s = \lambda_1 + \lambda_2 = \sum_{i=1}^{n} \lambda_i \tag{14}$$

$$r_s = \frac{\sum_{i=1}^{n} \lambda_i \, r_i}{\sum_{i=1}^{n} \lambda_i} \tag{15}$$

Thus, the unavailability for series systems (U_S) can be expressed as

$$U_S = \lambda_s \, r_s \tag{16}$$

$$= \sum \lambda \, r \tag{17}$$

In particular, the order of evaluation is usually $\lambda_s (= \sum \lambda)$, $U_s (= \sum \lambda \, r)$ and $r_s (= U_s / \lambda_s)$.

Although these equations were derived from the assumption of exponential distribution, they are expected or average values and can be shown to be valid irrespective of the distribution assumption.

7.3.3 Parallel components

Many systems consist of both series and parallel connections. These systems can be seen in transmission lines, in combinations of transformers, cables, feeders, relays, protection and control devices, etc. As an example, **Figure 12** displays two parallel lines that are both connected in series with another line. In these situations, and from a reliability point of view, it is essential to consequently reduce the network in order to estimate its overall reliability. This is accomplished by repeatedly combining sets of parallel and series components into equivalent network components until a single component remains. The reliability of the last component is equal to the reliability of the original system (**Figure 12**).

In this case, the requirement is to find the indices of a single component that is equivalent to two parallel components as shown in **Figure 12**.

If the components are in parallel from a reliability point of view, both must fail for resulting in a system failure, i.e., the down state of a parallel system is state 4 of the state-space diagram shown in **Figure 10**. From (10), the probability of being in this downstate is

$$\frac{\lambda_1 \lambda_2}{(\mu_1 + \lambda_1)(\mu_2 + \lambda_2)} = \frac{\lambda_p}{\lambda_p + \mu_p} \tag{18}$$

Also, the rate of transition from state 4 of the two-component state-space diagram is $\mu_1 + \mu_2$.

Therefore $\mu_p = \mu_1 + \mu_2$

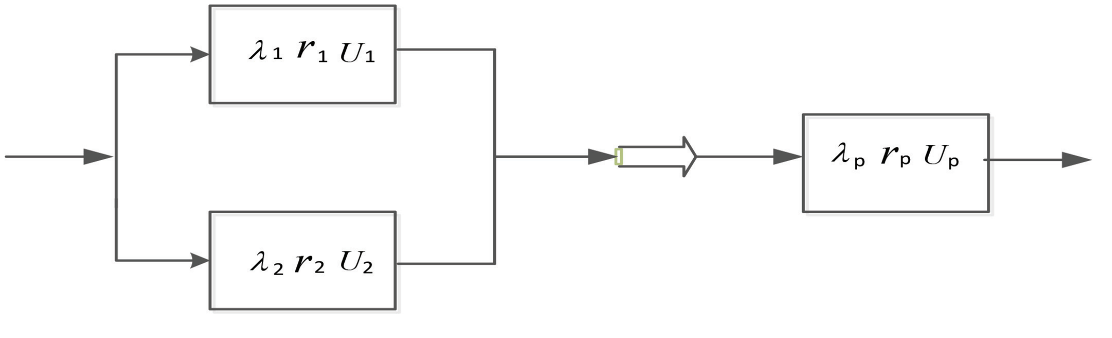


Figure 12.
State-space diagram for a two-component system.

$$\frac{1}{r_p} = \frac{1}{r_1} + \frac{1}{r_2} \tag{19}$$

or

$$r_p = \frac{r_1\, r_2}{r_1 + r_2} \tag{20}$$

From the above equations, it yields that

$$\lambda_p = \frac{\lambda_1\, \lambda_2 (r_1 + r_2)}{1 + \lambda_1 r_1 + \lambda_2 r_2} \tag{21}$$

$$= \lambda_1 \lambda_2 (r_1 + r_2) \tag{22}$$

Thus, the unavailability for parallel systems $\left(U_p\right)$ can be expressed as

$$U_p = \lambda_p r_p \tag{23}$$

In practice, the order of evaluation is usually

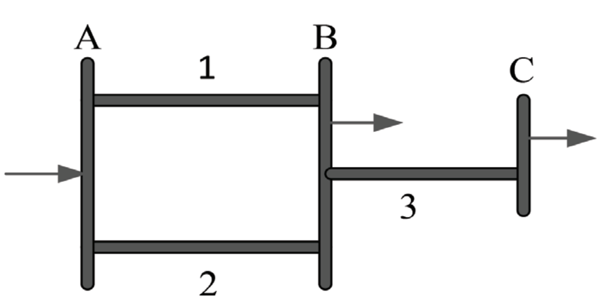
$$\lambda_s = \sum \lambda \qquad U_s = \sum \lambda\, r \qquad \text{and} \qquad r_s = \frac{U_s}{\lambda_s}$$

Although these equations were derived from the assumption of exponential distribution, they are expected or average values and can be shown to be valid irrespective of the distributional assumption.

Example (series/parallel): To illustrate the applications of these techniques, let us consider the transmission lines supplying the newly large industrial park constructed near Riyadh city (the capital of the KSA) within what is called "industrial cities" in the main cities of the KSA. The transmission lines with their data load points are given below (see **Figure 13**). It is required to evaluate the load point (busbar) reliability indices at busbars B and C.

To find the indices at busbar B, lines 1 and 2 must be combined in parallel using Eq. (22):

$$\begin{aligned} \lambda_B &= \lambda_1\, \lambda_2\, (r_1 + r_2) \\ &= 0.5 \times 0.5(5+5)/8760 \\ &= 2.854 \times 10^{-4} f/y \end{aligned}$$



Line #	(f / yr)	r (hrs.)
1	0.5	5
2	0.5	5
3	0.1	10

Figure 13.
Transmission lines configuration with data load points.

where 8760 is the total number of hours in a year, using Eq. (20)

$$\begin{aligned} r_B &= \frac{r_1\, r_2}{r_1 + r_2} = \frac{5 \times 5}{5 + 5} = 2.5\ \text{h.} \\ U_B &= \lambda_B r_B \\ &= 2.854 \times 10^{-4} \times 2.5/8760 \\ &= 8.145 \times 10^{-8}\ \text{yrs/yrs} = \textit{probability} \\ &= 7.135 \times 10^{-4}\ \text{h/yrs.} \end{aligned}$$

To find indices at busbar C, lines 1 and 2 must be combined in parallel (as done above) and then combined with line 3 in series, using Eq. (14):

$$\begin{aligned} \lambda_C &= \lambda_B + \lambda_3 \\ &= 2.854 \times 10^{-4} + 0.1 \\ &= 1.003 \times 10^{-1} f/yr \\ r_C &= \frac{U_B + \lambda_3 r_3}{\lambda_C} \\ r_C &= \frac{7.135 \times 10^{-4} + 0.1 \times 10}{1.003 \times 10^{-1}} \\ &= 9.977\ \text{h.} \end{aligned}$$

Using Eq. (23)

$$\begin{aligned} U_C &= \lambda_C r_C \\ \therefore U_C &= 1.003 \times 10^{-1} \times 9.977 \\ &= 1.001\ \text{h/yrs.} \end{aligned}$$

In this case, it is seen that the indices of busbar C are dominated by the indices of line 3. This is clearly expected since busbar C will be lost if either line 3 or lines 1 and 2 simultaneously fail. Consequently, loss of line 3 is a first-order event, and loss of lines 1 and 2 are a second-order event. It must be stressed that this is only true if the reliability indices of the components are comparable; if the component forming the low-order event is very reliable and the components forming the higher order events are very unreliable, the opposite effect may occur.

7.3.4 Network reduction for failure mode analysis

In some cases, some critical or unreliable areas become absorbed into equivalent elements and become impossible to identify. The alternative is to impact the system and compose a list of failure nodes, i.e., component outages that must overlap to cause a system outage. These overlapping outages are effectively parallel elements and can be combined using the equations for parallel components. Any one of these overlapping outages will cause system failure and therefore, from a reliability point of view, are effectively in series. The system indices can therefore be evaluated by applying the previous series equations to these overlapping outages.

The following case study showcases the existing tie-line interconnecting the eastern region (ER) with the central region (CR) (400 km apart) in the Kingdom of Saudi Arabia (KSA). The ER is actually the incubator of the oil industry and all its refineries and infrastructures. Riyadh is located in the CR, which is the domicile of the Saudi Electric Company (SEC). The latter is envisioning tremendous expansion with vast increasing industrial future loads. Therefore, a huge bulk of electric power is transferred from the ER to the CR via the interconnecting tie-line. Therefore, to evaluate its reliability using the concepts and methodology stated above, the tie-line (see **Figure 14**) is considered bearing the following data:

a. Using network reduction

Combing elements 1 and 3 in series as in Eq. (12) gives:

$$r_{1,3} = \frac{\lambda_1 r_1 + \lambda_3 r_3}{\lambda_s} = \frac{0.5 \times 10 + 0.01 \times 100}{0.51} = 11.76 \quad \text{hr}$$

The indices of components 2 and 4 combined will be identical:

$$r_{2,4} = \frac{\lambda_2 r_2 + \lambda_4 r_4}{\lambda_s} = \frac{0.5 \times 10 + 0.01 \times 100}{0.51} = 11.76 \quad \text{hr}$$

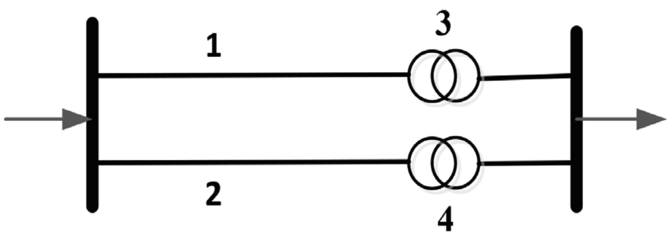
The indices for the load point are

$$\lambda_s = 6.984 \times 10^{-4} \ f/y \quad r_2 = 5.88 \ \text{hr}$$

$$U_s = 4.1066 \times 10^{-3} \quad \text{hr/yr}$$

b. Using failure modes analysis

Overlapping outages	λ (*f/yr*)	*r* (h)	*U* h (h/yr)
1 and 2	5.7080×10^{-14}	5	2.854×10^{-14}
1 and 4	0.6279×10^{-14}	9.091	5.708×10^{-14}
2 and 3	0.6279×10^{-14}	9.091	5.708×10^{-14}
3 and 4	0.0228×10^{-14}	50	1.142×10^{-14}
	$6.987 \times 10^{-14} = \lambda_s$	$5.88 = r_s$	4.110×10^{-14} $\lambda_s \times r_s$



Component	λ (f / yr)	r (hrs.)
1	0.5	10
2	0.5	10
3	0.01	100
4	0.01	100

Figure 14.
The tie-lines configuration with data load points.

Although the second method seems longer, it is worth noting that it gives a greater deal of information. It indicates that the failure rate and unavailability are mainly due to the overlapping failures of the two lines; however, the average outage duration is mainly due to the overlapping outages of the two transformers. This information, which is vital in assessing critical areas and indicating the areas requiring more investment, is not given by the network reduction technique.

8. Customer-based reliability indices

The most widely used reliability indices are averages that weight each customer equally. Customer-based indices are popular with electric companies [14] since a small residential customer has just as much importance as a large industrial customer. Regardless of the limitations they have, these are generally considered acceptable techniques showing adequate measures of reliability. Indeed, they are often used as reliability benchmarks and improvement targets. The formulae for customer-based indices include:

8.1 System average interruption frequency index (SAIFI)

SAIFI is a measure of how many sustained interruptions an average customer will experience over the course of a year. This measure can be defined as

$$\mathrm{SAIFI} = \frac{\text{Total number of customers interruptions}}{\text{Total number of customers served}}\ (\text{inter/cust}) \tag{24}$$

For a fixed number of customers, the only way to improve SAIFI is to reduce the number of sustained interruptions experienced by customers.

8.2 System average interruption duration index (SAIDI)

SAIDI is a measure of how many interruption hours an average customer will experience over the course of a year. For a fixed number of customers, SAIDI can be improved by reducing the number of interruptions or by reducing the duration of these interruptions. Since both of these reflect reliability improvements, a reduction in SAIDI indicates an improvement in reliability. This measure can be defined as

$$S\mathrm{AIDI} = \frac{\text{Total customers interruptions durations}}{\text{Total number of customers served}}\ (\text{h/cust}) \tag{25}$$

8.3 Customer average interruption duration index (CAIDI)

CAIDI is a measure of how long an average interruption lasts and is used as a measure of utility response time to the system contingencies. CAIDI can be improved by reducing the length of interruptions but can also be reduced by increasing the number of short interruptions. Consequently, a reduction in CAIDI does not necessarily reflect an improvement in system reliability. This measure can be defined as

$$\mathrm{CAIDI} = \frac{\text{Total customers interruptions durations}}{\text{Total number of customers interruptions}}\ (\text{h/cust}) \tag{26}$$

8.4 Average service availability index (ASAI)

ASAI is the customer-weighted availability of the system and provides the same information as SAIDI. Higher ASAI values reflect higher levels of system reliability. This measure can be defined as

$$\mathrm{ASAI} = \frac{\text{Customer hours service availability}}{\text{Customer hours service demand}}\ (\mathrm{pu}) \tag{27}$$

9. Conclusions

This chapter consists of eight sections that can be briefly summarized as follows:

Section 1 starts with an introduction that indicates the importance and viable role of reliability evaluation in power system planning with selected relevant references to its nature subject matter.

Section 2 discusses the types of equipment outages, particularly the severe ones that may cause the machine(s) to be out of service unexpectedly in critical conditions that can compromise the ability of the system to supply the load.

Section 3 reviews some basic theories, assumptions, and mathematical expressions for the reliability evaluation such as the well-known "loss of load expectation" index and with other important complementary reliability indices.

Section 4 exhibits a new computation method for the energy produced by each generating unit loaded to the system.

Section 5 demonstrates how the reliability indices can be of significant tools in assessing system planners to arrive at the most appropriate reliability levels that can assure both continuous supply as well as maintaining the least operating cost.

Section 6 highlights the main merits and advantages of electrical interconnection among dispersed and isolated power systems from an economic and reliability point of view.

Section 7 shows the application of the frequency and duration (F&D) indices used in reliability evaluation of transmission lines and distribution networks. These indices are implemented in some industrial zones in a fast-developing country in accordance with its envisaged 2030 vision.

Section 8 reveals the most widely used customer-based reliability indices by most of the electric companies since the residential sector has just as much importance as the industrial sector. These indices show adequate measures of reliability benchmarks and improvement targets.

Appendix A. Power system costs

There are several costs that are associated with power system planning and can be manifested in the following sections.

A.1 Fixed cost

The fixed cost (FC) represents the cash flow at any stage of the planning horizon resulting from the costs of installing new generating units during the planning period. It depends on the current financial status of the utility, the type and size of generating units, and the cost of time on money invested during the planning period. The total fixed costs (FC_T) for unit(s) being installed can be computed as

$$FC_T = \sum_t \sum_k (CAP_k \cdot CC_k \cdot NU_k)^t \tag{A.1}$$

where
CAP_k: *unit capacity added to the system of type k*; -
CC_k : *capital cost of unit of type k* (*SR/kW*);
NU_k: *number of unit(s) added to the system of type k at each interval of time t.*;
t: *interval period of time considered in the planning horiozon,* $t = 1 \ldots T$.

A.2 Variable cost

The variable cost (VC) represents the cost of energy supplied by the system. It is affected by the load variation, the type and size of generating units, and the number of hours of operation. Also, these costs are related to the cost of operation and maintenance (fuel, scheduled maintenance, interim spare parts, staffing, wages, and miscellaneous expenses) and can be evaluated as

$$VC_T = \sum_t \sum_k (\epsilon ES_k \cdot ESC_k \cdot NU_k)^t \tag{A.2}$$

where ϵES_k: expected energy supplied by unit of type k; ESC_k: energy supplied cost of unit of type k (SR/kWh).

The total system costs (SC_T) for the entire expansion plan can be estimated by summing all the above individual costs at every stage of the planning period as being expressed in the following equation:

$$SC_T = FC_T + VC_T \tag{A.3}$$

A.3 Outage cost

The outage costs, i.e., the cost of the expected energy not supplied (ϵENS), were previously presented and discussed in Section 5. One method of evaluating ϵENS is described in [8]. Therefore, estimating the outage cost (OC) is to multiply the value of that ϵENS by an appropriate outage cost rate (OCR), as follows:

$$OC_T = \sum_t (\epsilon ENS \cdot OCR)^t \tag{A.4}$$

where ϵENS is the expected energy not supplied (kWh lost) and OCR is the outage cost rate in SR/kWh.

The overall cost of supplying the electric energy to the consumers is the sum of system cost that will generally increase as consumers are provided with higher reliability and customer outage cost that will, however, decrease as system reliability increases or vice versa. This overall system cost (OSC) can be expressed as in the following equation:

$$OSC_T = SC_T + OC_T \tag{A.5}$$

The prominent role of outage cost estimation, as revealed in the above equation, is to assess the worth of power system reliability by comparing this cost (OC) with the size of system investment (SC) in order to arrive at the least overall system cost that will establish the most appropriate system reliability level that ensures energy continuous flow as well as the least cost of its production.

As witnessed in **Figure 8**, the incorporation of customer outage costs in investment models for power system expansion plans is very difficult for planners in fast-developing countries. This difficulty stems principally either from the lack of system records of outage data, failure rate, frequency, duration of repair, etc. or the failure to carry out customer surveys to estimate the impact and severity of such outages in terms of monetary value.

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