CHAPTER 2

Generation Reliability Assessment

2.1 Introduction

Generation reliability is one of the most important parts in electric generation planning and it focuses on the reliability of generators in the power system where electric power is produced from the conversion process of primary energy (fuel) to electricity before transmission. In generation planning, there are various criteria in evaluating generation reliability, i.e. the proper amount of generation capacity to serve the power demand [Endrenyi, 1978; Stoll, 1989]. This chapter provides a concept of generation reliability and its assessment. This chapter is organized as follow: Section 2.2 describes power system reliability concept, Section 2.3 presents generation reliability concept and generation reliability index is described in Section 2.4. Finally, the summary of this chapter is presented in Section 2.5

2.2 Power System Reliability Concept

Power system reliability studies can be conducted for two purposes which are (a) long-term reliability evaluations and (b) short-term reliability prediction. The long-term evaluations are performed to assist in long-range system planning while the short-term reliability predictions are sought to assist in day-to-day operation decisions, including system security assessment where the effects of sudden disturbances are evaluated [Endrenyi, 1978].

Power system reliability may be divided into adequacy and security. System adequacy is considered to be the existence of sufficient capacity to serve the power demand, while system security is the ability to withstand certain disturbances [Billinton and Allan, 1996]. In the system adequacy domain, system reliability evaluations can be divided into deterministic and probabilistic.

The most common deterministic indices are the reserve margin and the loss of largest unit. Generation reserve margin seems to be the most intuitive and easily criterion. The reserve margin (capacity) is the generation capacity exceeding the peak demand. By considering the loss of largest unit, the reserve margin must also add the size of the largest unit to the reserve capacity. The risk of generation capacity deficit may be defined as the probability that the power demand exceeds the capacity in service (which is installed capacity less capacity outage). Alternatively, the capacity deficit can also be defined as the equivalent load (the sum of power demand and outage capacity) exceeds the installed capacity.

However, the deterministic approach does not account for the stochastic nature of system behavior but the probabilistic approach accounts. There are several indices in the probabilistic approach which are used in generation capacity adequacy analysis. The most common probabilistic indices are the loss of load probability (LOLP), the loss of load expectation (LOLE), the loss of energy expectation (LOEE) or the Expected Energy Not Supplied (EENS). Furthermore, the contribution of the unit to supply adequacy of the system can be represented by using Capacity Credit (CC).

In the probabilistic approach, there are a number of computational methods for generation reliability such as Monte Carlo simulation [Billinton and Chen, 1998; Billinton and Bai, 2004; Wangdee and Billinton, 2006; Vallee, Lobry and Deblecker, 2008; Billinton et al., 2012], analytical methods [Voorspools and D’haeseleer, 2006; Chaiamarit and Nuchprayoon, 2013], and fuzzy mathematics [Narasimhan and Asgarpoor, 2000; El-Tamaly and ElBaset Mohammed, 2006]. The computation procedure of generation reliability is tedious and can be evaluated by using a number of reliability indices. Consequently, the contribution of generating unit on reliability is subjective and depends on the reliability index being considered. The category of the power system reliability and generation reliability indices can be shown in Figure 2.1.

This research focuses on power system adequacy domain which is the generation reliability assessment for long-term evaluations. The probabilistic approach is preferred to use in the generation reliability assessment.

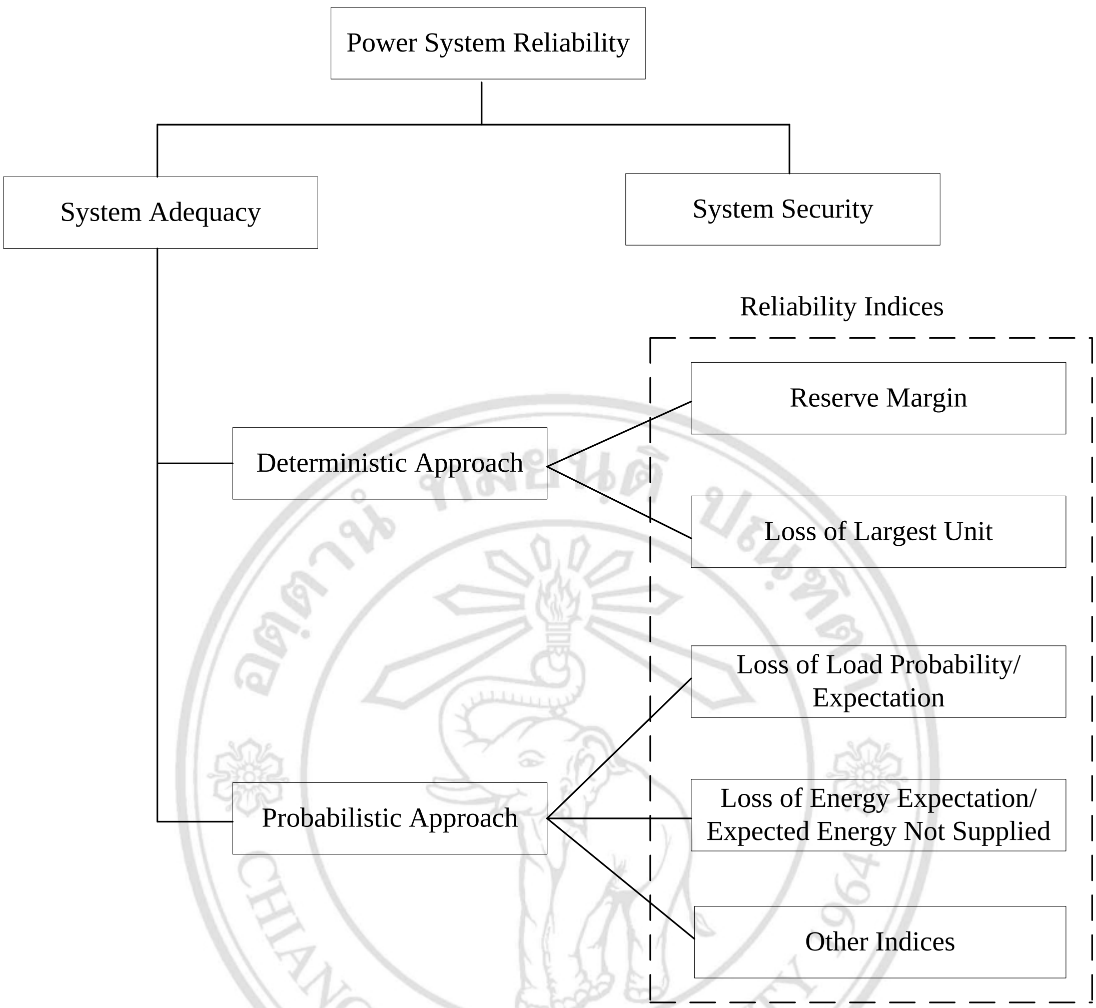


Figure 2.1 Category of power system reliability and reliability indices.

2.3 Generation Reliability Concept

Generation reliability focuses on the reliability of generators in the power system where electric power is produced from the conversion process of primary energy (fuel) to electricity before transmission. In the generation system studies, the generation reliability assessment is usually in a term of generation system adequacy assessment. Thus, the transmission system is ignored and treated as a load point.

The basic elements in generation reliability assessment consist of generation model, load model, and risk model [Billinton and Allan, 1996] as shown in Figure 2.2.

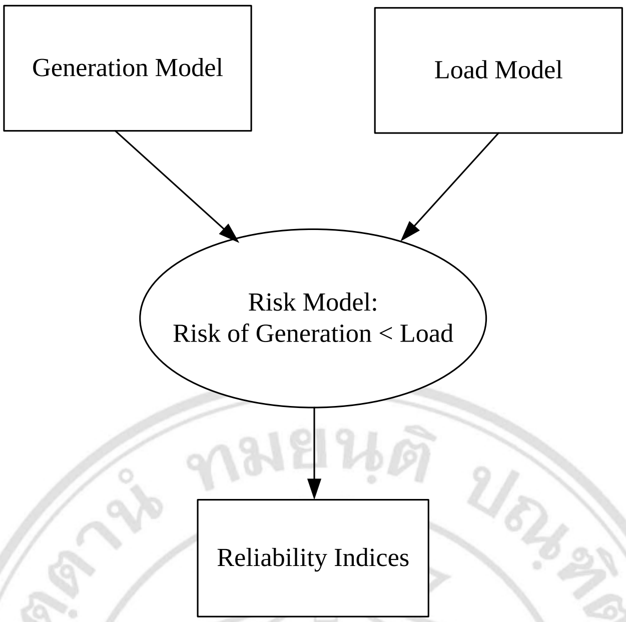


Figure 2.2 Elements of generation reliability assessment [Prada, 1999].

The generation model and the load model are convolved to form the risk model. After that, probabilistic estimates of risk are used as reliability indices. The generation model which is used for generation capacity adequacy assessment is a capacity outage probability table (COPT) which can be created by using the recursive technique. As for the load model, the daily peak load or hourly load for a period of one year is normally used to form the load duration curve (LDC) or the load probability table (LPT).

2.3.1 Generating Unit Model

Two important variables of the generation model which are used in generation adequacy assessment are the generation capacity and the failure probability of the unit.

If the generation unit is described by a two-state model in the concept of availability as shown in Figure 2.3. The probability of failure is defined as the unit unavailability by a traditional form, known as Forced Outage Rate (FOR). FOR is not a rate in modern reliability terms, since it is a ratio of two time values as shown in (2.1) and the unit availability is shown in (2.2) [Billinton and Allan, 1996].

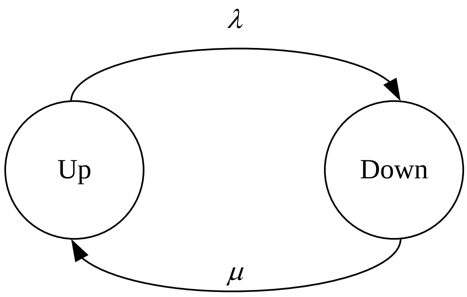


Figure 2.3 Two-state model (Billinton and Allan, 1996).

$$Unavailability\ (FOR) = U = \frac{\lambda}{\lambda+\mu} = \frac{r}{m+r} = \frac{r}{T} = \frac{f}{\mu}, \\ = \frac{\sum[down\ time]}{\sum[down\ time]+\sum[up\ time]}, \tag{2.1}$$

$$Availability = A = \frac{\mu}{\lambda+\mu} = \frac{m}{m+r} = \frac{m}{T} = \frac{f}{\lambda}, \\ = \frac{\sum[up\ time]}{\sum[down\ time]+\sum[up\ time]}, \tag{2.2}$$

where λ is an expected failure rate, μ is an expected repair rate, m is mean time to failure (MTTF) = $1/\lambda$, r is mean time to repair (MTTR) = $1/\mu$, $m+r$ is mean time between failures (MTBF) = $1/f$, f is cycle frequency = $1/T$ and T is cycle time = $1/f$.

Since the concept of FOR is not a rate, FOR is defined as the fraction of time that a generating unit is unavailable for service [Endrenyi, 1978; Stoll, 1989] as shown in (2.3).

$$FOR = FOH / (FOH + SH), \tag{2.3}$$

$$FOH = probability\ of\ failure \times mean\ time\ to\ repair, \tag{2.4}$$

where the Service Hour (SH) is the time the unit is available for service and the Forced Outage Hour (FOH) is the time the unit is unavailable. The FOH is computed from the probability of failure (unavailability) and the mean time to repair.

However, the generating unit model can be represented as a multi-state model, in which there are some additional states such as de-rated state, partial failure, etc. A multi-state model is therefore required to more accurately represent the generation capacity model. A state space diagram of the unit with partial output state or de-rated state is shown in Figure 2.4 which λ_j and μ_j represents the failure rate and repair rate of unit *j*.

The probability of each outage state can be represented by the capacity outage probability table.

2.3.2 Capacity Outage Probability Table

Capacity Outage Probability Table (COPT) is a table contains all the capacity states, in an ascending order of outages magnitude together with its associated probabilities of existence. There are many ways to create and manipulate the COPT. The maximum number of available (or unavailable) capacity states in an *N*-unit system is 2^N.

For example, a 3-unit system (Unit A, Unit B and Unit C; each unit is non-identical two-state unit) will have 2^3 = 8 states of available capacity [Billinton and Allan, 1983]. The 8 states are shown in the Table 2.1.

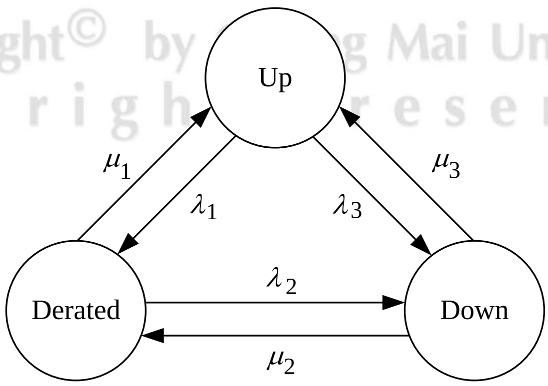


Figure 2.4 State space diagram of a unit with de-rated state [Billinton and Allan, 1983].

Table 2.1 State space of 3- unit system.

State	Unit		
	A	B	C
1	Up	Up	Up
2	Up	Up	Down
3	Up	Down	Up
4	Down	Up	Up
5	Up	Down	Down
6	Down	Up	Down
7	Down	Down	Up
8	Down	Down	Down

The basic statistic used in developing the capacity model is the probability of a generating unit being on forced outage, i.e. the forced outage rate. If all the units in the system are identical, the COPT can be easily obtained using the Binomial distribution as follow

$$P_{nr} = {}^{N}C_{nr} U^{nr} A^{N-nr}, \tag{2.5}$$

$${}^{N}C_{nr} = \frac{N!}{nr!\left(N-nr\right)!}, \tag{2.6}$$

where P_{nr} = probability of nr units in the down state, U is unit unavailability, A is unit availability, N is number of identical units, nr is number of units in the failed state, and ${}^{n}C_{nr}$ is the number of combination of nr items from N items.

The COPT can be developed by using cumulative probability such as the probability of finding a quantity of capacity on outage equal to or greater than the indicated amount. The cumulative probability is unity at the capacity outage state more than 0 MW and the cumulative probability values decrease as the capacity outage state increases. Although this is not completely true for the individual COPT, the same general trend is followed.

Theoretically, the COPT incorporates all the system capacity. However, the table is generally truncated by omitting all capacity outages for which the cumulative probability is less than a specified amount, which is taken as 10^{-8} [Jain, Tripathy and Balasubramanian, 1995]. This can definitely save a computing time. An alternative approach can be used by rounding the table to discrete levels after combining. The capacity rounding increment used depends upon the accuracy desired. The final rounded table contains capacity outage magnitudes that are multiples of the rounding increment. The number of capacity levels decreases as the rounding increment increases, with a corresponding decrease in accuracy [Billinton and Allan, 1996].

In a practical system, all units are not identical, the Binomial distribution has limited application. The units can be combined by using basic probability concepts but it is not practical. Therefore, the recursive algorithm is used to create the COPT.

- Recursive algorithm for COPT

The COPT can be created by using the recursive technique. For a two-state unit addition, the cumulative probability of a particular capacity outage state of *X* MW after a unit of capacity *C* MW and forced outage rate *U* is added is given by [Billinton and Allan, 1996]

$$P(X) = [1-U]P'(X) + UP'(X-C), \tag{2.7}$$

where *P'(X)* and *P(X)* are cumulative probability of capacity outage state of *X* MW before and after the unit is added. The above expression is initialized by setting *P'(X)* = 1.0 for *X* ≤ 0, and *P'(X)* = 0 otherwise.

In case of de-rated states are included, (2.7) can be modified to be (2.8) to include multi-state unit representation [Billinton and Allan, 1996].

$$P(X) = \sum_{i=1}^{n} p_i P'(X - C_i), \tag{2.8}$$

where n is number of unit states, C_i is capacity outage of state i for the unit being added, p_i is probability of existence of the unit state i.

2.3.3 Load Duration Curve

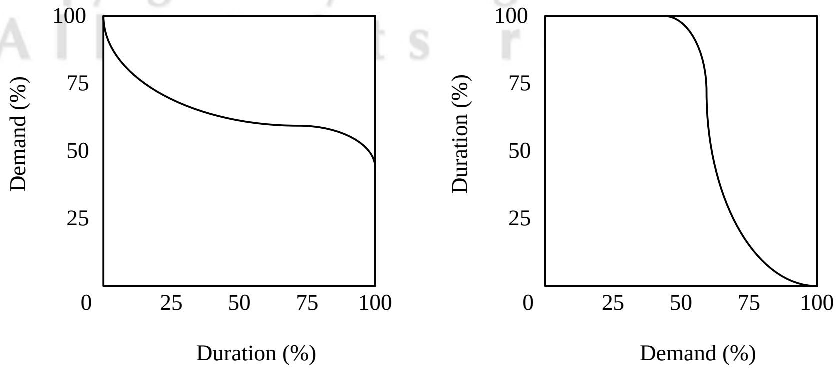
Load duration curve (LDC) is a curve which shows the load profile over a given time by arranging the chronological power demand in descending magnitude. The vertical axis is power demand and the horizontal axis is duration of time (e.g. 8760 h/y). If the axes are inverted, it is then called the inverted load duration curve (ILDC). Figure 2.5 compares the LDC and ILDC by normalizing both the power demand and the time duration.

The equivalent load can be calculate as the sum of actual demand and capacity outages (fictitious load) of all generating units using convolution procedure [Booth, 1972] as shown in (2.9).

$$F'(EL) = (1-U)F(EL) + U(EL-C), \tag{2.9}$$

where *F(●)* and *F'(●)* are old and new cumulative distribution of load level, *EL* is the equivalent load, *U* is the FOR of unit of interest and *C* is the capacity of unit of interest.

The Equivalent Load Duration Curve (ELDC) can then be obtained by using the ILDC and normalizing the duration of time. The percentage of time at a given load level may be interpreted as a probability of equivalent load [Chaiamarit and Nuchprayoon, 2013].



Load duration curve *Inverted load duration curve*

Figure 2.5 Load duration curve and inverted load duration curve (normalized form).

2.4 Generation Reliability Indices

In the probabilistic domain, there are several indices used in generation capacity adequacy analysis and power system reliability, the conventional reliability indices such as Loss of Load Probability (LOLP), Loss of Load Expectation (LOLE), Expected Energy Not Supplied (EENS), etc. The generation model and the load model are applied to compute reliability indices, the COPT and the LDC are built. The main variables which are used in the COPT calculation are the generation capacity and the FOR. Furthermore, the contribution of the unit to supply adequacy of the system can be represented as Effective Load Carrying Capability (ELCC).

2.4.1 Loss of Load Probability

The most commonly accepted (but complicated) reliability index would be the so-called Loss of Load Probability (LOLP) [Stoll, 1989; Billinton and Allan, 1996; Billinton, Ringlee and Wood, 1973]. Note that, actually, the load is not lost but the generation capacity is deficient. By computing at any given time period, the LOLP quantifies the probability that generation capacity is not sufficient to supply power demand (i.e. capacity shortage). The calculation of LOLP involves the convolution of the probability of unit availability as shown in (2.10). The availability is typically represented by the two-state model (Billinton and Allan, 1996). The availability capacity of any unit is zero with the probability equals to the FOR. The availability capacity of any unit is one with the probability equals to 1 – FOR. Typically, the LOLP is computed on an hourly basis and is in the range of 0.1-1.0 days/year [Stoll, 1989].

$$LOLP = \sum_{l} \left(prob(C = C_l) \times prob(D > C_l) \right), \tag{2.10}$$

where C is generation capacity in service, D is power demand, l is index of discretized capacity available in generation system.

For long-run and installed capacity evaluation, a cumulative load curve is used. The LOLP calculation [Billinton and Allan, 1996; Prada, 1999] is illustrated in Figure 2.6 with a load duration curve. O_k is the magnitude of the k-th outage in the system, p_k is the probability of a capacity outage of magnitude O_k.

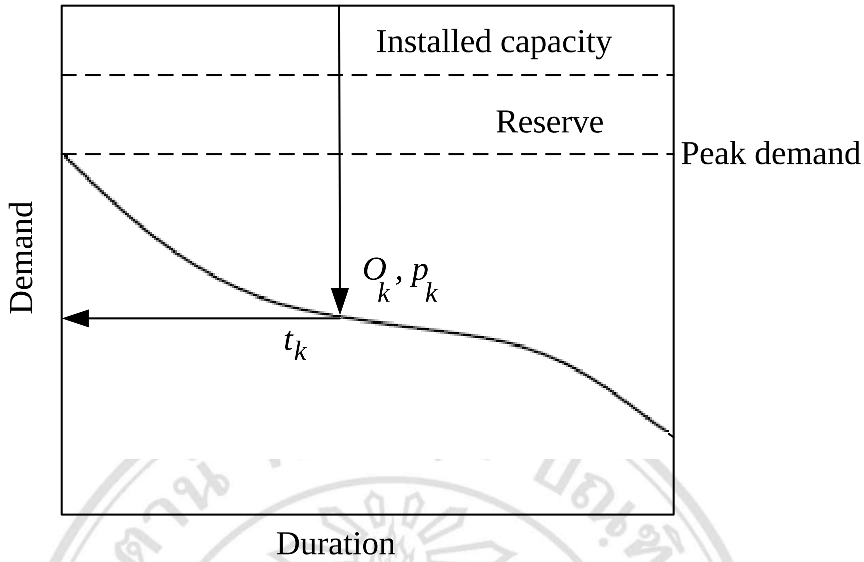


Figure 2.6 Illustration of LOLE calculation.

t_k is the time duration that an outage of magnitude O_k would cause a loss of load in the system.

Capacity outages less than the reserve will not contribute to loss-of-load risk. A particular capacity outage is greater than the reserve will contribute to the overall risk by the amount $p_k \times t_k$.

The system LOLP for the period is

$$LOLP = \sum_k p_k t_k \rightarrow LOLE\,. \tag{2.11}$$

(2.11) is an expected value instead of a probability, and it is also known as the loss of load expectation LOLE. When the daily peak load curve is used, the value of LOLE is in days for the period of study, usually days per year.

2.4.2 Loss of Energy Expectation/ Expected Energy Not Supplied

The Loss of Energy Expectation (LOEE), sometimes known as the Expected Energy Not Supplied (EENS), is the expected energy that will not be supplied power demand by the generating system due to those occasions when the load demand exceeds available generating capacity [Billinton and Allan, 1996; Prada, 1999].

The LOEE or EENS is given by

$$LOEE = EENS = \sum_k p_k E_k \,, \tag{2.12}$$

where E_k is an energy curtailed as shown in Figure 2.7.

2.4.3 Effective Load Carrying Capability

Effective Load Carrying Capability (ELCC) is defined as a measure of the contribution that an individual generator (or group of generators) makes to overall resource adequacy. The concept is illustrated graphical in Figure 2.8 [Garver, 1966].

The ELCC is the horizontal distance between the annual risk functions before and after a unit addition. The measurement of effective load carrying capability is made at some designated level of reliability, often the level calculated for the system in a previous year. The effective capability of a new unit is therefore the load increase that the system may carry with the designated reliability [Garver, 1966]. The reliability indices which are mostly used are Loss of Load Probability (LOLP) or Loss of Load Expectation (LOLE).

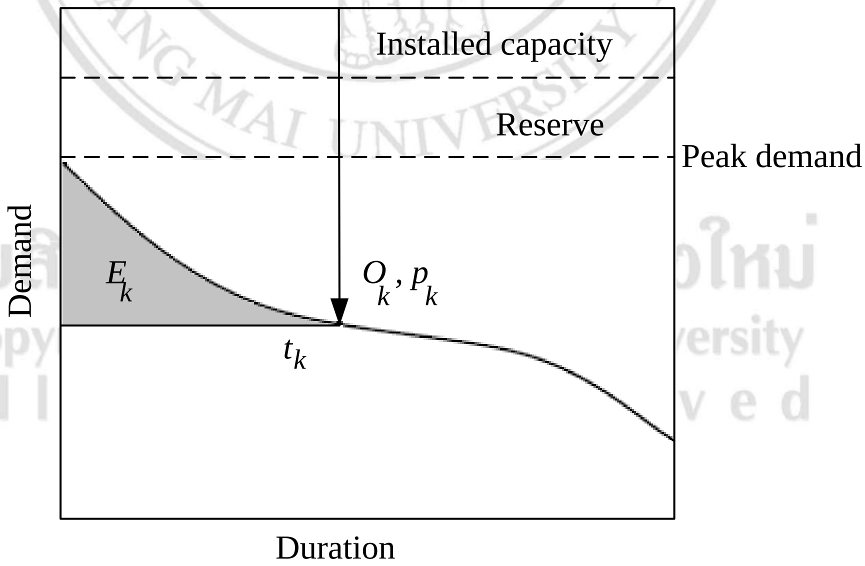


Figure 2.7 Illustration of EENS calculation.

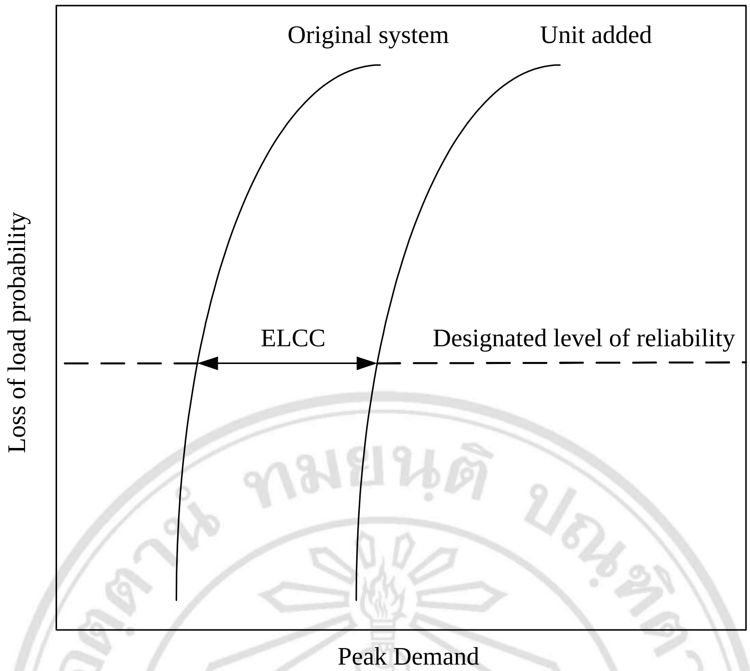


Figure 2.8 Illustration of ELCC calculation.

2.5 Chapter Summary

This chapter presents the concept of power system reliability and the concept of generation reliability. The generation reliability index and the generation reliability assessment are also mentioned by focusing on power system adequacy domain which is the generation reliability assessment for long-term evaluations.