CHAPTER 2

Methodology of the Study

2.1 Distribution reliability

Distribution reliability is the ability of the distribution system to perform its function under stated conditions for a stated period of time without failure. Distribution reliability is becoming significantly important in the current competitive climate because the distribution system feeds customers directly [13].

Frequency and duration of electrical outages related to the reliability of the distribution system. If reliability is regarded as the technical regulations index in order to analyze the reliability, it must be included in the operating cost of outages. The comparison to the total cost of outage indices will be useful in planning for developing a system.

2.2 Reliability theory

The reliability theory is the science of assessing what proportion of time and a statistical representation of the failure rate and repair duration time for a power system component. For example, a line might suffer an outage due to a short circuit. After the outage, repairs will begin and the line will be put into service again after a successful repair [14]. If two states for line A are defined as ‘in service’ and ‘under repair’, monitoring of the line could result in a time sequence of outages and repairs as depicted in Figure 2.1.

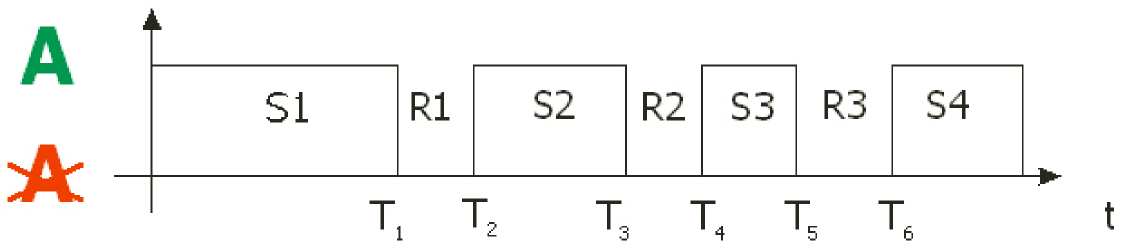

Figure 2.1 Component timeline with two states.

Line A in this example fails at time T_1 after which it is repaired and put back into service at T_2. It fails again at T3, is repaired again, etc. The repair durations $R1=T_2-T_1$, $R2=T_4-T_3$, etc.

The repair durations are also called the 'Time To Repair' (TTR). The service durations $S1=T_1$, $S2= T_3-T_2$, etc. are called the 'life time'or 'Time To Failure' '(TTF).

Both TTR and TTF are stochastic quantities. By gathering failure data about a large group of similar components in the power system, statistical information about TTR and TTF, such as the mean value and standard deviation, can be calculated. The statistical information is then used to define a stochastic model.

There are many ways in which to define a stochastic model. The so-called homogenous Markov model is a highly simplified but generally used model. A homogenous Markov model with two states is defined by:

- A constant failure rate λ; and
- A constant repair rate μ.

$$\text{Where } \lambda = \frac{Number\ of\ \ failures}{Total\ operating\ time\ of\ \ units} \qquad (1)$$

These two parameters can be used to calculate the following quantities:

- Mean time to failure, TTF =1/ λ;
- Mean time to repair, TTR =1/ μ;
- Availability, P= TTF/(TTF+TTR);
- Unavailability Q = TTR/(TTF+TTR);

The availability is the fraction of time when the component is in service; the unavailability is the fraction of time when it is in repair; and P + Q = 1.0.

2.3 Failure Effect Analysis in reliability assessment

Failure Effect Analysis (FEA) analysis for the network assessment could consideration or ignore constraints. For generated and enumerated, the input contingency topology is checked to see of it is within the limits set in the analysis options. This is the most comprehensive step of the assessment algorithm. If constraints are not considered by the FEA, then a load-flow for each state is not required and consequently the simulation is much faster.

For every simulated failure, a contingency is created by the FEA algorithm. If the calculation uses load characteristics, contingency is created for every combination of failure and load state. Likewise, when maintenance (planned outages) is considered, there are more states for each outage and contingency combination.

2.3.1 Fault Clearance

The fault clearance step of the FEA assumes of the protection. Therefore, it is assumed that the nearest relays to the failure will clear the fault. If protection/switching failures are considered in the FEA, it is assumed that the next closest protection device (after the failed device). As described in (Protection/Switch Failures), PowerFactory does not consider separate switch and protection failures, instead these are lumped together. In the pre-processing phase of the reliability assessment, all breakers in the system that can be tripped by a relay or fuse are marked as 'protection breakers'. Figure 2.2 shows a simple network containing four loads, several circuit breakers (CB) and disconnections switch (DS) and a back-feed switch (BF). The possible load interruptions caused by a fault on 'Ln4' will now be investigated.

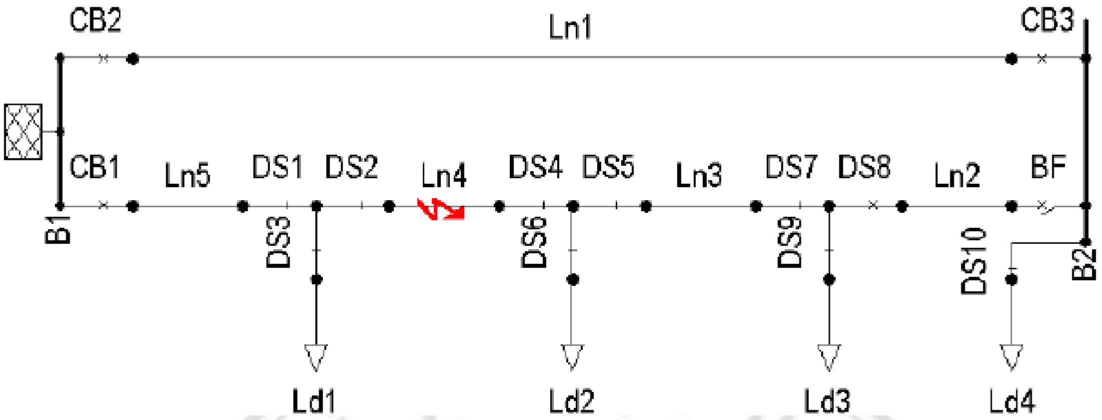

Figure 2.2 Short-Circuit on Ln4.

To clear the fault, the FEA starts a topological search from the faulted components to identify the closest protection breaker/s that can clear the fault. These breakers are then opened to end the fault clearance phase of the FEA. If it is not possible to isolate the fault because there are no appropriate protection breakers, then an error message will be printed and the reliability assessment will be terminated.

The area is isolated by the fault clearance procedure is called the 'protected area'. Figure 2.3 shows the example network after the fault clearance functions have opened the protection breaker 'CB1'. The protected area is the area containing all switches, lines and loads between 'CB1' and the back-feed switch, 'BF'. Therefore, during the clearance of this fault, loads 1, 2, and 3 are interrupted.

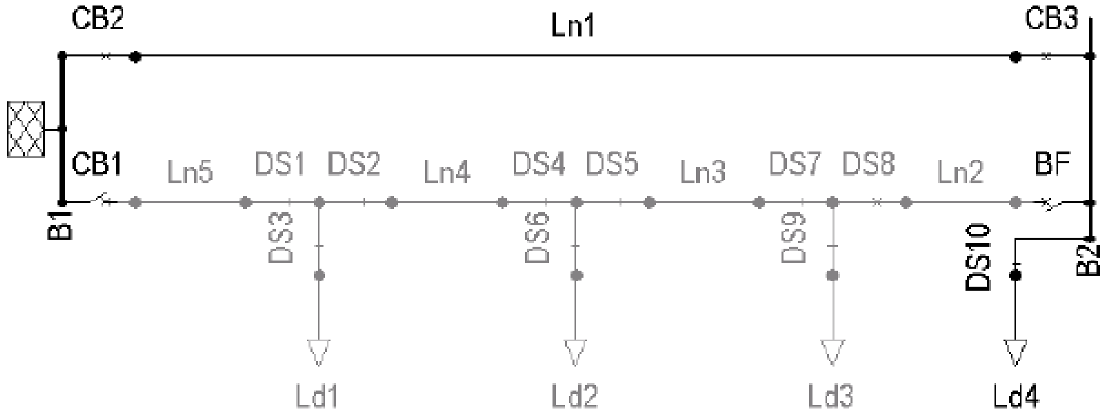

Figure 2.3 Protected area.

2.3.2 Fault separation

The next step of the FEA is to attempt to restore power to healthy network sections. It does this by separating the faulted section from the health section by opening sectionalizing switches.

The fault separation procedure uses the same topological search for switches as the fault clearance phase. The fault separation phase starts a topological search from the faulted components to identify the closest switches that will isolate the fault. These switches are subsequently opened. Note, all closed switches can be used to separate the faulted area. The area that is enclosed by the identified fault separation switches is called the 'separated area'. The separated area is smaller than, or equal to, the 'protected area'. It will never extend beyond the 'protected area'.

The healthy section which is inside the 'protected area', but outside of the 'separated area' is called the 'restorable area' because power can be restored to this area. Figure 2.4 shows the example network with the separation switches, 'DS2' and 'DS4' open. The separated area now only contains the faulted line, Ln4.

There are now two restorable areas following the fault separation; the area which contains loads 1, and the area which contains loads 2 and 3.

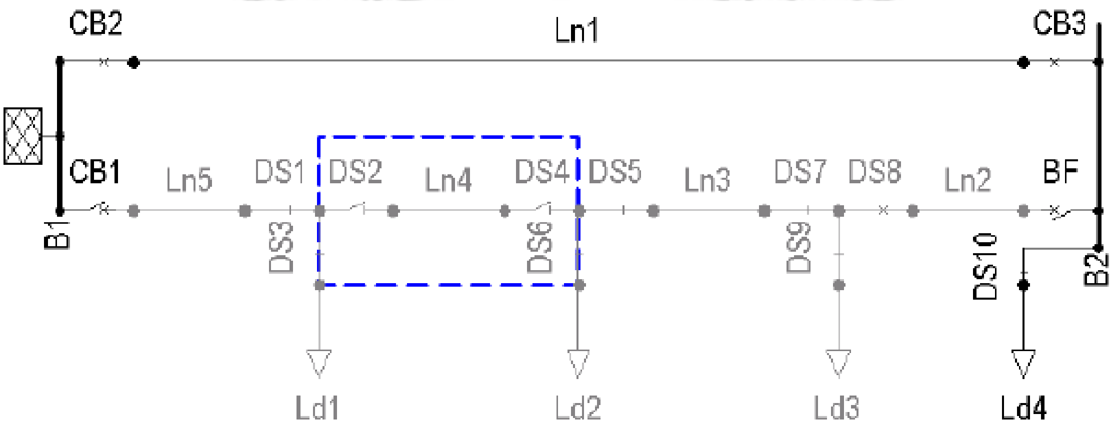

Figure 2.4 Separated area highlighted.

2.3.3 Power restoration

If we consider the previous example after the fault separation phase is complete, the following switch actions are required to restore power to the two separate 'restorable' areas:

- Separation switch 'DS2' is 'remote-controlled' and has a switching time of 3 minutes. Power to load 1 is restored by (re)closing the protection breaker, 'CB1' which is also remote controlled. Load 1 is therefore restored in 3 minutes (=0.05 hours).

- Power to load 2 and 3 is restored by closing the back-feed switch, 'BF'. Because the back-feed switch has an actuation time of 30 minutes, loads 2 and 3 are restored in 0.5 hours. The network is now in the post-fault condition as illustrated in Figure 2.5.

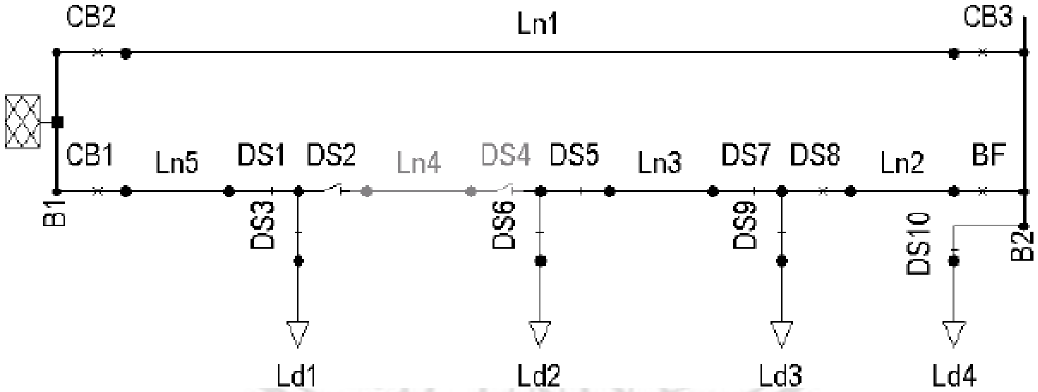

Figure 2.5 Power Restoration by Back-Feed Switch BF1 and CB1.

2.4 Reliability indices

Reliability indices are statistical data of reliability for a given value of the load as well customers [15]. Most reliability indices are average values of reliability, especially if the system features regional service stations or feeder. Comprehensive treatment is not practical; the reliability indices are used around the world. The utility indices have traditionally only included disruptions in the long term (usually defined as interruptions longer than 5 minutes), which is a common way to define reliability in terms of customers and load based indices.

Most utilities commonly use the following two reliability indices for frequency and duration to quantify the performance of their system [16].

- System Average Interruption Frequency Index (SAIFI) is designed to give information about the average frequency of sustained interruptions per customer over a predefined area:

$$SAIFI = \frac{Total\ Number\ of\ Customers\ Interruption}{Total\ Number\ of\ Customers\ Served} = \frac{\sum \lambda_i N_i}{\sum N_T} \tag{2}$$

where N_T = Total number of customers served of the areas.

N_i = Number of interrupted customers for each sustained interruption even during the reporting.

λ_i = the failure rate.

- System Averages Interruption Duration Index (SAIDI) is commonly referred to as customer minutes of interruption or customer hours, and is designed to provide information about the average time that the customers are interrupted:

$$SAIDI = \frac{Sum\ of\ Customer\ Interruption\ Duration}{Total\ Number\ of\ Customer\ Served} = \frac{\sum \lambda_i r_i N_i}{\sum N_T} \tag{3}$$

where r_i = Restoration time for each interruption event.

N_T = Total number of customers served of the areas.

N_i = Number of interrupted customers for each sustained interruption even during the reporting.

λ_i = the failure rate.

- Customer Average Interruption Duration Index (CAIDI) is the average time needed to restore service to the average customer per sustained interruption:

$$CAIDI = \frac{Sum\ of\ Customer\ Interruption\ Duration}{Total\ Number\ of\ Customer\ Interruption} = \frac{\mathrm{SAIDI}}{\mathrm{SAIFI}} = \frac{\sum r_i N_i}{\sum \lambda_i N_i} \tag{4}$$

where r_i = Restoration time for each interruption event.

N_i = Total number of customers served of the areas.

2.5 Reliability analysis

Reliability analysis of an electrical distribution system is considered as a tool for the planning engineer to ensure a reasonable quality of service. It allows a choice between different system expansion plans that cost wise are comparable when considering system investment and the cost of losses [17].

Main used methods for analyzing the reliability of the distribution system is simulating drawing method and solution analysis of mathematical model. The analysis is based on assumption about the basis of the statistical distribution of failure rates and repair. The reliability index analysis method is usually based on the failure mode analysis and use series equation and parallel networks. A common index used for the analysis: expected failure rate (λ) the average outage time (r) and the annual expected (U), which is a sufficient radial system.

2.6 Improving of reliability

Reliability improvement is based on power interruption statistical data. The data are analyzed for an impact in each area and the failure rate of main circuit is used to select the feeder of which a number of interruptions should be reduced. The data comprises date and time of interruption, operating equipment, outage duration and cause of the interruption.

The reliability improvement of distribution system in terms of determining the improvement of the distribution system is as follows:

- Maintenance: Corrective maintenance, preventive maintenance such as tree cut, change new conductor from small to big, change or replace old equipment, etc., time based or periodic maintenance is to reduce both the momentary and sustained outage frequency.

- Distribution automation system (DAS) optimizes a utility's operation and directly improves the reliability of its distribution power system. In consideration about DAS, it can remotely operate power switches through a proper communication method and automatically recognize faulty areas in a control center. If installing several automated switches which is economical than recloser, it is mere suitable reliable solution for the area.

The concept is applicable to multi-source loop system without communication system for data exchange. It can isolate each side of faulty sections automatically so it can keep power supply on the remained healthy sections of the feeders as seen in Figure 2.6

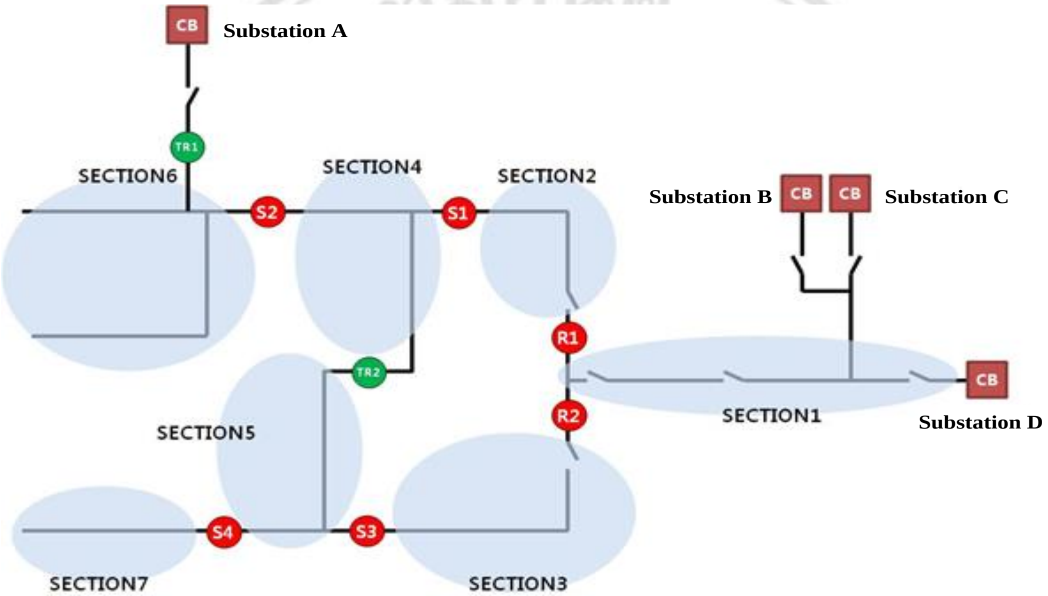

Figure 2.6 Conceptual diagram of system installation.

2.6.1 Switching optimization or reconfiguration

One of the effective ways for increased reliability is to change the feeder configuration by switching devices, called switching optimization. This is the most cost effective countermeasure for increased reliability because it only needs to relocate the existing switching device or install new one to the adequately position. The cost of switching device is relatively low compared with re-conductor or new feeder installation, even if it requires several new devices. Automated feeder switches are becoming key components in electric distribution systems. These devices can be opened or closed in response to sensing a fault condition, or by receiving control signals from other locations, as seen in Figures 2.10(A) and 2.10(B). They show how this can be accomplished.

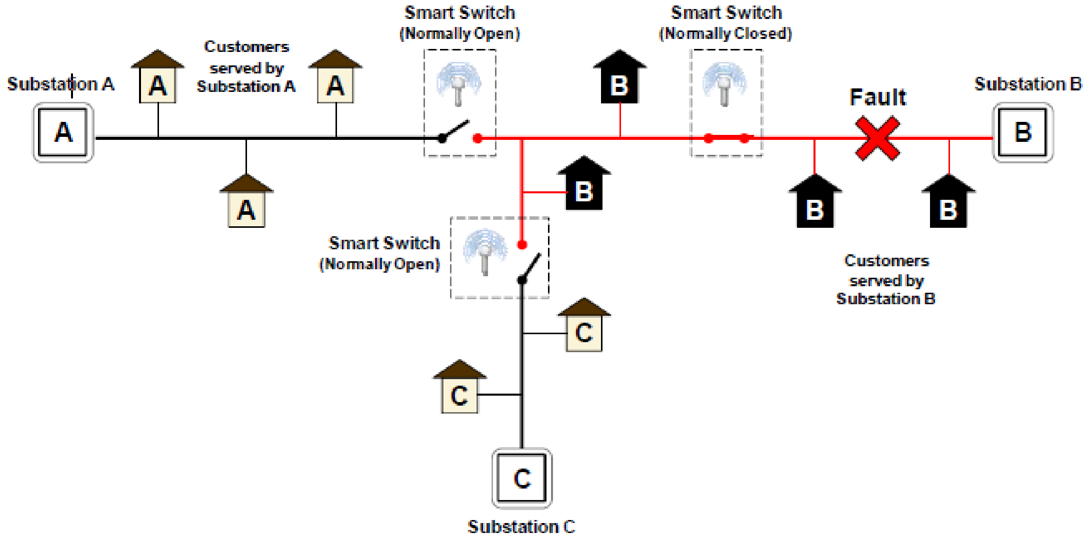

Figure 2.7 (A): Configuration of Feeder before Switching.

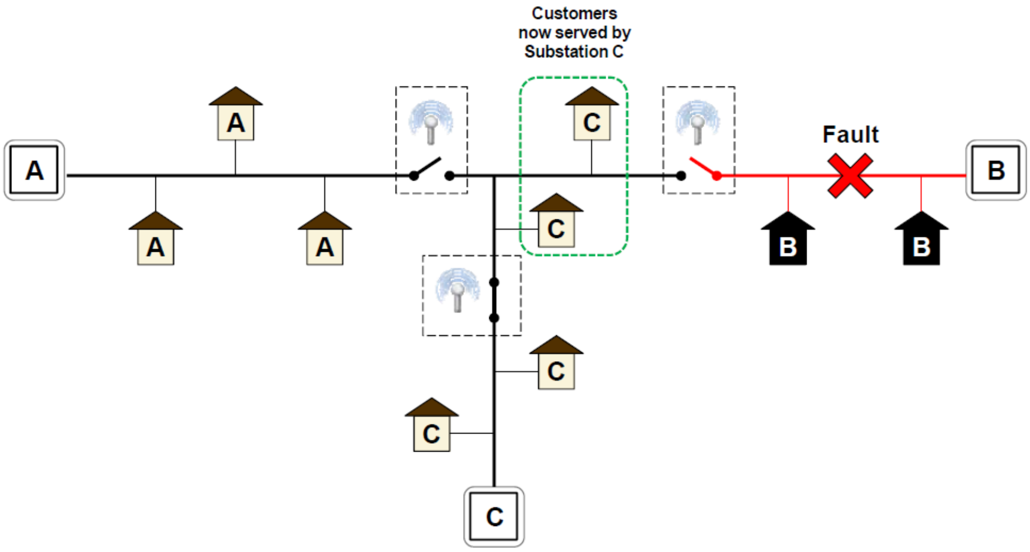

Figure 2.7 (B) Configuration of Feeder after Switching.

Switching optimization searches for the best configuration of the feeders based on the outage of customer reduction by conducting one by one switching operation. The optimum system outage of customer reduction compared to the original system. In the optimum system, the location of switching device is changed to substation A side and load is transferred from substation A to B. This load becomes far from a substation in comparison with the original system and the power from substation B increases, so that losses on feeder B would increase. However, the current of the load passes, thick conductor from substation B, and the loads on feeder A become adequate size considering the conductor size, which means that total outage of customer reduce on feeder A and B would decrease. The total loads on the feeder A and B to switching optimizes the reliability, but the overload of substation should be noted.

- Detection of outages at distribution transformers or other common points of failure can improve response times and reduce restoration costs. This is especially valuable in remote areas where the crew would normally have to spend a significant amount of time patrolling the grid to find the exact fault location.

- Call center: A customer calling the utilities to report an outage is still the main input for outage solutions in the database.

- Data Information: is a process of data collection by IT (Information Technology) system. In case of outage in the distribution customers will call to call center, then data will be entered and recorded in the system on problem occurred and problem solving duration for better service on solving outage. Thus, the IT system is necessary for this approach.

2.7 Economic analysis

In order to develop and support the increasing demand and reduce the loss of the system, it is important to evaluate the cost of alternatives including investment costs, maintenance costs and cost of loss in the system during the period of analysis. After evaluation of the expenditure, it is important to develop, plan and assist the enhancement of society. The approaches to determining the Economic Internal Rates of Return (EIRR), Net present value and Benefit cost ratios (B/C ratios) of the project are applied suitably [18].

2.7.1 Net Present Value

$$NPV = \sum_{t=1}^{n} \frac{B_t}{(1+i)^t} - \left[\sum_{t=1}^{n} \frac{C_t}{(1+i)^t} + C_0 \right] \tag{5}$$

where: B_t = Returns of project occurred in the year t.

C_t = Costs in year t.

C_0 = Cost of first year.

i = Discount rate or interest rate.

t = Year of project implementation is from years 1, 2, 3…….n

n = Life of the project.

2.7.2 Internal Rate of Return (IRR)

$$IRR = \sum_{t=0}^{n} \frac{(B_t - C_t)}{(1+r)^t} - \left(\sum_{t=1}^{n} \frac{C_t}{(1+r)^t} + C_0 \right) = 0 \qquad (6)$$

where:

B_t = Returns of the project occurred in the year t.

C_t = Costs in year t.

C_0 = Cost of first year.

t = year of project implementation is from years 1, 2, 3…….n

n = life of the project.

r = Internal rate of return, but the internal rate of return (IRR) uses a discount rate that makes the net present value of all cash flows from a particular project equal to zero.

2.7.3 Benefit Cost Ratio (B/C ratio)

$$B/C(\text{ratio}) = \frac{\sum_{t=1}^{n} \frac{B_t}{(1+i)^t}}{\sum_{t=1}^{n} \frac{C_t}{(1+i)^t} + C_0} \qquad (7)$$

where: B_t = Returns of the project occurred in the year t.

C_t = Costs in year t.

C_0 = Cost of first year.

i = Discount rate or interest rate.

t = Year of project implementation is from years 1, 2, 3…….n

n = Life of the project.