ECONOMIC EVALUATION OF FEEDER AUTOMATION IN A DISTRIBUTION SYSTEM

by

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ABSTRACT

The absence of economic justification is one of the leading barriers for the integration of feeder automation systems into distribution networks. These systems may require substantial capital investments from utilities, but the benefits obtained from them, mainly enhanced service reliability, could outweigh the costs of the associated equipment. Utilities, aware of the economic impact that service reliability has on distribution networks and its customers, are incorporating the monetary value that customers place on service reliability into economic evaluations to justify feeder automation investments. This project presents a reliability economic analysis method that can be used to evaluate the integration of feeder automation devices into Puerto Rico's distribution system. The application of this method is demonstrated using data from a hypothetical distribution feeder and the proposed installation of four automatic sectionalizing switches. Project costs, quantifiable reliability benefits, and benefit-cost ratio calculations are presented. Also, the effect of parameter changes on the benefit-cost ratio is evaluated. The results show that the installation of the automatic devices is justified as the economic life, feeder failure rate, average load, and energy cost increase on the feeder under study.

RESUMEN

Uno de los mayores obstáculos para la integración de sistemas de automatización en alimentadores de distribución es la ausencia de una justificación económica. Estos sistemas de automatización pueden requerir inversiones de capital considerables por parte de las compañías de electricidad, pero los beneficios que se pueden obtener de ellos, principalmente las mejoras en la confiabilidad del servicio, pueden superar los costos asociados a esta tecnología. Las compañías de electricidad, conscientes del impacto económico que tiene la confiabilidad del servicio en las redes de distribución y en sus clientes, están incluyendo el valor monetario que los clientes le asignan a la confiabilidad del servicio en sus evaluaciones económicas para justificar las inversiones en la automatización de alimentadores. Este proyecto presenta un método para realizar análisis económicos que consideren la confiabilidad del servicio eléctrico y que se puede aplicar para evaluar la integración de equipos de automatización en alimentadores del sistema de distribución de Puerto Rico. La aplicación de este método se presenta utilizando datos de un alimentador de distribución hipotético y la instalación propuesta de cuatro seccionalizadores automáticos. Los costos del proyecto, los beneficios cuantificables relacionados con la confiabilidad del servicio y los cómputos de la relación beneficio-costo también se presentan. Además, se evalúa el efecto de cambios en varios parámetros sobre la relación beneficio-costo. Los resultados muestran que la instalación de los equipos automáticos se justifica a medida que aumenta la vida útil del proyecto, la razón de averías, la carga promedio y el costo de la energía en el alimentador bajo estudio.

To my family . . .

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List of Abbreviations

AUB	Athens Utilities Board
CIC	Customer Interruption Costs
DA	Distribution Automation
FA	Feeder Automation
FDIR	Feeder Detection, Isolation and Service Restoration
LBNL	Lawrence Berkeley National Laboratory
OC	Outage Cost
O&M	Operation and Maintenance
PRAM	Predictive Reliability Assessment Model
PW	Present Worth
RR	Utility Reduced Energy Revenues
RTU	Remote Terminal Unit
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCADA	Supervisory Control and Data Acquisition

List of Symbols

C	Percentage of commercial load
EL	Economic life
F_{Switch}	Manual switch failure rate
g	Uniform rate
i	Interest rate
I	Percentage of industrial load
$IC(t)$	Customer outage costs
Ka	Energy cost
l	Feeder length
L	Average feeder load
λ	Average feeder failure rate
LD	Load density
LR	Labor rate
$Load_{Total}$	Total feeder load
n	Number of automatic devices
P/A	Present value given an annuity
P_{Time}	Patrol time
R	Percentage of residential load
RT_{Line}	Failure repair time
RT_{Switch}	Manual switch repair time
tf	Average restoration time of electrical service from other feeders
tr	Average fault repair time
tss	Average restoration time of electrical service from substation
T_{Sw}	Time to isolate failure and close tie switches
UE	Un-served energy due to power outages
V	Vehicle cost rate
X	Desired section length

1 INTRODUCTION

1.1 Justification

Automation of distribution networks has become a normal practice around the world. Technology advances in this area have allowed utilities to simplify system operations, reduce outage response and restoration times, and obtain improved system efficiencies. Also, residential, commercial, and industrial customers experience enhanced service reliability thanks to the integration of automation equipment into distribution networks. The overall benefits from these systems are numerous, but the investments in this technology could also be significant and cannot be made indiscriminately. Utilities, aware of the importance of providing reliable service to customers and considering their own budget constraints, are incorporating service reliability into economic analysis evaluations to justify investments on feeder automation equipment.

This project presents examples of economic analysis techniques used by different utilities to cope with feeder automation integration. Since the primary benefits from this technology are improved service reliability and reduced utility revenue losses, these variables are included in recent economic analysis evaluations. The results from these evaluations are used to compare different feeder automation projects to select the most economically justifiable ones for system integration.

The economic analysis techniques used by these utilities can be applied to Puerto Rico's distribution system. Our work presents a reliability economic analysis method that can be used to evaluate feeder automation projects integration into our distribution system. The method will allow engineers and managers to economically justify automation devices installations along distribution feeders. Also, it will allow them to consider feeder length, loads, failure rates, and number of automatic devices into the economic justification process.

1.2 Objectives

The main objective of this project is to present a reliability economic analysis method that can be used to justify the integration of feeder automation projects into Puerto Rico's distribution system. The specific objectives of our work include:

- Study the main components of feeder automation systems.
- Study different economic analysis methods used by utilities to justify distribution automation projects.
- Study the integration of service reliability equations into the economic analysis.
- Demonstrate the application of the reliability economic analysis method in a distribution feeder automation project.

1.3 Summary of following chapters

General background information on feeder automation devices, specifically line reclosers and sectionalizing switches, is presented in Chapter 2. A basic economic analysis procedure and examples of economic evaluations performed by different utilities on distribution automation projects are discussed in Chapter 3. Also, this chapter includes information on the monetary value that customers place on service reliability, also known as customer outage costs, and formulas for quantifying reliability benefits. Chapter 4 presents the application of the reliability economic analysis on a distribution feeder. Project costs, reliability benefits, benefit-cost ratio calculations, and the effect of parameter changes on the economic evaluation are also included. Conclusions and recommendations for future work are presented in Chapter 5.

2 FEEDER AUTOMATION WITH LINE RECLOSERS AND SECTIONALIZERS

The IEEE defines distribution automation (DA) as systems that enable an electric utility to monitor, coordinate, and operate distribution network components in real-time mode from remote control centers [1]. These systems integrate automatic equipment to simplify the distribution system operations, reduce operational costs, improve service reliability, and enhance system efficiencies. Examples of circuit components used in DA systems include automated capacitor banks, circuit breakers, regulators, switches, and line reclosers. From these, automatic switches and line reclosers are used extensively in feeder automation (FA) to improve service reliability and reduce the repair times after power outages.

Automatic line reclosers are devices that have the capability of sensing circuit overcurrents and interrupting fault currents at predetermined time intervals [2]. Also, these circuit devices can restore the electric service automatically by reclosing their contacts after momentary outages [3]. On the other hand, automatic switches or sectionalizers are circuit opening devices that de-energize the downstream circuit after a predetermined number of successive current impulses. They operate while the circuit is de-energized by upstream circuit breakers or reclosers, since most of these devices do not have interrupting capability.

Automatic reclosers and sectionalizers provide enhanced reliability to customers by reducing the outage times and the number of clients without electric service at the occurrence of system faults. These equipment, when properly coordinated with other protective devices, can dissipate the electric arc created by temporary faults or isolate the areas affected by permanent faults. Their coordinated operations can avoid disruptions of the electric services provided to commercial and residential customers, thus maintaining high reliability indices [4]. Also, they can minimize the negative effects of power outages on these customers, including halt in business operations, equipment malfunctions, economic losses, etc.

These automatic equipment also improve the operational flexibility of electric utilities. Their use in distribution feeders allow utilities to identify permanent system faults, sectionalize the affected areas, reduce the repair times, and keep as many customers with continuous electric service as possible [5]. Also, the feeder can be normalized with minimal complications after repairing the fault conditions. This can be done either manually, remotely through a Supervisory Control and Data Acquisition (SCADA) signal, or automatically.

New technology improvements have increased the use of these distribution automation devices for fault isolation and load transfers [6]. Automatic loop sectionalizing schemes, which include the use of reclosers and switches with micro-processor based controls, allow the isolation of faults and the automatic transfer of unaffected portions of a distribution feeder to adjacent feeders. The configurations used in these schemes include two or more automatic line reclosers (where one or more can be substituted with switches) between two or more feeders interconnected by normally-open tie reclosers. At the occurrence of a permanent fault, these equipment reconfigure automatically to isolate the fault and minimize the customers affected by it.

Utilities around the world are implementing automatic loop sectionalizing schemes to their distribution feeders. Dominion, an investor-owned utility in the United States, implemented five-recloser loop sectionalizing schemes in its distribution feeders [7]. Figure 2.1 shows an example of the configuration used.

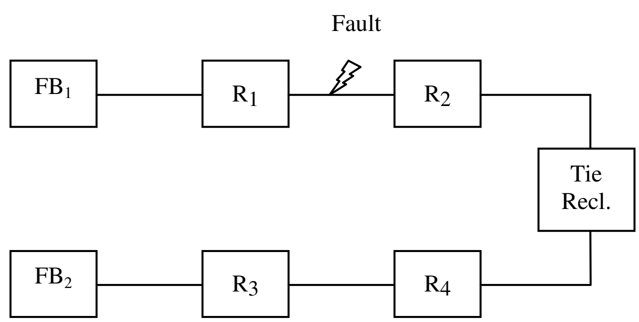

Figure 2.1 Five-recloser loop sectionalizing scheme at Dominion

In their application two distribution feeders, FB_1 and FB_2, were interconnected through a normally-open tie recloser. Also, each feeder had two normally-closed reclosers (R_1 and R_2 for feeder 1; R_3 and R_4 for feeder 2) and digital controls were used inside each unit. If, for example, a permanent fault occurs between R_1 and R_2 in Figure 2.1, then R_1 goes through its reclosing operations sequence and eventually locks out. R_2 senses the absence of system voltage and, after a predetermined time delay, changes its protection settings. The tie recloser also senses the loss of system voltage from feeder 1, but it closes as programmed and allows fault current to flow from feeder 2 up to the fault location. At this point R_2, if properly coordinated with other protective devices, will open its contacts instantly and lockout to isolate the fault. All of these operations take place in a couple of minutes, allowing the automatic transfer of the loads between R_2 and the tie recloser to feeder 2 while improving the reliability indices of the system.

Similar configurations have been used by other electric utilities. In Brazil, utilities are implementing the loop sectionalizing scheme using a combination of sectionalizers and reclosers with dedicated communication between the units [8]. This configuration allows the automatic equipment to interact with one another to confirm, at all times, the status and load currents of each unit [9], [10]. The implementation of FA with communication between devices allows them to locate faults, determine if adjacent circuit sections or feeders can handle the load transfers, and which units should operate.

As can be seen, the benefits and flexibilities obtained from implementing automatic line reclosers and switches for FA are numerous. Yet these devices are expensive, and their implementation in a DA project must include an economic analysis that considers the overall benefits and costs of their integration into the distribution system.

3 ECONOMIC ANALYSIS IN THE DISTRIBUTION SYSTEM

Economic evaluations of DA systems are crucial for determining the viability of their implementation [11], [12]. The installation of these systems cannot be based solely on the operational flexibility they provide to utilities or the improved reliability of electrical service experienced by customers. These systems are expensive, and their implementation must consider the costs of the equipment, return on the investment, and operation and maintenance (O&M) expenses, just to name a few [13]. A considerable amount of documents have been written on the operational benefits of installing these automation systems, but only a few include the economic aspects or provide a method for their economic justification.

This chapter presents important information related to economic analysis, including benefits and costs quantifications, and customer outage costs considerations. Also, examples of economic evaluations performed by different utilities are presented.

3.1 Economic analysis considerations

Lack of economic justification is one of the leading barriers to implementing DA. The economic evaluation process of a DA system should incorporate the consumer's needs, the utility's limitations, the expected benefits, and the investment necessary to achieve those benefits in order to decide whether or not to proceed with the DA project. In any case, the overall benefits should outweigh the investment on the project. The best prospects for expecting net benefits from DA are utilities which [14]:

- Have areas that require high service reliability;
- Have areas with diverse loads;
- Have areas with high energy losses;
- Have areas with significant voltage problems;
- Have many inaccessible meters; and
- Require additional generation, transmission, or distribution facilities.

The benefits of a DA project can be divided in two categories: quantifiable and unquantifiable. Quantifiable benefits are those that can be assigned a monetary value. They include reduced O&M costs, deferred capital investments, and increased revenues. Unquantifiable benefits, on the other hand, cannot be assigned direct dollar values and are difficult to incorporate in economic analyses. Examples include improved public safety, customer satisfaction, public image, and better information for engineering and planning. Most evaluations of DA implementation incorporate quantifiable benefits in the analysis, as these can be directly compared with the monetary costs of a project. Yet intangible benefits are given their due attention, especially when the quantifiable benefits and costs are almost equal and the unquantifiable benefits can help to justify the project.

These benefits must be considered in the different categories that comprise DA, namely: substation automation, FA, and consumer automation. Substation automation includes supervisory control of circuit breakers, load tap changers, regulators, and substation capacitor banks. Its potential benefits include:

1. Deferred Capital Expenditures – it is achieved through more efficient use of substation facilities. If real time data is made available through automation, for

example, then overloading of substation transformers can be avoided and voltage/VAR profiles can be improved.

2. Reduced O&M Costs – typically result from the reduced time required to operate substation equipment. Also, include savings from data collection and analysis due to reduced personnel's substation visits.
3. Consumer Savings – customer outage costs can be greatly reduced if the restoration times after power outages are improved. At present, the value that consumers place on reduced outage times is becoming critical for utilities and is included as part of the economic evaluation.
4. Improved Consumer and Governmental Relations – installation of a DA system is evidence for regulatory and financing agencies that the utility has a program to improve service reliability.
5. Better Information for Planning and Engineering – the real-time data obtained from the automation can be used to more accurately plan future system configurations.

Feeder automation, on the other hand, includes data acquisition and supervisory control of line reclosers, regulators, capacitors, and sectionalizing switches. The benefits for this category include:

1. Deferred Capital Expenditures – remote monitoring and operation of the automated equipment can optimize the utilization of existing feeders and defer the construction of additional transmission or distribution facilities [15], [16].

2. Reduced O&M Costs – reduced costs in this area are obtained from the reduced times to locate and isolate faults, reconfigure the feeder, restore service, operate switches, and collect data.
3. Consumer Savings – customer outage costs can be greatly reduced if the restoration times after power outages are improved.
4. Improved Consumer and Governmental Relations – reducing the outage times will reduce the complaints from consumers [17].
5. Better information for Planning and Engineering – the real-time data simplifies operations and future system planning.

The third category, consumer automation, includes the ability to remotely read meters, program time-of-use meters, connect and disconnect devices, and control consumer loads. The most important benefits are:

1. Deferred Capital Expenditures – customer peak demand can be reduced through load management and time-of-use incentives, which can defer the construction of additional facilities.
2. Reduced O&M Costs – it can be achieved through reduced labor requirements for meter reading, reprogramming meters, service connects or disconnects, and processing of consumer claims.
3. Increased Revenues – continuous communication with the consumer meter can alert the utility if the meter is being tampered. This can reduce the electricity theft and revenue losses.

Once the benefits and costs of these categories are considered, along with the needs of the distribution system at hand, an economic analysis is performed. This analysis compares the present worth (PW) of costs and benefits throughout the expected useful life of the project [18]. The results of this evaluation will help to decide if the functions under consideration are economically justifiable or if modifications should be made [19], [20].

The basic procedure for a benefit-cost analysis of a DA project is [21]:

1. Calculate the dollar benefits that can be achieved by implementing the candidate DA functions.
2. Identify the new facilities (field equipment, communication facilities, etc.) that are needed to accomplish the candidate DA functions.
3. Determine the costs to purchase, install, operate, and maintain these facilities over the expected life of the DA system.
4. Compare the expected benefits and costs for each year of system operation.
5. Calculate the benefit-cost ratio, investment payback period, and other measures that indicate whether the investment makes sense from an economic standpoint.

Since a DA project can include any combination of DA functions, the benefit-cost evaluation will consider those functions that pertain to the specific project. For example, if a utility has a DA project that concentrates on FA, then the benefits and costs of the functions associated with FA will be evaluated in the benefit-cost analysis. The results of this analysis will indicate if the implementation of the FA functions on the distribution system under study is economically justifiable. Thus, the presented economic analysis procedure can be used to evaluate the economic viability of a DA project that includes any combination of automation functions.

3.1.1 Feeder detection, isolation and service restoration function

The feeder detection, isolation and service restoration (FDIR) function has been identified in many studies as the most beneficial function in FA. Its implementation has the benefits of shorter outage durations and reduced fault investigation times. When a permanent fault occurs on a feeder without FDIR, customers served by this feeder experience longer outage times due to the field crews traveling to the feeder location, patrolling the feeder to locate the problem, performing the manual switching operations to restore service to some customers, and making the necessary repairs.

Automatic sectionalizing switches and line reclosers, which are the main components of the FDIR function, can divide the feeder into a small faulted section and a healthy portion. Clients connected to the healthy portion of the feeder can have their service restored from the automated system via the normal source or through the backup (tied) sources. This can occur in a couple of minutes. Even though the clients in the faulted section will still experience a prolonged outage until repairs are finished, the outage time will be much shorter than if the system was not automated.

Even though improved reliability measured in minutes cannot be directly translated into dollar savings, the customer interruption costs (CIC) can be used to assign a dollar value to reliability. A simple formula used for calculating CIC savings based on the number of automated sectionalizing switches, System Average Interruption Duration Index (SAIDI), and average load per feeder is:

$$CIC\ savings\ \left(\frac{\$}{year}\right) = L * SAIDI * \left(\frac{n}{n+1}\right) * IC(t) \qquad \textbf{Equation 3.1}$$

In this equation, L represents the average feeder load in kW, n the number of automatic sectionalizing switches in the feeder under evaluation, and $IC(t)$ the approximate customer outage costs in dollars per kWh. The term $\frac{n}{n+1}$ represents the per unit reduction in outage time thanks to the remote line switches [22] and SAIDI is the sum of customer interruption durations divided by the total number of customers. A conservative customer outage cost value used by utilities in the United States is $10 per kWh. This value represents the average cost of un-served energy to customers due to an outage. It is based on the monetary value that customers place on service reliability. Values for the other parameters in Equation 3.1 are readily available from utilities' system data.

Another important benefit from implementing FDIR includes labor and vehicle cost savings. Unless a specific damage location is identified via an eyewitness report, field crews must patrol a significant portion of the feeder to identify the root cause of the outage in a non-automated feeder. FDIR narrows the possible location of the fault to the portion of the feeder between two sectionalizing switches, thus limiting the area and times required by field crews to locate the faulted section. Thus, the resulting benefit is reduced labor and vehicle usage expenses.

To determine the savings in fault investigation due to FDIR integration, the amount of patrol time without FDIR should be multiplied by the portion of the feeder that does not need to be patrolled. This yields the savings in minutes. Multiplying the total minutes by the hourly labor and vehicle usage rates will yield the dollar savings per fault event. If System Average Interruption Frequency Index (SAIFI) is incorporated, then the annual savings can be obtained. The following formula illustrates how to calculate the labor and vehicle savings:

$$Labor, vehicle\ savings \left(\frac{\$}{year}\right) = (LR + V) * SAIFI * \left(\frac{n}{n+1}\right) * P_{Time} \qquad \textbf{Equation 3.2}$$

In this equation, LR and V represent the labor and vehicle costs in dollars per hour, respectively. SAIFI is the total number of customer interruptions divided by the total number of customers served. Also, P_{Time} is the patrol time, in hours, before FDIR implementation.

The equations presented in this section can be used to estimate the CIC reductions and labor and vehicle savings thanks to the implementation of the FDIR function in a distribution feeder. An important parameter needed for the quantification of these benefits is the customer outage costs, which is explained in detail in the next section.

3.1.2 Customer outage costs

A clear understanding of the monetary value that customers place on service reliability is crucial for utilities. Commercial and industrial customers can experience high economic losses due to outages, while residential clients could have to deal with the inconveniences and hassles that service interruptions bring [23]. The effects of service reliability, particularly the economic considerations that it entails, have forced utilities to incorporate the customers' outage costs in their economic evaluations. These costs, which reflect the customers' value of electric service reliability, can be used by utilities to identify areas of interest in the grid where capital investments are needed.

A customer survey is a very useful approach to yield customer outage costs [24]. With this method customers in the residential, commercial, and industrial classes are asked to estimate the costs or losses they would incur due to power supply interruptions. The scenarios presented in these surveys include power outages of varying durations, frequencies, and occurring at different times of the day and year. The advantage of this method lies in the fact that the customers are probably in the best position to assess their own losses [25]. It has been demonstrated that this method can yield the most consistent set of customer outage costs [26].

Utilities around the world have performed researches to assess the value that customers put on service reliability. In the United States, a research performed by Lawrence Berkeley National Laboratory (LBNL) includes customer outage costs from surveys completed by residential, commercial, and industrial customers [27]. In its research, LBNL integrated the results from 24 studies conducted by eight utilities around the United States to obtain outage costs by customer class.

The studies examined as part of this research used a survey method in which customers responded to various hypothetical outage scenarios. Outage durations, season (winter, summer, fall), time of day (morning, afternoon, night), climate, advance notice of service interruption, and availability of a backup generator were varied in the different scenarios so that customers could inform their potential economic losses. Commercial and industrial customers calculated the estimated labor and production losses due to the different scenarios, while residential customers presented the amount of money they would be willing to pay in order to avoid the power outage presented in the particular scenario.

Unlike commercial and industrial customers, where much of the costs associated with an outage can be converted into an economic loss based on lost profits or costs, the costs of residential customers are more intangible. That is why residential clients were asked to inform how much they would pay to avoid an outage, rather than specific labor or material costs.

The data from these surveys was uniformed and presented in customer damage functions that express customer outage costs for a given outage scenario and customer class as a function of location, time of day, consumption, and business type. They are used to estimate the economic losses experienced by customers as a result of reliability problems. These values are expressed in dollars per event ($/event), dollars per unit of un-served energy ($/kWh), or dollars per annual peak demand ($/kW).

The customer outage costs for the different customer classes show interesting results. The large commercial and industrial customers reported losses that go from $12,944 per event for a one-minute interruption to $119,715 per event for a 4-hour interruption. On the other hand, the cost per peak demand ranged from $3 per kW for a voltage sag and up to $45 per kW for an 8-hour interruption. The results also showed that the pattern was, in general, for an increase in the outage costs as the duration of the outage was increased. Still, caution must be taken when handling the data since the customer outage cost values are not directly proportional to outage time increases. Also, the customer damage functions showed that the mining, construction, and manufacturing businesses experienced the highest customer outage costs.

The small commercial and industrial customers, represented in the surveys as loads of 1 MW of peak demand or less, reported losses that go from $203 per event for a voltage sag to $7,361 per event for an 8-hour interruption. On the other hand, the cost per peak demand ranged from \$1 per kW for a voltage sag to \$99 per kW for an 8-hour interruption. The results trend generally upward, with a few deviations as the outage time progresses. It is important to mention that the values presented in the surveys to the different scenarios can vary from one respondent to another based on the business' location, working hours, way to handle outages, etc. This will definitely affect the overall customer outage costs determined in researches. In this particular study, the customer damage functions showed that the manufacturing, construction, and finance businesses experienced the highest outage costs.

On the other hand, residential customers reported low costs or willingness-to-pay values in comparison with the other customer classes. This was expected since residential clients are more concerned with the inconveniences that service interruptions can cause rather than actual out-of-pocket expenses. The willingness to pay ranged from \$2.32 per event for a 10-second outage up to \$26.27 per event for a 12-hour interruption. The results follow an increasing trend as the outage time progresses, but not in a proportional manner. Also, the results show that the outage costs per event are higher on weekends than on weekdays (the opposite of commercial and industrial customers) and during the winter than summer time.

The data from customer outage cost evaluations, like the one performed by LBNL, can be used by utilities for planning purposes. Utilities have to consider the costs incurred by its customers and the amount of money they are willing to pay in order to evaluate capital investments that consider service reliability. A system cannot be overbuilt and designed for a higher standard of reliability than what consumers are willing to pay, nor under built to an extent of service reliability that consumers will not tolerate. There has to be a balance between both goals, and the best way to consider them is by incorporating customer outage costs in the utilities' economic evaluation process.

3.2 Reliability benefit-cost analysis

Utilities around the world, especially those in the deregulated market, are paying special attention to the services provided to residential, commercial and industrial clients. In the deregulated market, customers have the option of choosing the electric utility that will serve their power needs. As expected, customers will demand high reliability power services or they will shop for other utilities that can meet their expectations. Reliable power services are crucial for most commercial and industrial customers, as service interruptions can transform into economic losses and productivity reductions that could take them out of business [28]. For this reason, utilities are incorporating the customer value of reliability of electric services into their economic analyses.

The following sections present reliability economic analyses performed by different utilities. These analyses concentrate on the FDIR function, since it has been found by many utilities as one of the most beneficial functions in FA [29], [30].

3.2.1 The Tai-Chung DA Project

The Taiwan Power Company implemented a DA project in the Tai-Chung District in 2003. Its system consists of various substations, feeders, automatic switches, capacitor banks, and loads capable of being remotely controlled. The DA system includes FA, distribution analysis, and customer management functions that allow the utility to monitor the system status, record system operation data, control devices, perform distribution analyses (load flow, short circuit, optimal switching, etc.), and monitor and collect customer data. All of these functions were implemented to improve the reliability of the electric service provided to customers and to reduce the operational, maintenance, and construction costs of the utility. Figure 3.1 shows a simplified version of the Tai-Chung DA system.

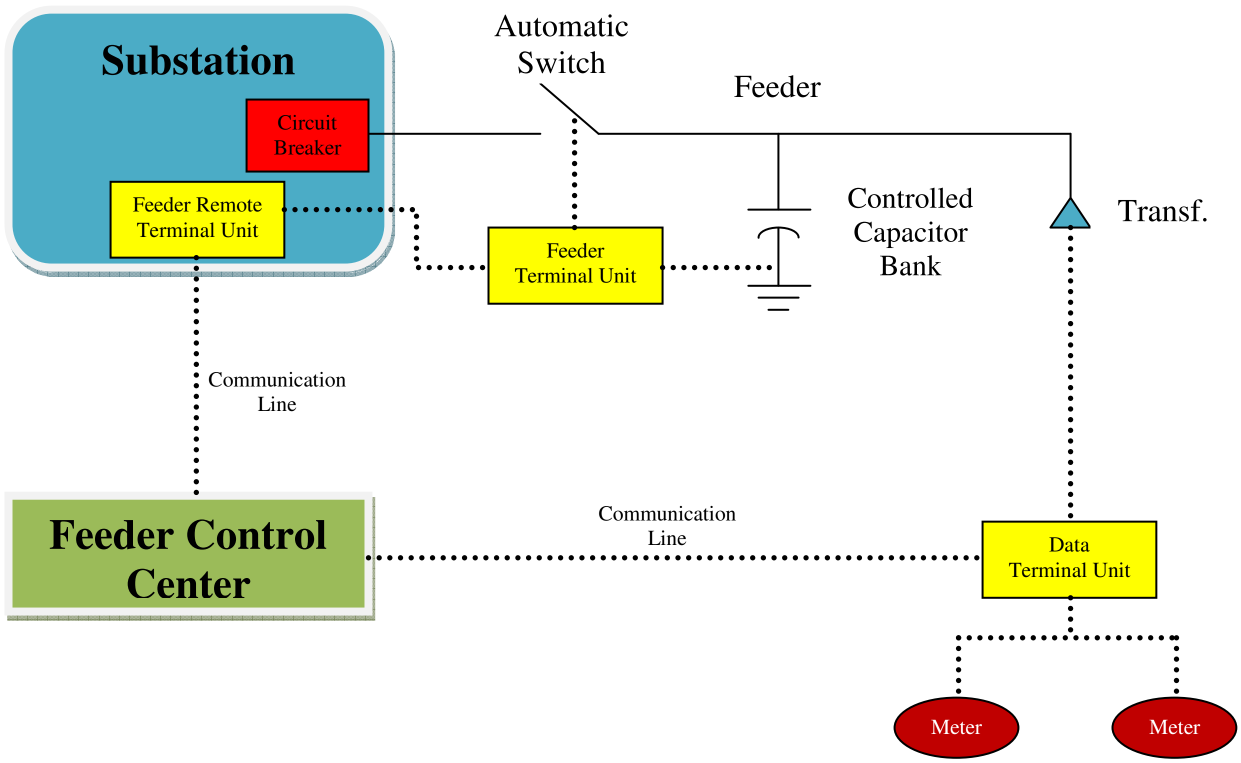

Figure 3.1 Structure of the Tai-Chung DA system

This system includes three main components: the feeder control center, on-site devices for controls and data acquisitions, and the communications system [31]. The feeder control center processes the real-time operating data and issues the necessary commands to control and coordinate the system operation through the on-site devices. These on-site devices, which include automatic switches, capacitors, and meters, send information to the control center about the status of the feeder and perform the actions ordered by the control center. This exchange of operational data and control actions occurs through the communications system, which allows the flow of information and action signals. This system includes feeder terminal units, data terminal units, telephone lines, coaxial cables, and fiber optic cables.

The DA system implemented by Taiwan Power Company required large capital investments. For this reason, and for future DA system expansions, an economic analysis was performed to quantify the costs of its installation and the economic benefits associated with its implementation. This evaluation included not only the capital investments and the O&M costs, but also the cost reductions obtained from the DA system implementation.

The evaluation permitted the identification of the DA functions that provided the maximum benefits after DA system implementation. After carefully studying the benefit-cost results, the FA category proved to be the most beneficial to their DA system. Specifically, the FDIR function accounted for almost all of the benefits obtained from the FA category.

The FDIR function includes, mainly, the use of automatic switches and reclosers to isolate faulted areas in feeders. Also, these devices can substantially reduce the restoration and repair times after outages, thus reducing the costs associated with power failures. Motivated by the results obtained in the benefit-cost study of the Tai-Chung DA project, the engineers responsible for the economic evaluation developed formulas to quantify the costs associated with power failures.

The two formulas used for quantifying the outage costs were CIC and utility reduced energy revenues (RR) [32]. These formulas integrate the effect of service reliability into the economic evaluation of DA systems.

The principal difference between the economic analysis method used by Taiwan Power Company and economic evaluations performed by other entities was the integration of the number of automatic switches in the outage cost quantification formulas. The use of automatic switches reduces outage durations and outage costs, since these circuit components sectionalize the faulted area of a feeder and maintain as many customers in service as possible. As a consequence, they minimize the lost energy revenues on the utility side. At the same time, their use will minimize the costs associated with lost production, production spoilage, and paid staff unable to work on the customer side. Thus, the incorporation of the number of switches in the outage cost quantification formulas is crucial for obtaining the reliability improvements of the FDIR function.

The CIC and RR formulas consider the quantifiable losses, customer types, feeder loads, feeder failure rate, number of switches, and the restoration and repair times of power outages. It is important to remember that these times will be reduced thanks to the use of the automatic switches. Equations 3.3 and 3.4 show the CIC and RR formulas, respectively. Table 3.1 presents a description for each of the terms included in these formulas.

$$CIC\left(\frac{\$}{year}\right) = \frac{\lambda * l * L}{n+1}[0.5 * n * IC(tss) + IC(tr) + 0.5 * n * IC(tf)] \qquad \textbf{Equation 3.3}$$

$$RR\left(\frac{\$}{year}\right) = \frac{Ka * \lambda * l * L}{n+1}[0.5 * n * tss + tr + 0.5 * n * tf] \qquad \textbf{Equation 3.4}$$

Table 3.1 CIC and RR parameters descriptions

Parameter	Units	Description
λ	$failures\ per\ mile\ per\ year$	Average feeder failure rate
l	$miles$	Feeder length
L	kW	Average feeder load
n	$no\ units$	Number of switches
$IC(tss)$	$\frac{\$}{kW}$	Customer interruption cost based on service restored from the substation
$IC(tr)$	$\frac{\$}{kW}$	Customer interruption cost based on fault repair time
$IC(tf)$	$\frac{\$}{kW}$	Customer interruption cost based on service restored from other feeders
Ka	$\frac{\$}{kWh}$	Energy cost
tss	$minutes$	Average restoration time of electrical service from the substation
tr	$minutes$	Average fault repair time
tf	$minutes$	Average restoration time of electrical service from other feeders

Since loads vary during a day and network topology can also change due to restoration or maintenance work, average values are used for some of the parameters presented. Average values are implemented in the CIC and RR formulas for feeder failure rate, load, and restoration and repair times to better reflect the behavior of the feeder during a year. Studies like [33] use a dynamic approach to consider the variations in these parameters. This method is more time consuming and requires the use of computer software for the CIC and RR calculations.

Since faults can occur in any moment regardless of the feeder configuration, using average yearly values simplifies the evaluation and normalizes the data. Also, this historical average data can be used to predict future feeder behavior, thus permitting the computation of future CIC and RR values. With this information, the annual expected values of utility energy revenue losses and customer interruption costs before and after DA can be calculated.

Comparing the CIC and RR values before and after installing the automatic switches will reflect the reliability improvement benefits. These benefits can be obtained from the following equation:

$$Reliability\ Benefit\left(\frac{\$}{year}\right) = (CIC_{NA} - CIC_{A}) + (RR_{NA} - RR_{A}) \qquad \textbf{Equation 3.5}$$

This equation shows the reliability yearly benefits from installing the automatic switches in the distribution feeder. These benefits can be seen as part of the overall benefits of the FDIR function. This is very important, as the reliability benefits are only associated with the use of the automatic switches and are used to quantify the reliability improvements experienced throughout the system.

Based on the economical evaluation performed on the Tai-Chung District, where the PW of costs and benefits were compared, the total feeders' reliability improvement benefits accounted for over 95% of the overall benefits of the FDIR function.

3.2.2 Economic evaluation in an urban distribution system

An interesting evaluation approach to reliability economic analysis was performed in 2004, where a probabilistic benefit-cost analysis was completed in an urban distribution system [34]. In this study, the economic evaluation's main purpose was to find the optimum feeder section lengths, the feeder loading levels, and the distribution substation transformer loading levels that reduced the capital costs and increased the overall system reliability. Using mathematical models and simulations, it was possible to maximize the capital investments on the system improvements that would increase the distribution system's reliability level. Similar studies were presented in [35] and [36].

One of the most interesting aspects of the study was the use of equipment failure rates, repair and service restoration times, and CIC to obtain the optimum section lengths for a feeder. In this case, a section was defined as a three-phase conductor between two sectionalizing switches. Thus, optimizing the sections' lengths was equivalent to optimizing the number of switches along the distribution feeder. The following example can help to illustrate their approach.

Assume that loads are uniformly distributed along a three-phase feeder and that all the loads on the unaffected sections can be picked up once the failure is isolated (through the main feeder and/or through the tied feeders). Dividing a section of the feeder into two equally spaced sections by the installation of a sectionalizing switch (see Figure 3.2), and assuming a one-year payback period, the authors obtained the following benefit formula:

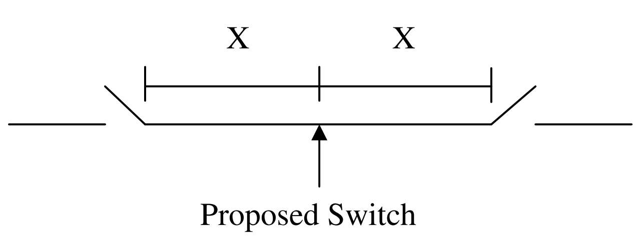

Figure 3.2 Dividing a feeder into equally-spaced sections

$$Benefit\ (\$) = (UE_{Old} - UE_{New}) * CIC \quad \textbf{Equation 3.6}$$

where

$$UE_{Old}\ (kWh) = (2 * X * \lambda)(2 * X * LD) * RT_{Line} \quad \textbf{Equation 3.7}$$

and

$$\begin{aligned} UE_{New}\ (kWh) = {} & (X * \lambda)(X * LD) * RT_{Line} + (X * \lambda)(X * LD) * T_{Sw} + \\ & (X * \lambda)(X * LD) * RT_{Line} + (X * \lambda)(X * LD) * T_{Sw} + \\ & (F_{Switch})(2 * X * LD) * RT_{Switch} + (F_{Switch})(Load_{Total}) * T_{Sw} \quad \textbf{Equation 3.8} \end{aligned}$$

These equations show that the total reliability benefit of the feeder, obtained from the installation of the sectionalizing switches, can be expressed in terms of the desired section length, X. The terms UE_{Old} and UE_{New} represent the un-served energy to customers due to power outages before and after the switch installation, respectively. As expected, the installation of the sectionalizing switch in the feeder section presented in Figure 3.2 will reduce the number of clients affected by power failures and, thus, the overall customer costs associated with power outages. The optimum section length can then be obtained by equating the reliability benefit equation to the capital and installation costs of the sectionalizing switch. Table 3.2 (see next page) details the terms included in the UE_{Old} and UE_{New} equations.

Table 3.2 Un-served energy parameters descriptions

Parameter	Units	Description
X	$miles$	Section length
UE	kWh	Un-served energy due to outage
λ	$failures\ per\ mile\ per\ year$	Feeder failure rate
RT_{Line}	hr	Failure repair time
F_{Switch}	$\frac{events}{year}$	Manual switch failure rate
RT_{Switch}	hr	Manual switch repair time
$Load_{Total}$	kW	Total feeder load
T_{Sw}	hr	Time to isolate failure and close tie switches
LD	$\frac{kW}{mile}$	Load density
CIC	$\frac{\$}{kWh}$	Average customer interruption cost

3.2.3 Athens Utilities Board DA project

Another interesting reliability study was performed on the Athens Utilities Board (AUB) distribution system. In their evaluation, reliability simulations were run with the computer software Predictive Reliability Assessment Model (PRAM) to quantify the effects of varying degrees of automated switching capability on the reliability of three AUB distribution feeders [37]. The reliability indices studied as part of the evaluation where SAIFI and SAIDI. The values obtained on these indices from varying the penetration of automatic switches were then used in the CIC computations. The results of these computations allowed comparisons on the economic benefits and incremental costs from implementing varying degrees of switching automation.

The first part of the study consisted on evaluating the changes of feeder failure rates and operating times of switches (from manual to automatic switching) on the reliability indices SAIFI and SAIDI. The results showed that SAIFI decreased as the feeder failure rate was lowered, but remained unchanged due to operating time changes in switching operations. This was expected, as SAIFI is a measure of the number of outages and is not affected by the penetration of automation equipment. On the other hand, SAIDI decreased as the switching times and the feeder failure rates decreased. The results showed that SAIDI improved as additional automation was added, but the benefits from automatic switches integration tended to flatten when enough automation was implemented. These results suggest that a point of diminishing returns may be reached on distribution feeders where adding more automated switching capability provides little or no benefit.

The second part of the evaluation on the AUB feeders incorporated the reliability indices results into the CIC calculations for the benefit-cost analysis. In this case, since the SAIDI values from different degrees of automation integration were obtained from simulations that included feeder failure rates and switching times, a simple formula was used for the CIC calculations. The formula used was:

$$CIC\left(\frac{\$}{year}\right) = IC(t) * SAIDI * L \qquad \textbf{Equation 3.9}$$

In this equation, $IC(t)$ is the outage cost, in dollars per kWh, and L is the average load, in kW. The number of automatic switches is not included in this formula, since the SAIDI values obtained from the simulations in the first part of the study included the effect of these equipment on the system. After completing the CIC calculations and performing the reliability benefit-cost analysis, they found that the integration of automatic switches and reclosers in the feeders were fully justified by the avoided customer outage costs. Also, they found that as more automatic devices were incorporated into the feeders the incremental benefits diminished. Similar results were obtained in [38]. Reliability studies performed by other utilities [39] show similar results when using computer software for reliability indices computations in the benefit-cost evaluations.

The economic analysis studies presented in this Chapter show different approaches to quantify the reliability benefits of the FDIR function. In general, the reliability benefits can be quantified by comparing the CIC and RR values before and after FDIR implementation. Also, the labor and maintenance cost reductions obtained from the automatic devices installations can be incorporated into the overall benefits of the FDIR function. These quantifiable benefits allow the incorporation of service reliability into the economic analysis evaluation process so that FA projects can be economically justified.

The background from the reliability economic studies presented in this section can be used to analyze FDIR implementation in Puerto Rico's distribution system. A method for reliability economic analysis of FA in a hypothetical distribution feeder is presented in the next chapter.

4 RELIABILITY ECONOMIC ANALYSIS ON A DISTRIBUTION FEEDER

4.1 Introduction

The integration of FA through the installation of automatic switches and reclosers must include an economic analysis as part of the evaluation. The costs associated with these equipment and the potential benefits from their installations must be weighed in order to decide if their implementation is economically justifiable. This analysis should also incorporate the reliability of service as part of the equations, especially when it is the main concern of the customers connected to the distribution system under study.

This chapter presents a method for performing a reliability economic analysis on a distribution feeder. This method, as will be discussed in the following sections, can be used to economically evaluate the integration of FA through automatic sectionalizing switches and reclosers in Puerto Rico's distribution system. To demonstrate the procedure, a hypothetical feeder is presented along with distribution system data, customer outage costs information, and economic analysis parameters. The analysis considers the installation of automatic switches along the feeder, but it can be extended to the integration of automatic line reclosers. The procedure includes the calculation of the project costs, the quantifiable benefits, and the benefit-cost ratio. Also, it provides a means for analyzing the effect of parameter changes in the benefit-cost analysis results.

4.2 Method

The procedure used in our economic analysis was as follows:

1. Collect the network data. Even though our study used example data to demonstrate the reliability economic analysis method, the collection of system data is necessary for any economic evaluation. The data used in our study included the length, failure rate, load, energy cost, and load distribution of the example feeder. Also, the customer outage costs per customer class were used in the evaluation. These values are indispensable for any economic analysis that incorporates the reliability of service since it allow the quantification of the costs and benefits associated with FA implementation.
2. Determine the costs associated with the FA project under consideration. In our study, automatic switches were implemented in the hypothetical distribution feeder. The overall costs included the purchase and installation of the automatic switches, plus the associated yearly maintenance costs. Other FA equipment, like substation communications equipment and SCADA related systems, were not considered. Even though the costs of these systems can be included in the economic analysis study, these systems were considered already in service and their costs were not included in our evaluation.
3. Estimate the monetary benefits associated with the installation of the automatic devices. The overall benefits included CIC, RR, and O&M cost reductions. The main objective was the calculation of the reliability benefits from automatic switches installations.

4. Calculate the PW of the costs and benefits of the project [40].
5. Calculate the benefit-cost ratio in order to find out if the installations of the automatic equipment are economically justified. Benefit-cost ratios greater than one indicate viable installations based on quantifiable (tangible) parameters.
6. If necessary, perform a sensitivity analysis to evaluate how changes in different parameters affect the benefit-cost ratio. This step is useful when the calculated benefit-cost ratio is less than one, intangible benefits cannot justify the installations, and the project needs to be re-evaluated. Even though the benefit-cost ratio in our project was greater than 1, this step was performed to demonstrate its importance in economic analysis studies.

As we mentioned earlier, this method can be used by engineers and managers in Puerto Rico as an additional tool in the justification process of FA projects. With this method, the integration of automation devices into the distribution network will not be based solely on the expected reliability indices improvements, but on quantifiable monetary values. This tool will help them to economically justify the installation of sectionalizing switches and line reclosers around the island, and re-evaluate or discard FA projects that are not economically viable.

A flowchart is the best way to visualize the different steps of the reliability economic analysis method presented. Figure 4.1 shows a flowchart with the different steps needed to complete the process.

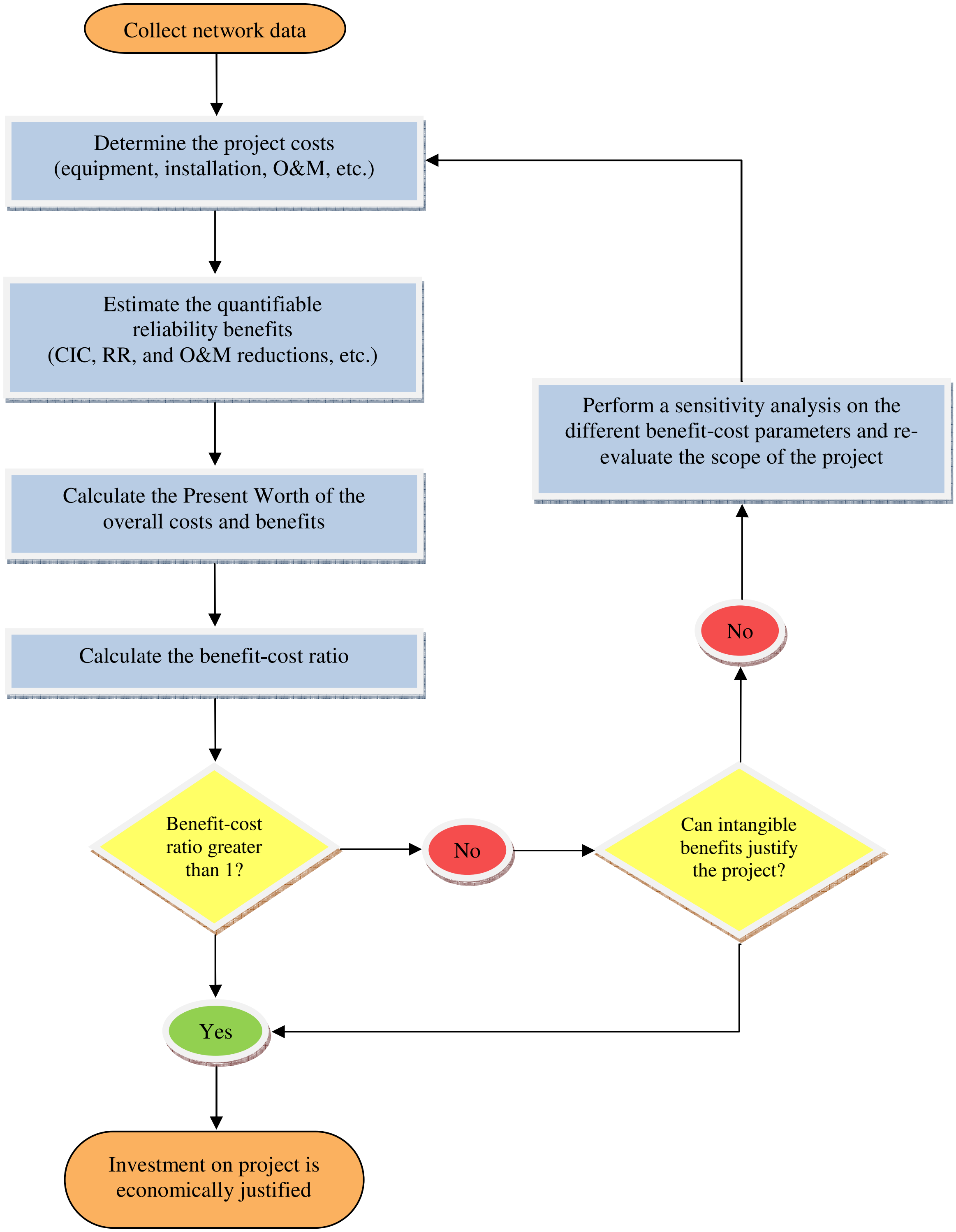

Figure 4.1 Reliability economic analysis flowchart

4.3 Benefit-cost analysis on a distribution feeder

The distribution feeder used in our evaluation consisted of four manual switches, 6,000 kW of average load, and it was 4.5 miles long. The manual switches and the loads were evenly distributed along the feeder in order to be able to use the previously presented CIC and RR formulas. Also, the loads on the taps off the main feeder were assigned back to the main trunk, so that all loads were distributed along the main feeder. These assumptions were made to simplify the model under study and should not affect the overall results of our evaluation.

The distribution feeder was mainly residential, with a load distribution of 65 percent residential, 30 percent commercial, and 5 percent industrial. Also, the average feeder failure rate was 0.795 failures per mile per year and the average energy cost was estimated at $0.15 per kWh. All of the values presented thus far could be obtained from the operational and historical databases available at utilities. Table 4.1 shows part of the feeder data used in our evaluation.

Table 4.1 Example feeder data

Parameter	Value	Description
λ	$0.795\ failures\ per\ mile\ per\ year$	Average feeder failure rate
l	$4.5\ miles$	Feeder length
L	$6{,}000\ kW$	Average feeder load
n	4	Number of switches
Ka	$0.15\ \frac{\$}{kWh}$	Energy cost
R	0.65	Percentage of residential load
C	0.30	Percentage of commercial load
I	0.05	Percentage of industrial load

The main objective of our study was to perform a benefit-cost analysis on this feeder to demonstrate the reliability economic analysis method, the importance of the values obtained in each step of the process, and its applicability to any FA project. In our example feeder, the evaluation concentrated on the substitution of the four manual switches by automatic switches. As stated in Chapter 3, the installation of automatic switches has the effect of reducing the average times for detection, isolation, and service restoration after power outages. For this reason, the times associated with these operations are crucial for any economic analysis that considers reliability of service as part of the evaluation.

The average times for feeder restoration from substation, from other feeders, and for fault repair for the base case (using the manual switches for field operations) can be obtained from the historical data of the utility under study. In our example, the average time for restoration from the substation was 5 minutes, from other feeders was 1 hour, and the fault repair took 1.75 hours, on average. The time for restoration from the substation was relatively short compared to the restoration from other feeders, since the feeder breaker was already automated.

On the other hand, after the installation of the automatic switches the expected average time for restoration from the substation was set to 5 minutes, from other feeders to 15 minutes, and the fault repair was reduced to 1 hour. These values could be estimated from the operating times of the automatic equipment and the reconfiguration process in the distribution system under study.

Another data necessary for the evaluation were the customer outage costs per customer class. This could be the most difficult data to obtain for any economic evaluation. As stated in Chapter 3, these values are collected from surveys where the customers are asked to place monetary values on service reliability. These values can vary from region to region, and utility to utility, as they are based on cost estimates that customers perform on the different scenarios included in the survey. Tables 4.2 and 4.3 present hypothetical customer outage costs, per customer class, based on the operating times set for the base case and for the circuit after the installation of the automatic switches, respectively. These are not actual values and are included only to demonstrate the economic analysis method.

Table 4.2 Customer outage costs – Base Case

Duration	Residential	Commercial	Industrial
$tss = 0.083\ hr$	$2\frac{\$}{kW}$	$15\frac{\$}{kW}$	$25\frac{\$}{kW}$
$tf = 1\ hr$	$4.50\frac{\$}{kW}$	$25\frac{\$}{kW}$	$40\frac{\$}{kW}$
$tr = 1.75\ hr$	$5\frac{\$}{kW}$	$27\frac{\$}{kW}$	$41\frac{\$}{kW}$

Table 4.3 Customer outage costs – After Automatic Switches Installations

Duration	Residential	Commercial	Industrial
$tss = 0.083\ hr$	$2\frac{\$}{kW}$	$15\frac{\$}{kW}$	$25\frac{\$}{kW}$
$tf = 0.25\ hr$	$3.50\frac{\$}{kW}$	$20\frac{\$}{kW}$	$35\frac{\$}{kW}$
$tr = 1\ hr$	$4.50\frac{\$}{kW}$	$25\frac{\$}{kW}$	$40\frac{\$}{kW}$

Finally, the cost per automatic switch installation, the yearly maintenance hours and hourly rate for field work, the interest rate, and the economic life were needed to complete the evaluation. The cost per automatic switch including the control unit, communications radio to transmit the information to the substation's remote terminal unit (RTU), and associated installation cost was $25,000. The estimated maintenance hours per equipment were set to 15 hours per year and the hourly rate per field operator was $25, increasing at 4 percent per year due to the current collective bargaining agreement. Also, the market interest rate was fixed at 7 percent per year and the economic life was equal to the useful life of the equipment, which was 25 years. The manual and automatic switches had zero salvage value after their removal from the distribution system.

4.3.1 Present worth of costs

The easiest task to perform in our evaluation was the calculation of the PW of costs. As stated previously, the costs of the project included the four automatic switches and the yearly maintenance associated with these devices. The costs of the automatic switches occurred only during the first year of the project (when they were installed) and were calculated using the following equation:

$$Equipment\ Costs\ (\$) = n * Cost\ per\ Automatic\ Switch \qquad \textbf{Equation 4.1}$$

$$Equipment\ Costs\ (\$) = 4 * 25{,}000 = 100{,}000$$

This value represented a one-time disbursement from the utility when the devices were installed. On the other hand, the maintenance costs associated with these equipment would continue for the 25 years of the useful life of the automatic switches. Also, there would be a 4 percent annual increase in the hourly rate for the field crew. If the field crew consists of four employees, the maintenance for the first year after the installations would be:

$$Maintenance\left(\frac{\$}{year}\right) = n * Crew * LR * Maint.Hours \qquad \textbf{Equation 4.2}$$

$$Maintenance\left(\frac{\$}{year}\right) = 4 * 4 * 25 * 15 = 6{,}000$$

Now that we have all the costs associated with the project, the final step of this section was to calculate the PW of these costs. Since the maintenance costs increased at a rate of 4 percent per year as indicated in the collective bargaining agreement, the geometric series present worth factor was needed to discount the maintenance costs for the 25 years of the useful life of the devices. This factor can be written as:

$$(P/A, g, i, EL) = \left[\frac{1-(1+g)^{EL} * (1+i)^{-EL})}{i-g}\right] \qquad \textbf{Equation 4.3}$$

where P/A means present value given an annuity, g is the uniform rate (in our evaluation it was equal to the 4 percent annual increase), i is the interest rate, and EL the economic life. Using Engineering Economic Analysis nomenclature, the PW of costs was calculated by:

$$PW_{Costs}\ (\$) = 100{,}000 + 6{,}000(P/A, g, i, EL) \qquad \textbf{Equation 4.4}$$

$$PW_{Costs}\ (\$) = 100{,}000 + 6{,}000(P/A, 0.04, 0.07, 25) = 201{,}764.37$$

This value represents the actual worth of the costs of the devices and the maintenance needed for the 25 years of the expected useful life of the example FA project. The important thing to note is that all the monetary disbursements, no matter in what year they occurred, were converted to their PW values. Most economic analysis methods use the PW of costs and benefits in their evaluations since it simplifies the computations and discounts the monetary disbursements throughout the evaluation's economic life. In our project, the PW of the costs ($201,764.37) was compared with the PW of the benefits to obtain the benefit-cost ratio. The procedure used for the calculation of the project's benefits will be discussed in the next section, but it is similar to the one presented here.

It is important to mention that other costs can be included in FA project evaluations. For example, if communications and SCADA systems were needed for the integration of the automatic devices in our example distribution feeder, then these costs had to be included in the evaluation. In this case, the cost of each system, the annual service maintenance, and any additional disbursements would be included and discounted for the 25 years of the economic life of the project to obtain the PW.

The procedure used for calculating the PW of the costs in our example distribution feeder is straightforward and applicable to any FA project, including prospect projects for Puerto Rico's distribution network. The next section of our work shows how to calculate the PW of the benefits of the example distribution feeder.

4.3.2 Present worth of benefits

A reliability economic analysis requires that the benefits obtained from the installation of automatic equipment be quantified and included in the evaluation. In our project, the overall benefits included the reliability improvements due to the four automatic switches installations and the reduced O&M costs associated with the fault repairs.

As described in Chapter 3, the reliability improvement benefits from installing sectionalizing switches and line reclosers in distribution feeders can be obtained from the CIC and RR formulas presented in Equations 3.3 through 3.5. These equations, derived by C. L. Su and J. H. Teng in [16], provide a means for assigning a monetary value to the benefits associated with automatic devices. In our example feeder, these equations were used to quantify the reliability benefits from the installation of the four automatic switches.

The CIC and RR values for the base case and for the circuit that substitutes the manual switches with the automatic devices were obtained as follows:

1. Base case

   The outage costs in Equation 3.3 were calculated using the load distribution presented in Table 4.1 and the outage costs per customer class included in Table 4.2. These values calculated as follows:

$$IC(tss)\left(\frac{\$}{kW}\right) = (0.65 * 2 + 0.30 * 15 + 0.05 * 25) = 7.05$$

$$IC(tf)\left(\frac{\$}{kW}\right) = (0.65 * 4.5 + 0.30 * 25 + 0.05 * 40) = 12.43$$

$$IC(tr)\left(\frac{\$}{kW}\right) = (0.65 * 5 + 0.30 * 27 + 0.05 * 41) = 13.40$$

   As can be seen, these outage cost values considered the percentage of residential, commercial, and industrial customers connected to the feeder under study. In this way, a more accurate representation of the outage costs was obtained.

   Incorporating these values and the restoration times of the base case into Equations 3.3 and 3.4, we obtained:

$$CIC\left(\frac{\$}{year}\right) = \frac{0.795 * 4.5 * 6{,}000}{4 + 1}[0.5 * 4 * 7.05 + 13.40 + 0.5 * 4 * 12.43] = 224{,}738.55$$

$$RR\left(\frac{\$}{year}\right) = \frac{0.15 * 0.795 * 4.5 * 6{,}000}{4+1}[0.5 * 4 * 0.083 + 1.75 + 0.5 * 4 * 1] = 2{,}521.71$$

These values represent the yearly reliability costs before FA. The CIC result shows the economic losses of the customers connected to the feeder due to the service reliability level before FA. These costs may include production spoilage, paid staff unable to work, etc. Thanks to the outage costs per customer class presented in Table 4.2, it was possible to assign a monetary value to service reliability and its integration into the economic analysis process. In our example, the value obtained ($224,738.55) quantifies how much money the customers lost at the reliability level of the base case (using manual switches). In a similar manner, the calculated RR value ($2,521.71) quantified the yearly monetary losses experienced by the utility due to the un-served energy during power outages.

As demonstrated by the values obtained in this section, the transformation of service reliability into monetary values can be made through the CIC and RR formulas. These results, when compared with the reliability costs after FA, provided the reliability benefits from FA implementation. The quantification of the reliability costs for the example distribution feeder after automation follows.

2. Circuit after the installation of the automatic switches

Following the same procedure of the base case, the outage costs, CIC, and RR values were calculated. Using the load distribution in Table 4.1 and the outage costs data of Table 4.3, we obtained:

$$IC(tss)\left(\frac{\$}{kW}\right) = (0.65 * 2 + 0.30 * 15 + 0.05 * 25) = 7.05$$

$$IC(tf)\left(\frac{\$}{kW}\right) = (0.65 * 3.5 + 0.30 * 20 + 0.05 * 35) = 10.03$$

$$IC(tr)\left(\frac{\$}{kW}\right) = (0.65 * 4.5 + 0.30 * 25 + 0.05 * 40) = 12.43$$

$$CIC\left(\frac{\$}{year}\right) = \frac{0.795 * 4.5 * 6{,}000}{4+1}[0.5 * 4 * 7.05 + 12.43 + 0.5 * 4 * 10.03] = 199{,}946.48$$

$$RR\left(\frac{\$}{year}\right) = \frac{0.15 * 0.795 * 4.5 * 6{,}000}{4+1}[0.5 * 4 * 0.083 + 1 + 0.5 * 4 * 0.25] = 1{,}072.82$$

As expected, the yearly reliability costs were reduced after FA implementation. In Chapter 3, it was shown that the installation of automatic devices had the effect of reduced outage times, outage costs, and revenue losses. The results in our example feeder confirm this information, as the installation of the four automatic switches reduced the yearly reliability costs experienced by the customers and the utility.

Comparing the reliability costs before and after the installation of the automatic devices, we obtained the expected reliability benefits from FA implementation. This step is the focal point of our project, as it demonstrates that the benefits from service reliability can be quantified and included in economic analysis evaluations. The reliability benefits for our hypothetical distribution feeder were calculated using Equation 3.5 and the previous CIC and RR results. Its value was given by:

$$Reliability\ Benefit\left(\frac{\$}{year}\right) = (224{,}738.55 - 199{,}946.48) + (2{,}521.71 - 1{,}072.82) = 26{,}240.96$$

This result shows the yearly reliability benefits that could be expected from the installation of the four automatic switches in the example distribution feeder. This result would have a significant value for the engineers and managers responsible for economically justifying this project, as it allowed the quantification of the service reliability improvements and their integration into the economic analysis evaluation process.

The last parameter needed to obtain the overall benefits of implementing automation in our feeder was the reduced O&M costs associated with the fault repairs. Using the fault repair times in Tables 4.2 and 4.3, the following equation shows the O&M fault repair reductions:

$$Repair\ Reductions\ \left(\frac{\$}{year}\right) = (tr_{BaseCase} - tr_{Aut.}) * \lambda * l * Crew * LR \qquad \textbf{Equation 4.5}$$

$$Repair\ Reductions\ \left(\frac{\$}{year}\right) = (1.75 - 1) * 0.795 * 4.5 * 4 * 25 = 268.31$$

This value shows the fault repair benefits obtained from integrating the automatic switches into the example distribution feeder. Since the automatic devices reduced the fault repair times, this benefit was quantified through the presented formula. Also, it represents a yearly value, so the benefit would be expected to continue for the 25 year period of the project's useful life.

Finally, the PW of benefits was calculated using the annual reliability benefits and the O&M fault repair reductions. As mentioned in Section 4.3.1 of our work, the PW of costs and benefits are calculated to simplify the economic analysis evaluation and to discount the monetary disbursements through the economic life of the evaluation period. Using Engineering Economic Analysis nomenclature, the PW of benefits was calculated by:

$$PW_{Benefits}\ (\$) = 26{,}240.96(P/A, i, EL) + 268.31(P/A, g, i, EL) \qquad \textbf{Equation 4.6}$$

$$PW_{Benefits}\ (\$) = 26{,}240.96(P/A, 0.07{,}25) + 268.31(P/A, 0.04{,}0.07{,}25) = 310{,}352.01$$

This value ($310,352.01) represents the actual quantifiable benefits expected from the FA project implementation. It demonstrates that the benefits from FA projects can be quantified and incorporated into economic analysis evaluations. The use of the CIC and RR formulas were probably the most important variables in the benefits calculation, since they provided the means for quantifying the reliability of service and incorporating their worth into the economic analysis evaluation process. The final step to complete our economic evaluation process was the calculation of the benefit-cost ratio. This is presented in the next section.

4.3.3 Benefit-cost ratio

The benefit-cost ratio is obtained by calculating the equivalent worth of the benefits accrued through investment in a project divided by the equivalent worth of the costs of the project. The general rule is that when its value is greater than one, then the decision should be to invest. On the other hand, if it is less than one, then investing on the project should be avoided unless there are intangible benefits that can justify it. In our evaluation, the benefit-cost ratio was:

$$Benefit/Cost\ Ratio = \frac{PW_{Benefits}}{PW_{Costs}}$$ **Equation 4.7**

$$Benefit/Cost\ Ratio = \frac{310{,}352.01}{201{,}764.37} = 1.54$$

Based on this result, the decision to invest on the installations of the four automatic switches in the distribution feeder of our project would be justified. Considering the reliability of service and the price that customers put on this variable, this project was economically justifiable.

The results from reliability economic analysis evaluations, like the one presented in our work, are important from an economic and system planning standpoint. These results can give engineers and managers responsible for FA integration into distribution networks the tools to justify the investments based on quantifiable measures. The reliability economic analysis method presented in our work can be used as an additional tool in that justification process and, as demonstrated with its application on the hypothetical feeder, can be applied to any FA project. For this reason, we recommend its integration into the justification process of FA projects in Puerto Rico.

After completing the economic analysis evaluation in our example distribution feeder, we found:

- The PW costs of the project were $201,764.37. The calculation of this value was straightforward and included the equipment and maintenance costs.
- The PW benefits of the project were $310,352.01. This value was obtained from the reliability improvements and repair reduction costs obtained from the installation of the four automatic switches. The CIC and RR formulas were relevant to the calculation of the project's benefits, as they assigned a monetary value to service reliability.
- The benefit-cost ratio was 1.54. Since this value is greater than 1.0, then the investment on the installation of the automatic devices would be economically justified.

If the FA project at hand is not economically justified, based on the benefit-cost result, then a sensitivity analysis can be performed. This analysis is useful when parameter changes can help to justify the project or when engineers want to visualize how different parameters affect this ratio. For example, the reduction on the proposed amount of automatic devices can make a project that was originally economically unjustified into a viable one. Also, engineers can vary other parameters in order to have an idea of how these changes affect the benefit-cost ratio.

Even though the benefit-cost ratio of our example feeder was greater than 1, the following section presents a sensitivity analysis of different parameters on the benefit-cost ratio in order to demonstrate how this analysis can be performed.

4.3.4 Sensitivity of the benefit-cost ratio to parameter changes

Thus far, the values of the economic parameters and the feeder data were kept constant. But what happens when, for example, the number of automatic switches, feeder failure rate, economic life, average feeder load, market interest rate, and energy cost are altered in our reliability economic analysis? The effect of changing these individual parameters, while keeping the rest of the variables constant, was analyzed and the results are presented here in graphical form.

The number of automatic switches was the first parameter evaluated. The benefit-cost analysis of our study, which included the installation of the four automatic switches, gave us a 1.54 ratio. This value means that, based on the quantifiable benefits and costs of the project, the installations of the automatic devices were economically justified. Figure 4.2 shows how changes in the number of automatic switches, while keeping the other parameters constant, alter the benefit-cost ratio.

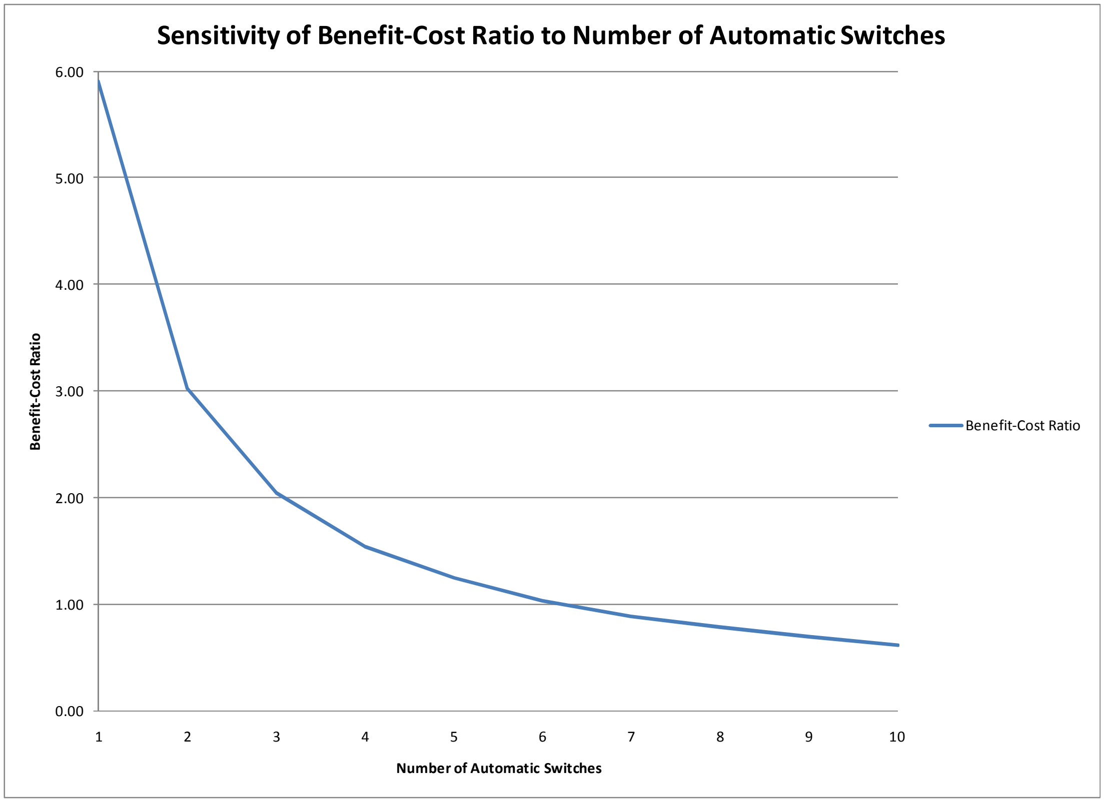

Figure 4.2 Effect of the number of automatic switches in the benefit-cost ratio

The graph shows that the benefit-cost ratio decreases as the number of automatic switches increases. At a low automation penetration level, the costs of the devices and associated maintenance are not significant enough to outweigh the project's benefits. But as the number of devices increases over six units, the overall costs exceed the obtainable net benefits and the project becomes unjustified from an economic standpoint. These results were expected from the CIC and RR equations, since the number of automatic switches was in the denominator of both equations. After completing the sensitivity analysis on this variable, the results demonstrated that increasing the quantity of devices in the example feeder had the effect of diminishing the benefits from their installations.

In our example, it would not be economically justified, based on tangible costs and benefits, to install seven or more equipment. The costs associated with these installations outweigh the possible benefits. Still, the installation of up to six devices is economically justified considering the effects on reducing the customer outage costs, increasing the utility revenues, and minimizing the costs associated with the fault repairs. The results from this analysis would be helpful for engineers evaluating the project, especially if the scope is altered and the number of automatic equipment is changed.

The next parameter change evaluated was the feeder failure rate. This parameter was included in the reliability benefit-cost analysis as part of the CIC and RR equations. The evaluation of changes to this parameter could be of importance to engineers evaluating the presented example feeder, especially if similar feeders that have the same load distributions, feeder extensions, and amount of connected loads are considered for FA implementation. The sensitivity of the benefit-cost analysis to failure rate changes could help them to decide which project should be integrated into the system.

Figure 4.3 presents a graph of the effect that feeder failure rate changes had on the benefit-cost ratio of the hypothetical distribution feeder. The graph shows that, while maintaining the rest of the parameters in the benefit-cost formulas constant, the benefit-cost ratio increased as the failure rate increased.

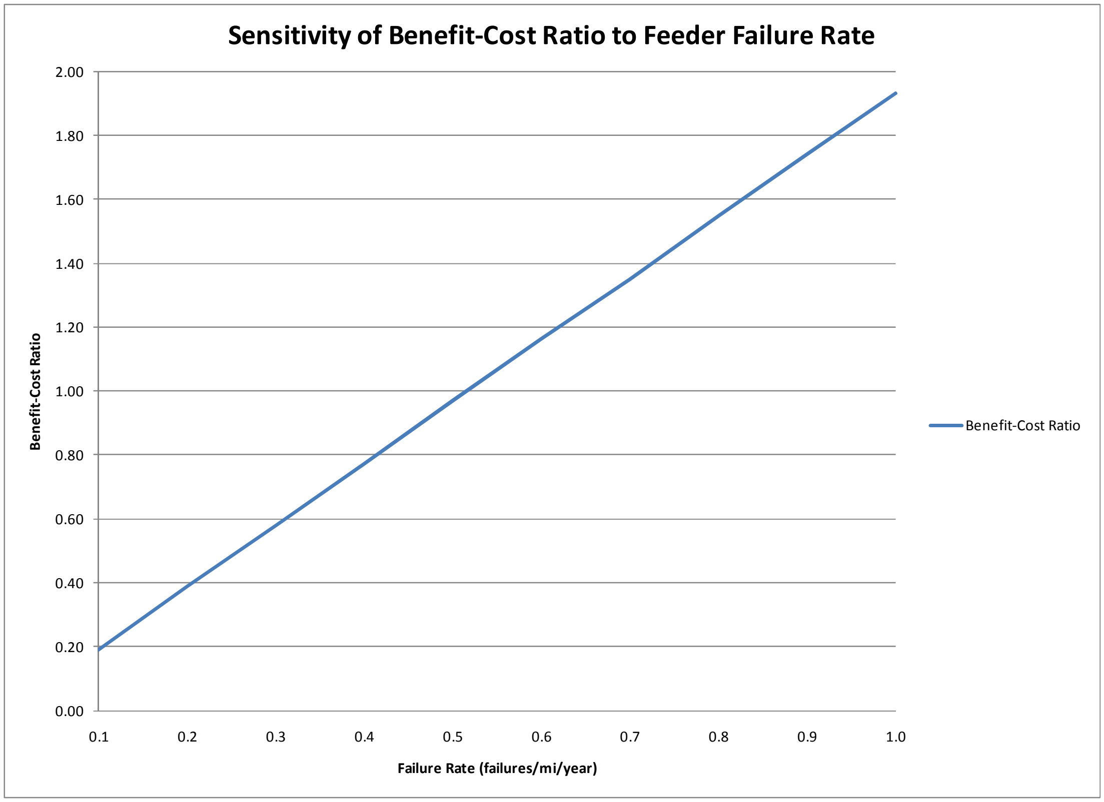

Figure 4.3 Effect of feeder failure rate in the benefit-cost ratio

Failures disrupt the continuity of electric service, thus affecting the utility revenues, the customers' outage costs, and the O&M costs associated with their repairs. Thus, the higher the frequency of outages in the feeder under study, then more economically justifiable is the feeder automation implementation. In our hypothetical feeder, this effect can be seen in Figure 4.3.

This graph shows that as the frequency of outages increases over, approximately, 0.55 failures per mile per year, the installations of the four automatic switches are economically justified. On the other hand, when just a few outages occur per year, the costs associated with the implementation of FA outweigh the possible benefits.

The results from this evaluation could be of importance to engineers if various feeders with characteristics similar to those of the hypothetical feeder are considered for FA implementation. For example, if similar feeders are being considered for the installation of four automatic switches, like in our example feeder, then the one with the highest failure rate should be chosen as demonstrated by the results in Figure 4.3.

The effect of the economic life was also evaluated in our study. Figure 4.4 presents a graph of the effect of this parameter on the benefit-cost ratio.

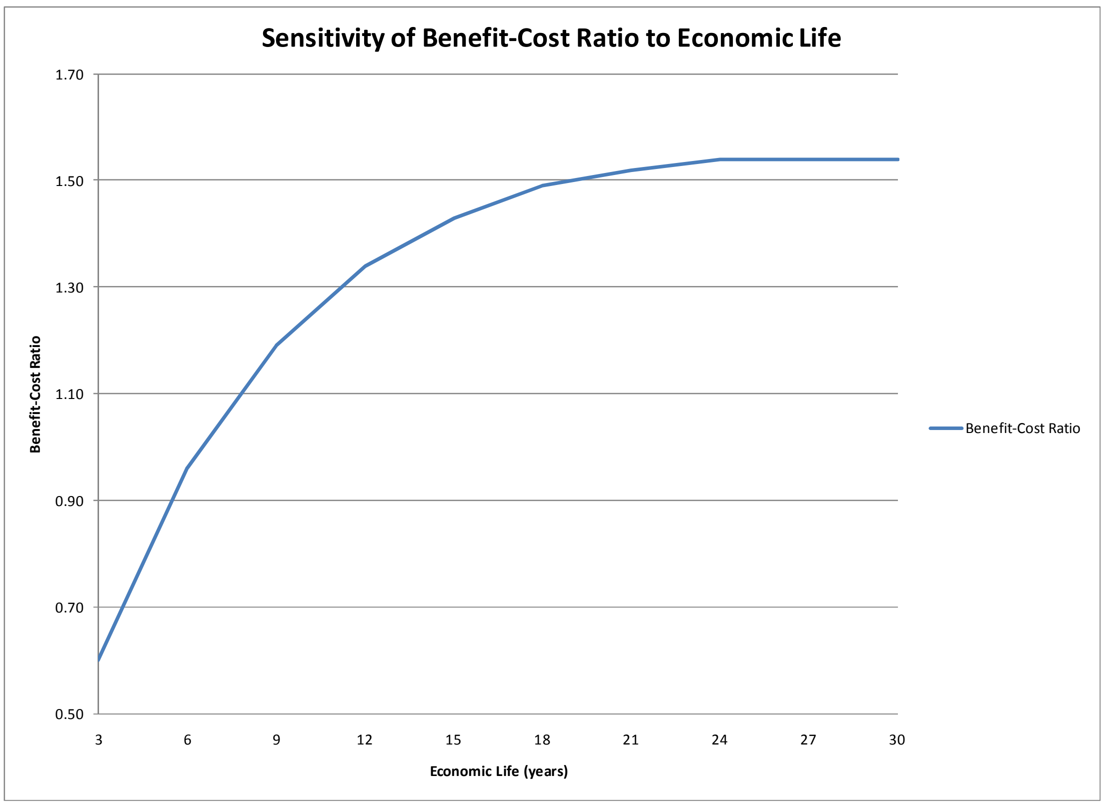

Figure 4.4 Effect of economic life in the benefit-cost ratio

This graph shows that increasing the economic life of the example feeder project had the effect of increasing the benefit-cost factor, but at a diminishing ratio. This behavior was expected from the maintenance costs of the automatic switches, where the geometric series present worth factor had its effect. Reviewing Equation 4.3, the economic life was raised to a negative exponential in this present worth factor and was responsible in part for the behavior of the benefit-cost ratio in the graph. Nonetheless, increasing the economic period increased the overall benefit-cost ratio up to 1.54 at 30 years.

The next parameter evaluated was the average load. This variable deals with the amount of load distributed along the feeder, including the residential, commercial, and industrial customers. Figure 4.5 presents the effect of this variable in the benefit-cost ratio.

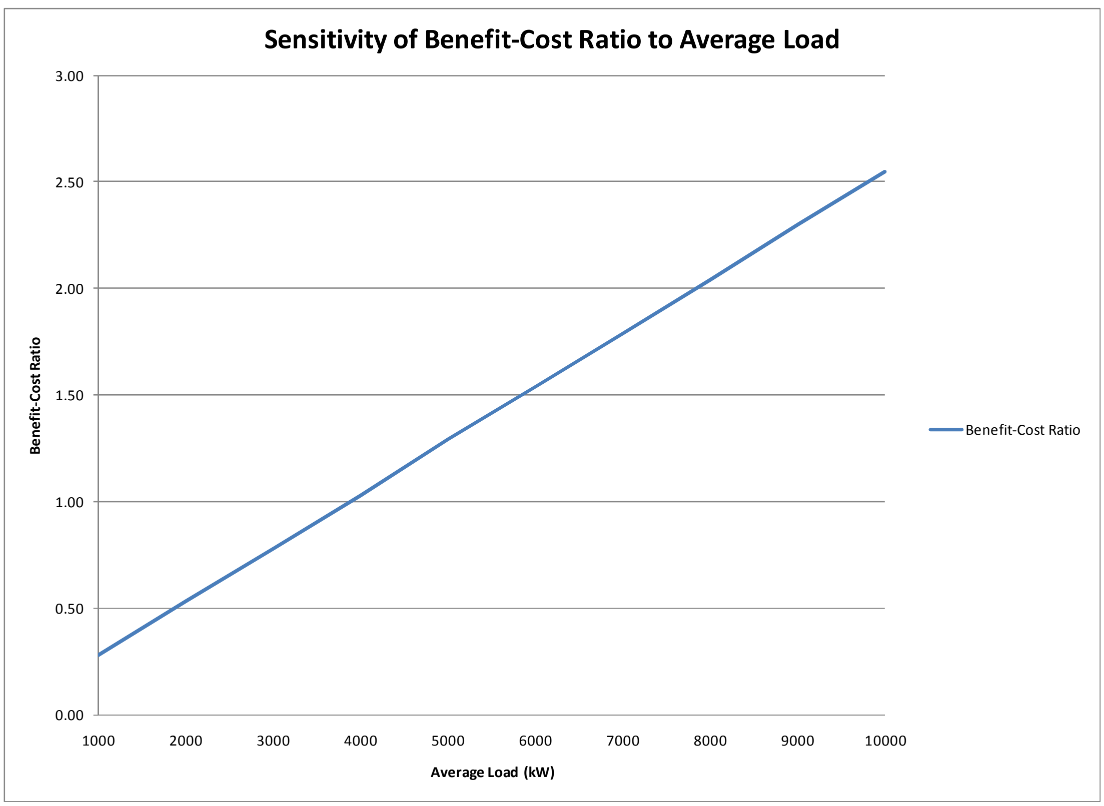

Figure 4.5 Effect of feeder average load in the benefit-cost ratio

The behavior of this graph is similar to the one presented for the feeder failure rate. As more loads are served by the feeder, increasing benefits can be obtained from the installation of the four automatic switches. The results also show that the installations are economically justified for feeder average loads exceeding 4,000 kW. For loads below this amount, only intangible benefits could justify the project.

The sensitivity of the benefit-cost ratio to market interest rate is presented in Figure 4.6. This graph shows that increasing the interest rate had the effect of reducing the benefit-cost ratio results.

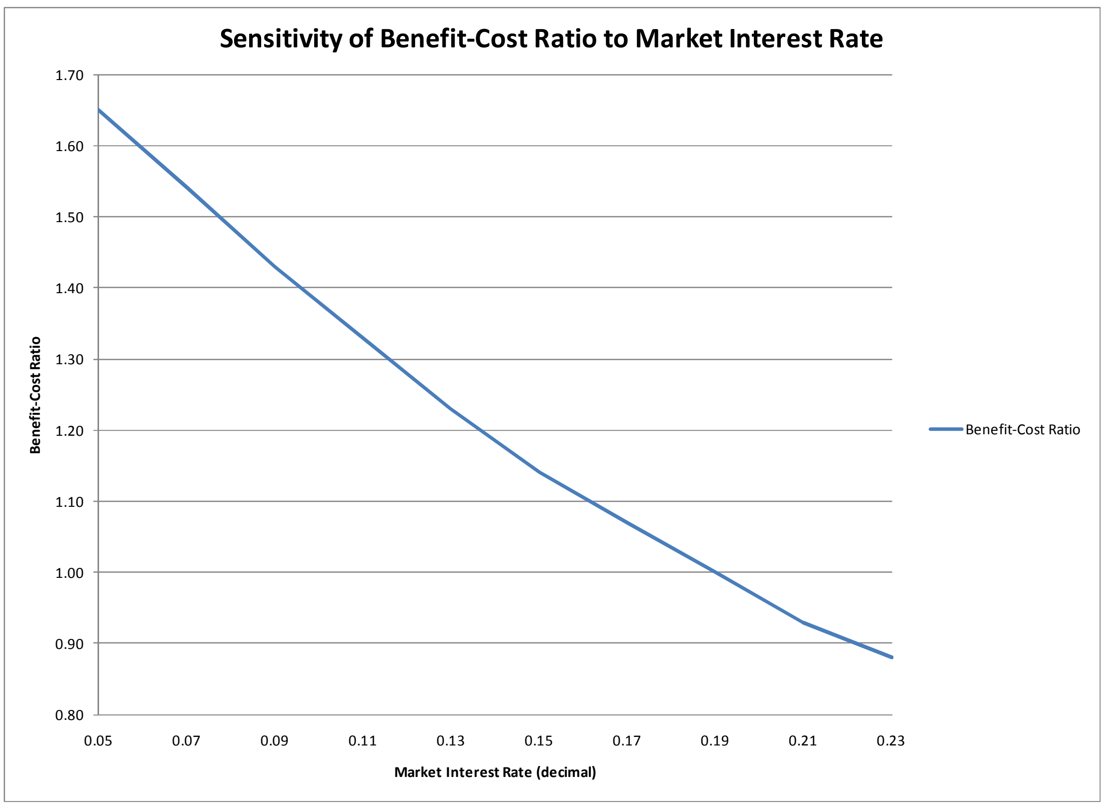

Figure 4.6 Effect of market interest rate in the benefit-cost ratio

The interest rate discounted the accrued benefits and costs through the project's economic life to obtain the PW value. As this rate increases, the costs of capital investments become higher and the net result is a reduction on the overall benefits of the FA project. In our evaluation, market interest rates beyond 19 percent make the project unjustified based on the benefit-cost ratio results.

The last parameter change analyzed was the average energy cost. This variable is related to the monetary charge per unit of energy in the distribution system under study. As indicated in Equation 3.4, this parameter was included in the economic evaluation process through the RR quantification formula. Figure 4.7 shows the effect of energy cost in the benefit-cost ratio.

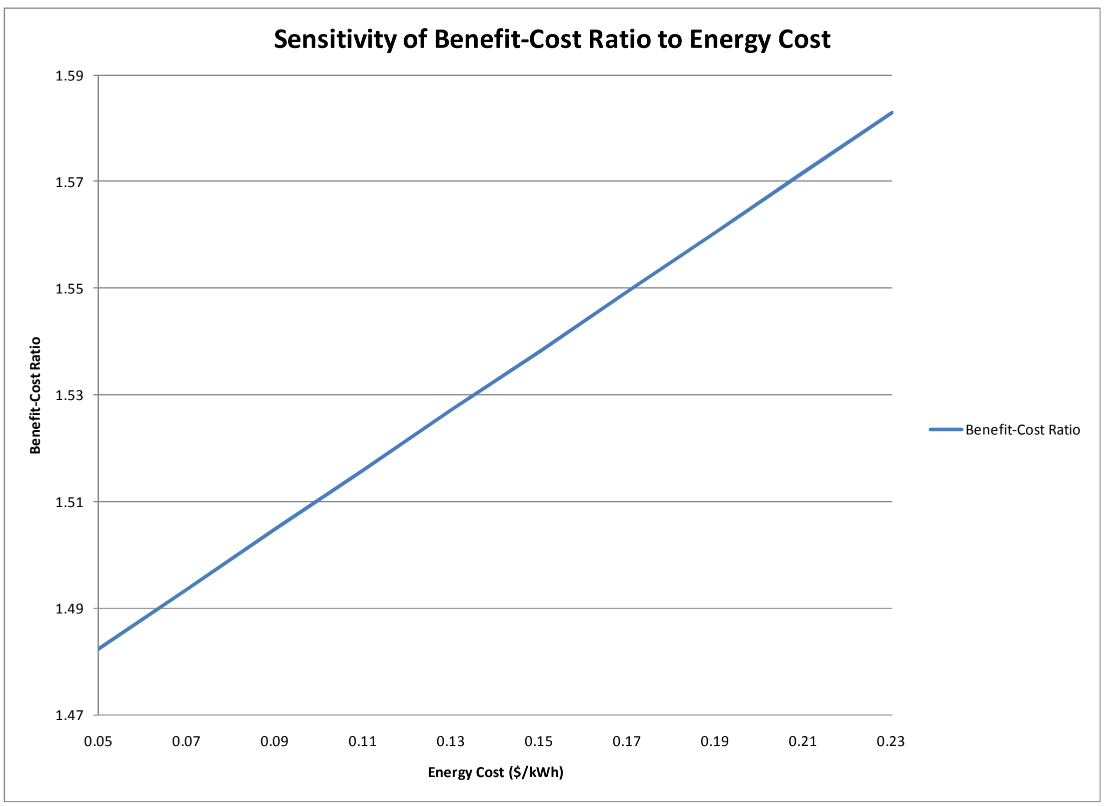

Figure 4.7 Effect of energy cost in the benefit-cost ratio

The graph shows that the benefit-cost ratio increases linearly as the energy cost increases. This result was expected since higher energy costs mean higher revenues from energy sold to customers. This is true if the other variables in the reliability benefit-cost analysis are kept constant.

As demonstrated in this section, the sensitivity of the benefit-cost ratio to parameter changes can be used in the evaluation of FA projects. This analysis is helpful when changes in the scope of the project at hand are needed or when similar candidate feeders are evaluated. Also, this analysis can give engineers an idea of how the ratio would behave due to parameter changes. In our example feeder, the sensitivity analysis showed that the benefit-cost ratio increased as the failure rate, economic life, average load, and energy cost increased, but was reduced when the penetration of automation and the market interest rate were increased.

5 CONCLUSIONS AND FUTURE WORK

5.1 Conclusions

This work presented different economic analysis techniques used by utilities to cope with FA projects justification. As indicated in the literature review, recent evaluations integrate quantifications of the worth of service reliability into the economic analysis. This has the advantage of considering the costs that reliability has on customers and utilities.

After completing this project we can establish the following conclusions:

- Utilities are integrating the worth of service reliability into economic analysis evaluations of FA projects. Quantification of service reliability must be included in the analysis. It can be obtained using the CIC and RR equations.
- Customer outage costs and outage times are crucial for CIC and RR calculations. These values allow the quantification of the potential benefits of the FDIR function, which includes the installation of automatic switches and reclosers.
- The reliability economic analysis method included in this work can be used as an additional tool in the evaluation process of FA projects integration into Puerto Rico's distribution system. Specifically, it will help engineers in the economic justification process of these projects. As demonstrated in our work, this method is straightforward and easy to complete.
- The reliability economic analysis method will also allow engineers and managers in Puerto Rico to determine the order of priority for feeder

automation expenditures based on feeder loads, failure rates, length, restoration times, and the number of proposed automatic equipment.

5.2 Future work

For future work the following are recommended:

- Include more data into the economic analysis. For example, other associated FA equipment like communications systems and components required to integrate the automatic devices into the SCADA system.
- Develop customer outage costs functions, in dollars per peak demand ($/kW), for the residential, commercial, and industrial customer classes of Puerto Rico. These values can be obtained through surveys that elicit responses regarding metrics like willingness-to-pay to avoid an outage, cost of lost sales, idle labor, equipment damages, etc.
- Use the reliability economic analysis method included in our work to compare different FA projects and degrees of automation penetration into the distribution system. The results from these analyses can be used to decide which projects should be implemented and the order of implementation.

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APPENDIX A DATA USED IN THE ECONOMIC EVALUATION

Table 1. Feeder and economic analysis data

Parameter	Value	Units
Λ	0.795	failures/mi/year
L	4.5	mi
L	6,000	kW
N	4	equipment
K_A	0.15	$/kWh
R	0.65	decimal
C	0.30	decimal
I	0.05	decimal
CS	25,000	$/equipment
MH	15	hr/equipment/year
Crew	4	employee
LR	25	$/hour/employee
I	0.07	decimal
G	0.04	decimal
EL	25	years

Table 2. Calculated customer outage costs

Calculated Customer Outage Costs - Based on Percentage of Load Type			
Customer Outage Costs ($/kW)	Rest. from Sub.	Rest. other Feeders	Fault Repair
Base Case	7.05	12.425	13.4
After Automation	7.05	10.025	12.425

APPENDIX B ECONOMIC EVALUATION RESULTS

Table 1. Costs calculations

Econ. Parameter	Value	Units
Equip. Costs	100,000.00	$
Maint. Costs	6,000.00	$/year
PW Costs	201,764.37	$

Table 2. Benefits calculations

Econ. Parameter	Value	Units
CIC Base Case	224,738.55	$/year
CIC After Automation	199,946.48	$/year
RR Base Case	2,521.71	$/year
RR After Automation	1,072.82	$/year
Reliability Benefit	26,240.96	$/year
Fault Repair Reductions	268.31	$/year
PW Benefits	310,352.01	$

Benefit-Cost Ratio: **1.54**