Integration of New Technologies into Existing Mature Process to Improve Efficiency and Reduce Energy Consumption

by

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A thesis
presented to the University of Waterloo
in fulfillment of the
thesis requirement for the degree of
Doctor of Philosophy
in
Chemical Engineering

Waterloo, Ontario, Canada, 2009

I hereby declare that I am the sole author of this thesis. This is a true copy of the thesis, including any required final revisions, as accepted by my examiners.

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Abstract

Optimal operation of plants is becoming more important due to increasing competition and small and changing profit margins for many products. One major reason has been the realization by industry that potentially large savings can be achieved by improving processes. Growth rates and profitability are much lower now, and international competition has increased greatly. The industry is faced with a need to manufacture quality products, while minimizing production costs and complying with a variety of safety and environmental regulations. As industry is confronted with the challenge of moving toward a clearer and more sustainable path of production, *new technologies* are needed to achieve industrial requirements.

In this research, a new methodology is proposed to integrate so-called *new technologies* into existing processes. Research shows that the *new technologies* must be carefully selected and adopted to match the complex requirements of an existing process. The new proposed methodology is based on four major steps. If the improvement in the process is not sufficient to meet business needs, *new technologies* can be considered. Application of a *new technology* is always perceived as a potential threat; therefore, financial risk assessment and reliability risk analysis help alleviate risk of investment.

An industrial case study from the literature was selected to implement and validate the new methodology. The case study is a planning problem to plan the layout or design of a fleet of generating stations owned and operated by the electric utility company, Ontario Power Generation (OPG).

The impact of *new technology* integration on the performance of a power grid consisting of a variety of power generation plants was evaluated. The reduction in carbon emissions is projected to be accomplished through a combination of fuel switching, fuel balancing and switching to *new technologies*: carbon capture and sequestration. The fuel-balancing technique is used to decrease carbon emissions by adjusting the operation of the fleet of existing electricity-generating stations; the technique of fuel-switching involves switching from carbon-intensive fuels to less carbon-intensive fuels, for instance, switching from coal to natural gas; carbon capture and sequestration are applied to meet carbon emission reduction requirements. Existing power plants with existing technologies consist of fossil fuel stations, nuclear stations, hydroelectric stations, wind power stations, pulverized coal stations and a natural gas combined cycle, while hypothesized power plants with *new technologies* include solar

stations, wind power stations, pulverized coal stations, a natural gas combined cycle and an integrated gasification combined cycle with and without capture and sequestration.

The proposed methodology includes financial risk management in the framework of a two stage stochastic programme for energy planning under uncertainty: demands and fuel price. A deterministic mixed integer linear programming formulation is extended to a two-stage stochastic programming model in order to take into account random parameters, which have discrete and finite probabilistic distributions. Thus, the expected value of the total costs of power generation is minimized, while the objective of carbon emission reduction is achieved. Furthermore, conditional value at risk (CVaR), a most preferable risk measure in the financial risk management, is incorporated within the framework of two-stage mixed integer programming. The mathematical formulation, which is called mean-risk model, is applied for the purpose of minimizing expected value.

The process is formulated as a mixed integer linear programming model, implemented in GAMS (General Algebraic Modeling System) and solved using the CPLEX algorithm, a commercial solver embedded in GAMS. The computational results demonstrate the effectiveness of the proposed new methodology.

The optimization model is applied to an existing Ontario Power Generation (OPG) fleet. Four planning scenarios are considered: a base load demand, a 1.0% growth rate in demand, a 5.0% growth rate in demand, a 10% growth rate in demand and a 20% growth rate in demand. A sensitivity analysis study is accomplished in order to investigate the effect of parameter uncertainties, such as uncertain factors on coal price and natural gas price.

The optimization results demonstrate how to achieve the carbon emission mitigation goal with and without *new technologies*, while minimizing costs affects the configuration of the OPG fleet in terms of generation mix, capacity mix and optimal configuration. The selected *new technologies* are assessed in order to determine the risks of investment.

Electricity costs with *new technologies* are lower than with the existing technologies. 60% CO_2 reduction can be achieved at 20% growth in base load demand with *new technologies*. The total cost of electricity increases as we increase CO_2 reduction or increase electricity demand. However, there is no significant change in CO_2 reduction cost when CO_2 reduction increases with *new technologies*. Total cost of electricity increases when fuel price increases. The total cost of electricity increases with financial risk management in order to lower the risk. Therefore, more electricity is produced for the industry to be on the safe side.

Acknowledgements

I would like to thank the following people who assisted me in my research:

- Professor Peter Douglas, University of Waterloo, for his encouragement and advice which were always welcome
- Professor Erik Ydstie, Carnegie Mellon University, for advice and assistance in Two-Stage Stochastic Programming and modeling
- Professor Ali Elkamal, University of Waterloo, for helping me in literature search and helping me in modeling
- Juan Du, Carnegie Mellon University, for helping me in Two-Stage Stochastic Programming and Financial Risk Management and modeling
- Dr. Dave McKeough, PPG Industries, for his assistance and support.
- Denise Callihan, PPG Industries, for helping me in literature search and finding appropriate books for this research

I would also like to thank my family who have supported and encouraged me throughout my studies.

Finally, I would like to thank my wife, Durriya, for her endless support and assistance over the last 8 years, without which I could not have achieved this work.

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Nomenclature

Subscripts
f: fossil fuel plants
j: raw materials, coal and natural gas, respectively
k: CO_2 capture procedure
p: new fossil fuel plants
rn: renewable energy plants
s: scenario
sq: sequestration procedure

Deterministic variables
E_f: electricity generation amount for fossil fuel plants
$Ek_{f, k, j}$: amount of electricity required for capture in fossil fuel plants
E_{nic}: electricity generation amount for IGCC station with capture
E_{nig}: electricity generation amount for IGCC station
E_{nnc}: electricity generation amount for NGCC station with capture
E_{nng}: electricity generation amount for NGCC station
E_{ns}: electricity generation amount for solar station
E_{nw}: electricity generation amount for wind station
E_p: electricity generation amount for new fossil fuel plants
E_{rn}: electricity generation amount for renewable energy plants
$X_{f, j}$: fossil fuel plants selection and fuel type decision
X_{rn}: renewable energy plants selection
X_p: new fossil fuel plants selection
X_{new}: new tech plants selection
$W_{f, sq}$: CO_2 sequestration procedure selection on fossil fuel plants
$W_{p, sq}$: CO_2 sequestration procedure selection on new fossil fuel plants
$Z_{f, j, k}$: CO_2 capture process selection on fossil fuel plants
$\gamma_{f, j, k}$: slack variables for carbon procedure of fossil fuel plants
$\varphi_{f, sq}$: slack variables for sequestration procedure of fossil fuel plants

Deterministic parameters
$A_{f:}$ amortized factor
Cap: capital investment cost for all power plants
Cc_f: CO_2 capture cost for fossil fuel plants
Ccs: capture cost for fossil fuel plants

$C_{f, j}$: CO_2 emission from fossil power plants per unit of electricity generated
C_{new}: CO_2 emission from new technology plants per unit of electricity
C_{now}: current amount of carbon emission in millions of tonnes per year
C_p: CO_2 emission from new fossil power plants per unit of electricity generated
Cre: CO_2 reduction target
C_{rn}: fixed capital cost for renewable energy plants
E_d: electricity demand
$Ereq_f$: electricity required for capture process on fossil fuel plants

F_{max}: maximum electricity generated in fossil fuel plants
F_{new}: fixed capital cost for new technology plants
F_p: fixed capital cost for new fossil fuel plants
Ge: electricity demand increase
HR_f: heat rate generation for fossil power plants
HR_p: heat rate generation for new fossil power plants
L_f: lower bound factor for electricity generation of fossil fuel plants
MaxC: maximum electricity requirement for capture process
O_f: operating cost for fossil power plants
O_{new}: operating cost for new tech station
O_p: operating cost for new fossil power plants
OpC: operating cost for all power plants
O_{rn}: operating cost for renewable energy plants
PerC: CO_2 capture factor
P_{max}: maximum electricity generated in new fossil power plants
Pr_j: price for raw materials, coal and natural gas
Retrofit: retrofit cost for existing fossil fuel plants
R_f: retrofit cost factor due to fuel switching for fossil fuel plants
RNmax: maximum electricity generated in renewable energy plants
Seq: sequestration cost for fossil fuel plants with capture
S_f: sequestration cost for fossil fuel plants
T: annual operating time

Stochastic Recourse Variables
z_s^+: electricity generation amount overproduced compared to stochastic demand
z_s^-: electricity generation amount under-produced compared to stochastic demand

Financial Risk variables
CVaR: the expected value of the costs in the 5 percent worst cases to be minimized
η_s: slack variable introduced for financial risk management

Stochastic parameters
c^+: fixed penalty cost per demand of under-production (shortfall) of electricity
c^-: fixed penalty cost per demand of overproduction (surplus) of electricity
$Demand_s$: demand for electricity generation per realization of Scenario *s*
$\mathrm{Pr}_{j,s}$: price of fuel type j per realization of Scenario *s*
p_s: probability of Scenario *s*

Abbreviations
A: Atitokan power plant
AIChE: American Institute of Chemical Engineers
Cap: capture
CCS: carbon capture and sequestration
CIM: current industrial methodology
CO_2: carbon dioxide
Coal-new: new coal plants

CostE: cost of electricity
CVaR: conditional value at risk
DOE: Department of Energy
DPC: design pinch calculations
D_{high}: high demand
D_{low}: low demand
D_{med}: medium demand
E: electricity generation
EHS: environmental health and safety
ExpC: expected cost
EVC: European Vinyl Corporation
FixC: fix cost
FRM: financial risk management
GAMS: General Algebraic Modeling System
HAD: hydrodealkylation of toluene to benzene
IGCC: integrated combine cycle
$IGCC_c$: integrated combined cycle with capture
ISO: independent system operator
KBR: Kellogg Brown Root
KWh: kilowatt hour
L: Lambton power plant
Ln: Lennox power plant
Lv: Lakeview power plant
MCEP: minimum capacity extended principle
MEMP: minimum equipment modified principle
MILP: mixed integer linear programming
Min Cost: minimum cost
MINLP: mixed integer non-linear programming
Mintot: minimum total cost
Min Tot Cost: minimum total cost
MV: mean value
MWh: megawatt hour
NGCC: natural gas combined cycle
$NGCC_c$: natural gas combined cycle with capture
N: Nanticoke power plant
NG: natural gas
NGCC-new: new natural gas plants
NPV: net present value
NT: *new technology*
OPC: operating cost
OPG: Ontario Power Generation
PA: pinch analysis
PC: pulverized coal
P&L: profit & loss
Pr_{high}: high price
Pr_{low}: low price

Pr_{med}: medium price
R/D: research & development
Ret: retrofit
ROI: return of investment
SBIR: small basic industrial research
Seq: sequestration
TB: Thunder Bay power plant
Tot CO_2: total carbon dioxide produced
Tot Cost: total cost
TotE: total electricity generation
TWh: trilllionwatt hour
UNFCC: United Nations Framework Convention on Climate Change
VaR: value at risk

1.0 Introduction

1.1 Background

Most businesses are confronting global competition, rapid changes in technology, environmental imperatives and complex source requirements. Many industries are now paying increasing attention to technology integration to maintaining profitability. As a result, development of a systematic methodology for technology integration is needed.

Although increased expected profit from integration of *new technology* is usually high, there is also financial risk when implementing *new technology*. The integration of *new technology* is sometimes far more complicated than a grass-roots design without using systematic methodology. It is important to identify the right or appropriate *new technology* in the process to be improved. *New technology* integration is an attractive framework for the holistic analysis of process improvement and the development of cost-effective and sustainable solution strategies.

The development of new integration methodologies is well-suited for a variety of small, medium and large industries. The application of integration methodologies to large industries often brings greater savings. However, it also requires greater capital cost.

Currently, industry is facing a number of important challenges, the most significant of which are:

- Energy costs and greenhouse gas emissions
- Labour costs
- Aging plants and infrastructure

1.2 *New Technologies*

New technologies for the purpose of this thesis are defined as: “processes, methods and tools that have not yet been used in the process under consideration”. For example, although depth of process control is commonly used in the oil refining industry, it is not commonly used in the pharmaceutical industry and therefore might be classified as a *new technology* in a pharmaceutical process. Although nuclear generating plants are commonplace in the electric generating industry, they are not commonly used in the chemical industry and therefore would be classified as *new technology* for a chemical process.

This work focuses on a systematic approach to integrate *new technology* into an existing process. Current methodologies focus only on state-of-the-art technology with little focus on financial risk. A study combining the process using available methodologies and a study of the technological development of the process and its financial risks allow the generation of a better solution. A new modified process results from the fusion of new and existing knowledge. Novel concepts or concepts novel to the process at hand can contribute to the development of new or modified processes that can be economically attractive. However, to be used effectively, these technologies or concepts must be carefully selected to match the requirements of the existing plant.

This research reports on the impact of integrating *new technology* on the performance of the plant process.

1.3 The Current Methodology

The so-called current methodology is based heavily on industrial experience, is not systematic and does not include financial risks associated with alternatives in order to support the decision. Figure 1.1 illustrates a simplified version of the existing methodology.

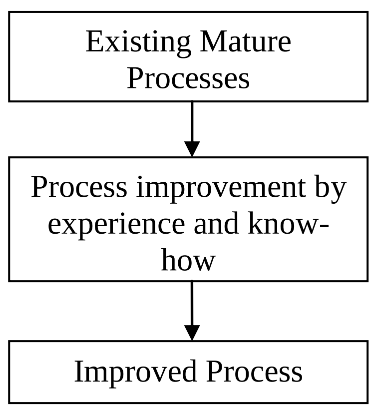


Figure 1.1 Current Methodology

The goal is generally accomplished by relying on experience to postulate a variety of configurations or alternatives that are then evaluated using a variety of techniques to determine their overall economic impact to the company. Although the use of experience here implies a current or an older technology, its impact cannot be overlooked. Employees with experience are extremely valuable and can often put forward a solution to a problem in a matter of minutes or even seconds that often proves to be close to optimal (Gladwell, 2007). Nevertheless, businesses are now running out of experienced engineers as well as confronting more and more complex problems that systematic methods are likely able to solve.

1.4 The New Methodology

A new methodology is proposed to obtain potential process improvement with the addition of so-called *new technologies* while minimizing financial risks. The overall methodology is based on the five steps shown in Figure 1.2; a detailed description of the steps is presented in Chapter 3. The first step is to improve the existing system without the addition of *new technologies*. If the improvement in the process is not sufficient to meet business needs *new technologies* can be considered in step two. The third and fourth steps are to apply financial risk assessment to the *new technology* alternatives. Application of a *new technology* is always perceived as a potential threat, therefore, financial risk assessment and reliability risk analysis help alleviate risks of investment. Finally, the fifth major step is to undertake a reliability analysis to ensure that the new system is safe and reliable.

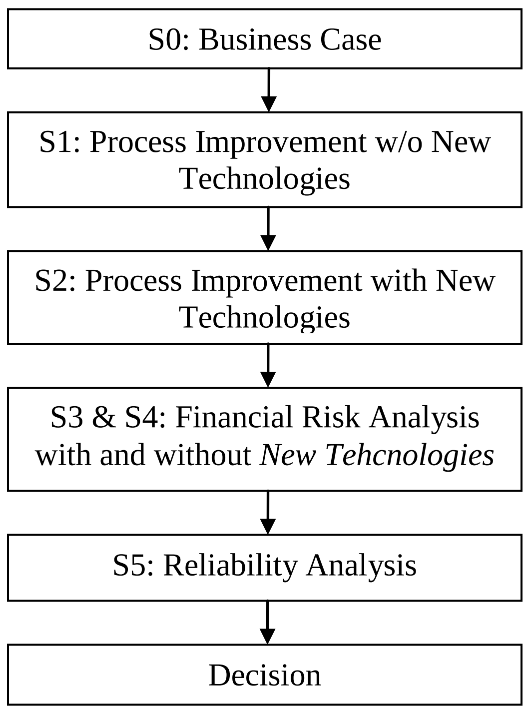


Figure 1.2 New Methodology

1.5 Motivation

Technological evolution is a continuous process, and it frequently leads to shifts in the competitiveness of industries. However, to be used effectively, the *new technologies* must be carefully selected and integrated to match the complex requirements of an overall process and achieve the required results.

New technologies can offer enormous opportunities and are crucial for profitable growth. The broad-spectrum technologies open up new and attractive business opportunities for the customers. Sustainable economic growth of the companies also requires innovative, efficient technologies and products. Companies are successful only if they achieve higher product yields and at the same time protect the environment. Companies that do not introduce *new technologies* are doomed to fail in the long run.

The process industry is capital intensive; capital investments for process improvement projects are from 30 to 60% of the process industry's expenditures. Therefore, selection of the right projects and technologies is crucial. The assessment of financial risks on various technology options helps to select the right projects. As a result, long-term asset valuation studies often include assumptions on the rate of technological innovation (reduction in heat rate and/or capital costs) for benchmark new entrant generation technologies. These assumptions determine the market prices at which new entrants will break even – the long-run marginal cost of electricity generation in classical economics and a key consideration in many market analyses over this time frame.

1.6 Case Study Problem Description

An industrial case study that has been well-defined in the literature was selected to implement and validate the new methodology. The case study is based on planning the design and operation of a fleet of power generating stations owned and operated by Ontario Power Generation (OPG), the largest electric utility company in Ontario, Canada.

The planning problem that Hashim (2006) considered was to develop a fleet of operating stations at minimum cost, while satisfying electricity demands and CO_2 emission constraints.

There are several promising new energy technologies which can achieve high energy savings and reduce greenhouse gas and have a good likelihood of success due to the economic, environmental, product quality and other benefits.

Three new dimensions need to address to solve this problem: 1) the expected return (or profit and loss) on each option or alternative in the portfolio; 2) the risk associated with the expected profit and 3) the role of efficient technologies and achievable solution.

1.7 Research Objectives

The main objectives of this research are as follows:

1) To develop and apply a systematic methodology and corresponding tools to support the decision-making process for the integration of various improvement options, including *new technologies*, into the existing mature processes. The methodology will

help improve productivity and cost effectiveness, reduce operating and capital costs and conserve mass and energy resources of mature petrochemical processes, such as ethylene styrene plants.

2) To contribute to the understanding of financial risk assessment of the selected options and technologies in supporting the decision process.

3) To combine the years of my industrial experience together with academic mathematical modeling, simulations and optimization.

The first objective is pursued by the review of existing methodologies in the literature and methodologies used in industry. The reviews help conduct a structure for the study of the pitfalls in the existing methodologies and improvements needed for the new methodology.

The second objective is pursued by analyzing the financial risks associated with selected options and their influence on the decision-making process.

The third objective is pursued by selecting the real industrial problem as a case study for the validation of methodology and applications of *new technology* integration and evaluating it based on knowledge gained from industrial experience.

1.8 Thesis Outline

1.8.1 Literature Review

In this phase, a comprehensive literature review of the existing methodologies and *new technologies* and prediction of future trends is performed. The literature review is described in Chapter 2, and it is divided into five main areas:

1) Summary of literature review findings

2) Current Methodologies

3) Components in Existing Methodologies

4) *New Technologies*

5) Financial Risk Management

1.8.2 Methodology Development

This phase presents the development of a systematic methodology for integrating *new technologies* into existing processes. The systematic methodology aims at improving the process cost-efficiency, performance and operation and supporting decision-making with financial risk assessment when selecting among the most profitable alternatives.

This is the key phase of the research in which a systematic methodology is developed after a comprehensive review of the existing literature and the selection criteria and identification of *new technologies* and tools to improve and integrate with existing processes as a unit operation. This phase is divided into five steps, which are described in detail in Chapter 3.

1.8.3 Validation

The methodology is validated using a case study. Ontario Power Generation (OPG) energy planning with CO_2 emission considerations is selected as the case study to apply various stages in a real system. The new methodology is compared with the existing methodology and validates the results. The results show that the process performance is highly influenced by

- technological development and
- financial risk assessment.

The case study that is considered for this research is a real industrial project. Identification of a suitable project is not an easy task and is constrained by various criteria suitable for the technology to be tested. This phase is described in Chapter 4, 5 and 6.

1.8.4 Results Analysis

The results of the case study and recommendation of future work are discussed in Chapter 7.

The expected outcomes of this research are as follows:

- Development of an approach to continually improve mature processes that result in sustainable delivered value to the business.
- Development of a mathematical model that can help in better understanding the trade-offs between financial risks and profit in a capital planning decision. It also suggests a solution with higher expected profit with lower risk.
- Identification, selection and integration of *new technologies* into existing mature processes to have a positive impact on the sustainability of the companies and ability to remain competitive in a global market.

The research offers a number of contributions in the area of integration of *new technologies* into the existing mature processes considering financial risk analysis.

- A new complete methodology is introduced for the integration of *new technologies* into existing mature processes. It systematically analyzes processes for improvement potential opportunities and evaluates these opportunities by a modular indicator framework that also supports the decision-maker in selecting the right technology.

- Introduction of financial risk assessment analysis as part of the methodology. The selected technologies are assessed in order to determine the risks of investment.

2. Literature Review

2.1 Introduction

The literature review is divided into the following subsections:

- Summary – Literature review findings
- Retrofit options and methodologies – Review of existing methodologies and methodology used in industries
- Screening of alternatives methods used in current retrofit methodologies
- *New Technologies* – Review of *new technologies*, which are already developed by various licensors, vendors, or various agencies such as the Department of Energy (DOE) or research institutes small business industrial research (SBIR). It also includes review of *new technologies* of power plants.
- Financial Risk Management – Review of literature related to financial risk management, stochastic programming and conditional value at risk.
- Process Reliability Analysis – Review of literature related to process reliability analysis

2.2 Summary – Literature Review Findings

Several methodologies for process retrofit and design have been developed during the last three decades. The focus is usually placed on only one or two tools or steps. There are several steps, such as integration of *new technologies*, financial risk management and process reliability analyses are not included in these methodologies. However, the previously proposed methodologies help to develop the new proposed methodology. The following are some highlights of the literature review:

- Evaluate the significant structural alternatives for the design of the new plant and then integrate alternative into the existing structure. Finally, select the best flowsheet after heat integration.
- Integrate knowledge base energy optimization by using operating pinch calculations (OPC), design pinch calculations (DPC), minimum equipment modified principle (MEMP) and minimum capacity extended principle (MCEP).
- Set objectives, establish team, identify bottlenecks based on experience and solve by computer simulation. Finally, add methods for bottlenecks.

- Improve the existing flowsheet by modifying equipment or adding new equipments, selecting additional operating units and finally heat integrating the whole process.
- Employ process energy integration for optimizing and reducing energy consumption in process industries.
- Develop systematic procedure and framework for screening and retrofitting by using different reaction path.
- Use of cost diagrams to identify and screen alternatives and then find the best flowsheet. The equipments are modified based on the selection of an alternative.
- Identify alternatives by using economic model and formulating superstructure and solve the problem by using MINLP.
- Consider the constraints and anticipated disturbances for process reliability and operability and their impact on operating cost for the process

Early retrofitting work is limited to single retrofitting objective and limited retrofitting strategy. The retrofitting methods are based on:

- Design of process alternatives – synthesis step
- Screening & selection of optimal alternatives – decision step

In the basic methodology, the process flowsheet decomposes into component path flows. The component path flows are assessed with performance indicators. Then it identifies and evaluates retrofit options on the basis of the flow assessment.

In the expanded methodology, the process is optimized with regard to retrofit options that do not require investment. The model is developed and used to select options. The next step is to perform feasibility as well as the economic profitability of the retrofit options that require investment. In this step, the model is modified and the most profitable option is selected.

There is no set methodology that every industry can use. Typically, the methodology starts with the business case, the evaluation of the existing system and exploration of some *new technologies* available in the market. Then the final decision on the selection of the new process flowsheet is based on return of investment (ROI) or net present value (NPV). There is no concept of model development for screening alternatives. Financial risk management and reliability analysis are not part of the methodology.

Many algorithms and techniques have been developed to synthesize and optimize processes. One of the most evident problems in the industries is the evaluation and integration of existing plants. The plant can be retrofitted to achieve business objectives. However, the retrofit problem is sometimes difficult because of many constraints such as space, operating conditions, etc. This has received little attention in the literature. The work in retrofit design has been limited because of above difficulties. In some cases, the research focuses primarily on modifying a particular subsystem or equipment type. The same problem could be encountered with integration of *new technology* if the systematic methodology is not used.

The several techniques and approaches are proposed in the literature to screen alternatives such as experienced-based approach, application of various optimization methods and in some cases optimization is combined with thermodynamic methods.

2.3 Retrofit Options and Methodologies

Retrofit implies changes to the structure of a new flowsheet and/or to some equipment sizes in order to increase profitability of the plant. It may, sometimes, include changes in technology. The design of a processing plant consists generally of recursive three steps: synthesis, analysis and evolution. The design procedure repeats all steps until the economics of the detailed plant cannot be further improved.

Several retrofit methodologies were developed in the 1970's, 1980's and 1990's. These methodologies cover only selected areas but help establish the basis for the retrofit methodologies developed in 2000's.

Before 1980's, retrofit design focused on the overall process and tends to simplify a system in order to apply mathematical models to analyze and evaluate a given problem. In this approach, algorithmic and thermodynamic methods are used. Algorithmic methods make use of structural optimization strategies to analyze, evaluate and select the best process alternative. A good pre-selection is required due to a large number of alternatives.

The retrofit design method to improve the overall cost efficiency was presented by Fisher et al. (1985). The sensitivity analysis is combined with elements of the hierarchically structured and heuristically-driven method for grassroots design introduced by Douglas (1985). Sensitivity analysis is used to optimize the parameters with respect to overall production cost. This method is then used to design new structural alternatives for the complete process as if the existing plant were to be completely replaced. Grossmann et al. (1987) estimated that 70-80% of all process design projects were dealing with the retrofitting of existing process plants. Only few systematic design and decision methods are available to the decision-maker that handles complex tasks. The importance of retrofitting and integration of *new technologies* and lack of systematic methodology are the motivation for this research work.

Grossmann and Floudas (1987) describe the maximum allowable variation range of uncertain parameters in order to maintain operation. The method makes use of a flexibility index. A retrofit design method that focuses on improving the flexibility in plant operation was presented by Pistikopoulos and Grossmann (1988, 1989).

Point source reduction is the best waste monitoring procedure for three reasons:

- Reduction of emissions to the environment
- Prevention of generating new emissions
- Reduction of waste treatment cost and reduction of energy

There are several methods that have been presented for grassroots design. A scheme for grassroots design was presented by Gunderson (1989). It comprises knowledge-based systems, design methods based on heuristic rules and optimization methods.

Nelson and Douglas (1990) developed a systematic procedure and a software code created to examine continuous petrochemical plant retrofit problems. The authors refined the procedure described by Fisher et al. (1987). Fisher's procedure is easy to describe but is very difficult to implement with a conventional process simulator. Douglas implemented the procedure in a way that demonstrates its utility in a wide variety of industrial problems. The obvious way to implement and demonstrate the procedure was to develop an interactive complete code suitable for use by a process engineer and use the code to retrofit as many industrial plants as possible.

The steps in Fisher's procedure are useful and necessary but are not implemented in software. He provides a framework for screening retrofit projects. Preparing an operating cost diagram is a necessary step done before an engineer approaches the computer. It is the fundamental step of gathering data about the process and placing it on an appropriate diagram. On the basis of this diagram, a decision is made on whether additional retrofit work on a specific project is merited.

Several retrofit design methodologies presented in the literature handle the problem of energy and waste minimization. Douglas (1992) improved the design of new processes. The method was originally developed for grassroots design which can be applied to retrofit design. This was later validated by Fonyo et al. (1994). Later Van der

Helm and High (1996) and Dantus and High (1996) proposed two approaches for waste minimization. Both approaches are structure in a procedure that includes three main steps:

- Base case modeling of the existing process
- Identification of retrofit alternatives
- Optimization with regard to economic performance

Rapoport et al. (1994) developed a retrofit design algorithm that uses a process synthesis approach with heuristic rules based on engineering experience, detailed process calculations and detailed economic evaluation leading to an optimal design. The approach is tested on an existing aromatic plant.

Rapoport et al. (1994) conducted the design in hierarchical levels and relevant heuristic rules are used at each level. Most of the rules are applied automatically. Some rules are left to the discretion of the designer. The paper is presented about the expanding the production capacity of a plant and use incentive of using new raw materials.

The employment of process energy integration technology is an important approach for reducing energy consumption in the chemical process industry. Huiquan and Pingjing (1998) develop the energy savings retrofit method. The overall process system can be looked upon as a large heat exchanger network and process integration can be treated as matches between the hot streams and the cold streams in constrained and unconstrained cases. This simplifies the process heat integration.

Optimization of existing systems is carried out in two steps: diagnosis and evolution of energy utilization. In the diagnosis of energy utilization, the heat flow profile is precisely described within the plant. With the information obtained from the first step, optimizing measures are further adopted to reduce energy consumption in the second step. Pingjing classified pinch analysis (PA) as operating pinch calculation (OPC) and is used in the diagnosis step, whereas design pinch calculation (DPC) is used in the evolution step.

In the course of deciding a grassroot design, he followed two principles i.e. maximum capacity extended principle (MCEP) and minimum equipment modified principle (MEMP). The first, MCEP, intends to make full use of the capacity of existing equipment, and the latter, MEMP, aims to minimize the number of pieces of existing equipment to be retrofitted.

Zhu and Asante (1999) use pinch technology to generate HEN designs and find the best solutions with optimization strategies. A similar work that was included in the work of Zhu and Asante was further adopted by Kovac and Glavic (1995) and Kovac-Kralj et al. (2000). Later it was extended to the retrofitting of entire processes with respect to energy consumption. There are two steps:

- Generation of retrofitting alternatives by combining heuristics and pinch technology
- Formulation of generated alternatives in superstructure

Ben-Guang et al. (2000) describe the methodology for retrofitting chemical processes based on experience of several industrial retrofit projects. The paper focuses on the bottleneck of the plant, which is also the objective of retrofitting.

The main objective of process retrofitting includes increasing the production capacity (bottlenecking), efficiently processing new raw materials, reducing environmental impact and reducing operating cost. Although usually one main objective is set for a retrofit project, the other objectives are also considered simultaneously due to the existing new processes and knowledge and the changed constraints and regulations.

Guinand (2001) proposes a broad approach in retrofit design which includes formulation of retrofit incentive, process analysis, generation of alternatives and selection of the best alternative. Halim and Srinivasan (2002) introduce the new retrofit design method for waste minimization. In this approach an expert system is used to visualize the flow of materials in continuous process. However, work is less developed than presented by Guianad (2001).

There has been pressure from industry to focus attention on mitigating the detrimental impact on the environment, conserving resources and reducing the intensity of energy use. These efforts have gradually shifted from a unit-based approach to a system-level program. Therefore, the past decade has seen significant industrial and academic efforts devoted to the development of holistic process design methodologies that target energy conservation and waste reduction from a systems perspective.

Dunn and Halwagi (2003) addressed this challenge in their paper. The design methodologies are collectively referred to under the general heading of process integration design methodologies. It is based on fundamental chemical engineering and systems principles and therefore provides a set of generally-applicable tools. The tools provide an attractive framework for the holistic analysis of process performance and the development of cost-effective and sustainable solution strategies. The paper also presents some industrial applications, driving forces and hurdles to implementation, common features and some key results. These methodologies are limited to particular process system integration. However, the tools can be applicable to overall systematic methodology. They describe some of the process integration design tools for addressing energy conservation and waste reduction.

2.3.1 Industrial Methodology

The industrial methodology is based on industrial experience. It is not systematic and does not include financial risks and reliability analysis associated with six alternatives in order to support the decision. The discussions are carried out with various industries' representatives to determine their methodologies for process improvement. A questionnaire was prepared to get feedback from industrial specialists on the methodology used in the industry. The questionnaire and responses are described in Appendix A. From their feedback, it appears there is no set model or step-by-step methodology for the improvement of an existing process. There is no concept of developing a model and detailed evaluation of *new technologies* to improve an existing process. Management defines the business intent and goal. After defining the business case, the various options and *new technologies* are evaluated based on various economic tools such as net present value (NPV), return of investment (ROI) and the company's growth strategy.

The major weakness of the assessment of *new technology* is the way we integrate *new technology* into old plants. The *new technology* may be great, but it may require complete revamping of the current equipment in an old plant. There is a financial risk because sometimes integration of *new technology* may cost more than a new plant. Financial risk management is a critical part missing in the methods as per a senior licensing technology manager (Appendix A). Financial risk management, reliability analysis and screening and ranking of alternatives using a model must be incorporated.

There is no rigorous mathematical evaluation of various alternatives and evaluation of risk in the current methodology as per responses received from Shell division (Appendix A). This could be because the staff is not trained in those tools. Therefore, the decisions on investment are not sound.

2.4 Screening of Alternatives

Alternate solutions are generated when more than one alternative process or technology is identified that can be applied to reduce the cost or improve the efficiency of the process. The selection of which alternative to choose might be made on the basis of rules or some evaluation at the time the technologies or alternatives are being examined.

There are several techniques in the literature in screening of alternatives. They are:

- Pinch technology
- Cost diagrams
- Economic evaluation
- Process synthesis
- Modeling
- Optimization
- Superstructure

Initially, the pinch technology is used to evaluate alternatives. Although pinch technology cannot guarantee rigorous cost minimization, it can generate network with maximum heat recovery which often correspond to optimal or near optimal solutions. A number of concepts have been proposed to retrofit heat exchanger network. They consisted of:

- the retrofit design concepts that use the pinch technology, which was first introduced to design optimal heat exchanger (Linnhoff and Flower, 1978).
- the estimation of minimum utility requirements, minimum number of units, modification of pinch points, the number of heat exchanger units and heat exchanger area (Linnhoff, 1982).

The cost diagram is an approach to summarizing cost information at the initial stage of the design. It is very common practice to tabulate the operating costs and capital costs. All the utility costs are added separately as a single item (Ulrich, 1984; Peters and Timmerhaus, 1980). These costs can be used for checking the economics of process alternatives.

The cost diagrams help to identify the most significant design variables. The basic concept of cost diagrams is described by Douglas et al. (1985) in his paper. The diagrams show the base case cost data on a simplified flowsheet diagram. The annualized installed capital cost of each piece of equipment is listed inside of the equipment box on a flowsheet and the operating costs are attached to the stream arrows. The procedure comprises three stages:

- Allocate heat exchanger costs to process streams

- Lump sum costs associated with a processing step such as reactor, cooling
- Allocate costs to gas and liquid recycle loop or fresh feed streams

Douglas and Woodcock (1985) indicate in their paper that the cost diagrams are often useful for checking rules of thumb, for obtaining quick estimates of the economics of process alternatives and for establishing a hierarchy of optimization variables. The cost diagrams help to provide only a quick analysis to:

- Identify the significant design variables
- Infer structural modifications
- Check rules of thumb
- Evaluate process alternatives

Screening process alternatives using Douglas and Woodcock's (1985) quick screening procedure are an appropriate tool when suitable computer software is not available, but when software is available; it is simpler and faster to use the software to design in more detail all the significant structural alternatives.

The mathematical programming techniques are introduced, and they made significant contributions in the screening of alternatives (Jones et al. 1986; Ciric & Floudas, 1989). The heuristic methods used for creating and screening process alternatives are based on experiences. The heuristic methodology is also covered in the mathematical programming, but they are no longer frequently used as an independent method to improve the performance of a retrofit or screening of alternatives.

The mathematical methods are simultaneous, but they are difficult to solve for complex and energy intensive processes because the number of variables increases with the number of combinations. The algorithmic approach depends on the use of mathematical programming in simultaneous optimization.

Douglas and Nelson (1990) implemented the procedure in the software. The basic approach is to first get a target by designing the best new plant in order to focus attention on a smaller group of flowsheets. Then input the existing plant and resolve any modeling differences. Then the approach examines the best flowsheets neglecting the energy integration but in the context of the existing equipment sizes. At the end it performs energy integration targeting the best remaining flowsheet or flowsheets.

The sensitivity analysis, together with a hierarchical method (Douglas and Stephanopoulos, 1995) was used as a starting point to identify possible alternatives and to generate the MINLP superstructure.

Jaksland et al. (1995) describe in the paper a thermodynamic based synthesis for generating and screening process alternatives for new processes and existing processes. However, Kovac and Glavic (1995) used combination of thermodynamic and algorithmic methods for complex energy intensive processes. The thermodynamic method is known as pinch analysis. It is a powerful technique in the synthesis of utility system and the results of the methods can be used to postulate superstructure as described by Zhu, O'Neil, Roach and Wood (1995).

Recently, the optimal retrofit combines two or more methods by using limitation of energy or sizing of processes. Maechal and Kvalitventzeff (1996) combine pinch analysis and mathematical techniques:

- Propose a set of utilities that may meet the minimum energy requirement
- Use a mixed integer linear programming (MILP) optimization to select the utilities to be used

The economic model is also used to evaluate alternatives. It takes into account the capital and manufacturing costs associated with a specific process. The final decision criteria to select a specific alternative will rely on an economic incentive of this alternative Dantus and High (1996).

When comparing different process alternatives, the optimum alternative selected will be one that satisfies production demand with a minimum cost. This is important, as the cost minimization approach is focused not only on the manufacturing process cost itself but on the product life cycle, from raw materials to final disposition.

The MINLP model is applied in the structural and parameter optimization of utility plants as explained by Fernandez, Bruno, Castells and Grossmann (1998). It included combined advantages of the thermodynamic, heuristic and mathematical concepts by using many boundaries.

The optimization approach to process synthesis involves three steps: the representation of alternatives through a process superstructure, the mathematical modeling of the superstructure and the development of an algorithm for the solution of the mathematical model. Each of these steps is crucial to the determination of the optimal process flow sheet (Adjiman, Schweiger and Floudas, 1998).

Samikoglu et al. (1998) describe the procedure for sensitivity analysis and present a case study of project network with task name, duration, resources utilization of A and B and success probability. The key uncertain parameters considered in this work are the probabilities that a project will be terminated during the R/D process as a result of failure of a task to meet regularity, economic, or other performance requirements.

Related work on this topic arises in the areas of optimal project portfolio selection and optimal task ordering. In the former case, a MILP model is used to take into account uncertain project completion, but only in the objective function. This is done using a limited number of scenarios and does not consider the stochastic effects on the resources constraints. In the latter case, a model is considered that assumes all projects can be handled independently and thus does not address the limitations of a finite resource, only an optimal ordering of project task is developed such that the expected cost is minimized.

The MINLP approach is the best tool for simplified models. A study was performed by Phongpipatpong and Douglas (2003) on the optimal design of a rice processing plant. A problem was made in which a set of decision variables were determined and six objective functions were evaluated. The influence of each parameter on optimal flowsheet was determined by using the sensitivity analysis. The solution depends on the initial starting point due to the nonconvex nature of MINLP.

The integration of new processes and retrofit problems require the high-level detailed model in order to capture all of the design and operation parameters most affected by process modifications. The model helps to evaluate and identify alternatives and options. Jackson and Grossman (2002) propose to address the problem using a hierarchical approach and mathematical programming tools. The focus of their paper is on the development of the high-level model. The formulation of detailed models for each of the processes in a plant network is a cumbersome task involving the collection of many types of data. In fact, the data collection step alone may be too time-consuming to make process modeling worthwhile

The model is used to predict bounds for the best process performance information independent of detailed design modifications. The assumption is made in this paper that major modifications considered are typically for increasing production capacity and/or conversion and for improving energy recovery. The proposed MILP model can easily be extended to handle cases where it is necessary to rank the potential value of each of the proposed retrofit modifications or alternatives. Model building can be divided into four phases (Himmelblau and Lasdon, 2001):

- Problem definition and formulation

- Preliminary and detailed analysis
- Evaluation
- Interpretation application

In plant operations, benefits arise from improved plant performance, such as energy consumption, higher processing rates and longer times between shutdowns. Optimization can also lead to reduced maintenance cost, less equipment wear and better staff utilization. It is extremely helpful to systematically identify the objective, constraints and degree of freedom in a process and plant, leading to such benefits as improved quality of design, faster and reliable troubleshooting and faster decision making. The following attributes of processes affecting costs or profits make them attractive for the application of optimization:

- Sales limited by production
- Sales limited by market
- Large unit throughput
- High raw material or energy consumption
- Product quality exceeds product specifications
- Losses of valuable components through waste streams
- Higher labour costs

Optimization is applied in all integration problems in four primary areas (Reklaitis et al., 2006):

- Design of components or entire system
- Planning and analysis of existing system
- Engineering analysis and data reduction
- Control of dynamic systems

The process of optimization via a model allows the optimum of the real system to be found without experimenting directly with the real system.

Uerdingen et al. (2003) discuss the methodology in 2003 for screening options to improve the economics of a continuous chemical process. The methodology is divided into three stages. The first stage of the methodology is the path flow decomposition procedure, which decomposes a process sheet into a set of path flows of each component in the process. In the next stage, these component path flows are assessed independently with various economic and physiochemical performance indicators and are subsequently ranked according to an economic performance measure. Finally, options are identified on the basis of the path flow assessment results, ranked according to their economic impact potential and finally discussed with regard to their technical feasibility.

This methodology is limited to screening of alternatives with the help of economic performance measures. The results only demonstrate how the new method supports the systematic identification of economically beneficial retrofit options for chemicals.

In this methodology, various options are considered within the same flow sheet. The main focus is on variable cost, which includes raw material consumption and energy and waste costs. The energy waste and material cost and total cost impact potentials are calculated for the existing and for the generated structure retrofit alternatives. The results are then sorted according to the total cost impact potential in descending order.

Uerdingen et al. (2005) expanded the methodology in 2005. They introduce a new design method for screening, identifying and evaluating the options targeted at improving the cost efficiency of a continuous chemical process. The methodology is organized into five steps.

Fisher et al. (1985) presented a method for developing and screening opportunities. The second phase of methodology comprises step 4 and step 5. In step 4, the identified optimization parameters are investigated. In step 4-1, a local sensitivity analysis is carried out by means of rigorous process flow sheeting simulation with the identified optimization parameters. In step 4-2, the variable process costs are minimized in a parameter optimization by manipulating the most cost-sensitive optimization parameters. In step 4-3, the process constrains encountered sensitivity analysis and parameter optimization is finally used to generate additional structural alternatives.

Once the process is optimized with respect to the identified optimization parameters, the method continues with the evaluation of the generated structural alternatives in step 5. In step 5-1, attainable variable process cost savings are calculated by means of rigorous process simulation for all structural alternatives with regards to the previously optimized process as a benchmark.

In step 5-2, the alternatives that incur the highest cost savings are selected and detailed technical implementation scenarios are formulated on the basis of general engineering knowledge and experience.

In step 5-3, a preliminary investment cost study for each generated scenario is carried out and the scenario that incurs the least investment costs is selected. In step 5-4, if economic profitability is probable, the technical implementation scenario has to be evaluated for a number of important criteria such as compliance to environmental restriction, process safety, plant space requirements and others. In step 5-5, the technical implementation scenario is studied in detail in the modified flow sheeting simulation and optimized with regard to the variable process costs. This information is used to calculate the profitability of the scenario in detail with appropriate economic profitability measures.

Mendivil et al. (2005) study the influence of technology, market situation and environmental regulation on a chemical process during its lifetime. The methodology proposed to obtain the potential improvements of a process is based on four steps.

Three steps are required to obtain the evaluation of the economic and environmental performance of a process. These steps to be taken are data collection, data analysis and assessment. The data collection step indicates the technological advances of the process involved in the life cycle of the process from the study of patents, scientific literature and other sources of information, such as industry data or personal communications. In the data analysis step, the technological advances are introduced into a process simulator. The final step is the combination of a state-of-the-art retrofit methodology and the evolution of the economic and environmental performance to obtain potential improvements in the process. The study focuses on only limited technologies.

The technological improvements are introduced without optimizing the existing system without *new technologies*. Financial risk management is not considered. The methodology is not complete. However, this study is used to expand the methodology to incorporate other missing steps.

2.5 *New Technologies*

<u>Definition</u> – *New technologies*, for the purpose of this thesis, are novel technical concepts, process methods and tools, which are engineering and science based and can contribute to new knowledge for process improvement and cost reduction, which are proven and have not been used in the process to date.

New technology is the application of science to especially industrial and commercial objectives. For example, it includes the use of materials, tools, techniques and sources of power to make industry more productive and to make life easier and more pleasant. The following are a few examples:

- The new technological processes, inventions, methods, or branch of knowledge that deal with one type of process but that are new for other processes, such as catalyst additive, catalyst, heat recovery from gases and hydrocarbon recovery from membranes

- The *new technologies,* well-proven in one process, applied to other processes with minor modifications, such as coatings, glass, fibreglass, UV cure, nanoparticles, catalysts, etc.

- The *new technologies*, tested in the pilot plant and well-proven, used in a large scale plant or processes, such as IGCC, NGCC, batch to continuous process, turbine, etc.

- The new raw materials, which have the same composition but are obtained from other sources, such as glycerine from biofuel refinery

The technologies are characterized with respect to type of industry:

- Chemical
- Power generation
- Pulp & paper
- Refining & petroleum
- Polymer & coatings
- Glass & fibreglass
- Food
- Automotive
- Information

In this thesis, a case study involving the electricity generation sector is developed. The *new technologies* for power generation are grouped in the following categories, which derived from DOE 2020 and Association of Energy Engineers:

- Coal technologies

    - Advanced gasification

    - Advanced separation

- Air separation
    - Hydrogen recovery
- Hydropower
    - New turbine design
    - Hydro-matrix design for small turbines
- Hydrogen
    - Quench gasification with conventional acid gas removal
    - Advanced hot gas cleanup with ceramic membrane
    - Advanced entrained gasification with pressure swing adsorption
- Wind
    - New turbine design
    - New coating
    - New materials for turbines and blades
- Solar
    - Thin-film photovoltaic
    - Leap-frog
    - New polymer and nanostructure
- Nuclear
    - New reactor design and control
- Carbon capture and sequestration
    - New membranes
    - Advanced scrubber
    - New sorbent
    - Inexpensive oxygen

- Chemical looping

- CO_2 hydrates

Above are promising new energy technologies, which can achieve high energy savings and reduce greenhouse gas and have a good likelihood of success due to the economic, environmental, product quality and other benefits.

2.6 Financial Risk Management

2.6.1 Introduction

Financial risk management introduces a mathematical formulation to evaluate and manage financial risk and uncertainty. The formulation helps the decision maker to maximize the expected profit and at the same time minimize the financial risk at every profit level. The trade-offs between risk and profitability and the cumulative risk curves are found to be logical way to visualize the risk behaviour of different alternatives. There is a need to develop new models that allow not only assessing but managing financial risk.

Stochastic programming is a framework for modeling optimization problems which involve uncertainty. Deterministic optimization problems are formulated with known parameters. The most widely applied stochastic programming models are two-stage linear programs. In two-stage programming, uncertainty is modeled through a finite number of independent scenarios. Scenarios are formed by random samples taken from the probability distribution of the uncertain parameters as explained by Barbaro et al. (2004). The decision maker has two simultaneous objectives:

- Maximize expected profit
- Minimize risk exposure

Typically, the uncertain parameters are:

- Prices
- Availability
- Market demands
- Process yields
- Rate of interest
- etc.

2.6.2 Stochastic Linear Program Formulation

Stochastic programming can be viewed as an extension of mathematical (i.e. linear, integer, mixed-integer, nonlinear) programming but with a stochastic element present in the data:

- In deterministic mathematical programming, the coefficients are known numbers.
- In stochastic programming, these numbers are unknown; instead we may have a probability distribution present.

Stochastic programming is typically applied to two types of problems:

- Probabilistic constraints
- Recourse problems

Stochastic programming deals with situations where there is uncertainty present. The fundamental idea behind stochastic linear programming is the concept of recourse. Recourse is the ability to take corrective action after a random event has taken place. A simple example of two-stage recourse is the following:

1. Choose some variables, x, to control what happens today.
2. Then, overnight, a random event, z, happens.
3. Then, tomorrow, take some recourse action, y, to correct what may have changed by the random event.

Optimization problems can be formulated to choose x and y in an optimal way. There are two periods; the data for the first period is known with certainty and some data for the future periods are stochastic, that is, random.

In the planning stage, some decisions are taken before random or uncertain events are known. The other decisions are taken only after the uncertain data become known. The planning stage decisions are called fist stage decisions before the uncertainty represented by design variables such as place an order now, pick a reactor volume or a number of trays, or sign a contract.

The decisions are made after uncertainty is called second-stage or recourse decisions. They are represented by control variables. They are taken in order to adapt the plan or design to the uncertain parameters realization.

A large and useful collection of literature exists on two stage stochastic programming modeling from 1959 through 2006. At the beginning it started with several methods to deal with uncertainties such as the so-called chance-constrained optimization (Charnes and Cooper, 1959), fuzzy programming (Bellman and Zadeh, 1970; Zimmermann, 1987) and the design flexibility method (Ierapetritou and Pistikopoulos, 1994). Some references on a two-stage stochastic programming include books by Infanger (1994), Kall and Wallace (1994), Marti and Kall (1998, Uryasev and Pardalos (2001) and Verweij et al. (2003). Gothe-Lundgren et al. (2002) discussed a production and scheduling problem focused on planning and scheduling to select mode of operation to use to satisfy the demand while minimizing the production cost. A recently developed stochastic model (Pongsadki et al., 2006) that includes uncertainty and financial risk expanded to the effect of pricing.

2.6.3 Financial Risk Management via Portfolio Optimization in the Power Generation Industry

Economic needs and the ongoing trend of liberalization of the electricity markets have stimulated the interest of power utilities players to develop operating models and the corresponding mathematical optimization techniques that effectively address the issue of generation and trading of electric/electrical power under uncertainty (Gröwe-Kuska, Heitsch and Römisch, 2003).

In the regulated world, the owner of a portfolio or fleet of generation plants had to solve the economic dispatch (minute by minute) and unit commitment (hourly) scheduling problems. Deregulated energy markets and the emergence of centralized physical markets in electric power run by ISO (independent system operators) organizations have resulted in complexities pertaining to managing market risks in both operations and financial aspects (Denton et al. 2003).

The unit commitment problem deals with the short-term schedule of thermal units in order to supply the electricity demand in an efficient manner. In this type of model, the main decision variables are generators start-ups and shut downs (Ventosa, 2005). In other words, the problem concerns how to most economically schedule the generating units considering the unit economics, physical constraints and incremental transmission losses such that the operator's total commitment to deliver power is met (Wood and Wollenberg, 1996).

In classical investment portfolio theory, optimizing the expected return for a specified level of risk is a well-known problem as optimized in the seminal Nobel Prize-winning work of Markowitz (1952, 1959 and 1991). Three dimensions are addressed in this problem: 1) the expected return (or profit and loss P&L) on each instrument in the portfolio; 2) the risk associated with that profit (as measured by variance (or standard deviation) in the expected profit by Markowitz's mean variance (MV) model or by other alternate measures of risk, such as value at risk (VaR) or conditional value at risk (CVaR); and 3) the quantity of each instrument held.

2.6.4 Conditional Value at Risk (CVaR)

A measure of risk that goes beyond the information revealed by value at risk (VaR) is the expected value of the losses that exceed VaR, thus termed as CVaR. This quantity is also called expected shortfall, mean shortfall, conditional loss, excess loss or tail VaR (Rockefeller and Uryasev, 2000).

In two-stage stochastic programming, the expected value of the total costs is minimized. Recently, mean-risk models have attracted attention in stochastic programming (Schultz and Tiedemann, 2006). In this work, we consider the minimization of the conditional value at risk (CVaR), the most preferable risk measure in financial risk management within the context of the well-known problem of electrical power planning (and capacity expansion), which is originally formulated as the maximization of the expected profit or the minimization of the expected cost. For general distributions, the conditional value at risk is defined as a weighted average VaR and the expected losses that are strictly greater than VaR.

Financial risk associated with the energy planning case study is defined as the probability of not meeting a certain target cost minimization level referred to as α. CVaR is a powerful measurement of financial risk. With respect to a specified probability level β, α is the lowest amount such that with probability β, the cost will not exceed α and CVaR is the conditional expectation of cost above the amount α. In other words, CVaR means the expected value of the cost in the case that the probability that the cost exceeds α is $1 - \beta$. Usually β is pre-selected as 0.95 or 0.99.

The CVaR of the losses of the portfolio is the expected value of the losses, conditioned on the losses being in excess of VaR. It follows from the definitions that CVaR is always greater than or equal to VaR. Both VaR and CVaR are functions of the asset allocation vector x and the percentile parameter α. It is natural to seek to minimize these measures by judiciously specifying the composition of the asset portfolio. VaR is difficult to optimize when calculated using discrete scenarios.

In order to minimize cost of electricity generation and minimize financial risk at the same time, a mathematic formulation, which is called mean-risk model, is introduced. Bagajewicz (2004) has shown that a solution that minimizes financial risk at cost minimization target also minimizes the expected value of cost of power generation.

When the weighting factor increases, *Cost* increases, while *Risk* decreases. *Cost* is the total cost of electricity generation, including capital investment, operational cost and penalty cost for power under-production/over-production compared to the demand load. *Risk* is the expected value of total cost of electricity generation exceeding a certain target α, and its probability is $1 - \beta$. CVaR is applied to measure the financial risk. λ is a suitable weighting factor. The mean-risk model aims at minimizing the weighted sum of two competing objectives.

The objective function value does not change for all changing weighting factors. It changes only for certain effective points, which is the same as Schultz's conclusion and results.

2.7 Process Reliability Analysis

The primary criterion for process operability is that all of the constraints are satisfied for the full range of anticipated disturbances. The operability of a process is ensured by either over designing of the equipment or bottleneck of the equipment. Over design will increase the annualized capital costs, whereas operating away from equipment constraints may increase the expected annual operating costs for the process. Thus, the economic trade-offs for each of our operability alternatives is considered to minimize risks.

<u>Operability & Control:</u> Faith and Morari (1979) considered the use of multiple-objective performance measures to balance the dynamic and steady-state characteristics of new design. Swaney and Grossmann (1982) have developed a flexibility index that indicates the size of the parameter space where feasible operation can be attained. Unfortunately, the analyses required to apply these new procedures are fairly sophisticated, so that they should prove to be more useful for the evaluation of final designs rather than as screening tools.

Fisher and Douglas (1985) present a hierarchical procedure for assessing the steady-state operability of a process. The method can be applied as new processes are being designed, or it can be used as a decomposition procedure for studying the operability of existing processes. The initial assessment of process operability may be undertaken at the same time as a process is being developed.

In the initial stages of a process design, where we are still screening numerous process alternatives, it is helpful to have a shortcut procedure available for evaluating process operability. If a flowsheet cannot be made operable, we must modify the flowsheet or consider another alternative. Also, by estimating the cost of restoring operability of each alternative, we can improve the selection of the best flowsheet structures.

The design problem is decomposed into the following hierarchy of decisions:

- Continuous or batch
- Input – output structure of the flowsheet
- Recycle structure of the flowsheet and reactor considerations
- Separation system specification
- Vapour/liquid recovery system
- Heat exchanger network

Douglas (1985) describes in detail the design decisions and economic trade-offs encountered at each level. By estimating the economic potential after each level, un-profitable designs may be abandoned with minimum effort. Douglas also applied the design decisions on an example – Hydrodealkylation of Toluene to Benzene (HAD).

<u>Waste Minimization:</u> In the 1960's, waste treatment was considered contingently only after the plant was constructed. In the 1980's, waste treatment gained consideration before the construction of the plant but was not integrated in the process design. In the 1990's, significant progress was made in process synthesis concerning environmental issues; however, the routine design procedures stayed almost the same as before. In the 2000's, it was integrated into R/D phase where all materials are required to be "green" by green chemistry.

Because of the large quantities of materials and energy used by the chemical industry, significant opportunities are available for waste reduction. Each year, the US industry generates about 12 billion tonnes of industrial waste and uses about 30 quads of energy to produce goods. Peters and Daniel (1992) describe in their paper that industry seeks to improve efficiency of its operations. Process modifications, raw material changes and other actions needed to significantly reduce wastes are often technologically risky and require significant investment. Waste may be reduced by consideration of the following techniques, used singly or in combination with one another:

- Improvements of process selectivity and/or conversion
- The ability to operate at lower temperatures and/or pressures
- Process requiring fewer steps
- Products and/or catalysts with longer lives

- The use of feedstock having fewer inherent by-products
- More efficient equipment design
- Innovative unit operations
- Innovative process integration
- New uses for otherwise valueless by-products
- The avoidance of heat degradation of reaction products
- The elimination of leaks and fugitive emissions

Sowa (1994) presents many questions and issues related to waste minimization that process simulation can address. It shows how simulation tools can make measurable improvements in batch process performance, which can be applied to the continuous process. While the main emphasis is on waste minimization, several aspects of process safety such as relief systems and vapour flammability need to be covered. The systems are:

- Direct solvent recovery
- Liquid extraction
- Vapour/liquid absorbers
- Solids handling
- Physical property generation
- Evaporative emissions
- Relief systems
- Flammability

Yang and Shi (2000), attempted to summarize the developments of this area in the last ten years in order to clarify what has been accomplished to date and what should be possible in the near future from an industrial point of view. Also, several points are identified for future research. The authors explain that the environmental concerns are getting more and more advanced in the life cycle of the process.

Safety and Environmental: With some exceptions, the major focus of environmental, health and safety (EHS) professionals has been on costs and compliance rather than on strategic business advantages that could be derived from a new way of looking at EHS opportunity.

EHS have financial impacts on organization from fatalities, injuries and resource damages. Therefore, the understanding and management of these can have a considerable impact on a company's heath. The goal is not necessarily to minimize the risks but to evaluate them so that informed decisions can be made about critical investments from among many different alternatives. Nourai et al. (2001) explain EHS criteria for targeting waste reduction in chemical processes. The key advantage of risk management is that it offers a systematic framework with scientific foundations to assess and prioritize diverse risks and to make effective use of resources for protecting public health and the environment. However, risk assessments have been mainly addressing a single type of risk at a site or source. Lacking a broad context, there is typically no clear vision of the relative benefits of reducing a particular risk, the alternatives involved, time sensitivity and potential trade-offs across different facilities and types of risk. A set of scenarios (events) are generated and then their risks are calculated by trying to find the likelihood of occurrence of each event and the magnitude of its consequence.

3.0 Proposed Methodology

3.1 Introduction

Many industries are now paying increasing attention to *new technology* integration in order to maintain their profitability. As a result, the application and effect of technological development in industry opens a new opportunity for integration methodology. The current methodologies focus only optimization and on the state of the art of the technology. New advances in technology such as advances in chemistry, information technology, automation and material science, etc. have created a multitude of opportunities. To be deployed effectively, new technological opportunities need to be carefully selected to fit within an existing process. The new methodology is developed to help achieve these results effectively.

This chapter presents the proposed methodology for integrating *new technologies* into the existing mature processes. A study of the process using this new methodology, which includes identification and selection of *new technology* for the process or equipment, allows for more and better integration of *new technology*. The returns from incorporating the new methodology are high, but there is also some risk in implementing a *new technology*. Therefore, financial risk management is made a part of the methodology to mitigate these risks.

3.2 Proposed Methodology Steps

The proposed methodology involves the following five steps:

- Step 0 – Business case analysis
- Step 1 – Improvement of existing system <u>without</u> addition of *new technology*
- Step 2 – Improvement of existing system <u>with</u> addition of *new technologies*
- Step 3 – Financial risk management <u>without</u> *new technologies*
- Step 4 – Financial risk management <u>with</u> *new technologies*
- Step 5 – Reliability (operability & EHS) risk management

Figure 3.1 shows the steps of the proposed methodology.

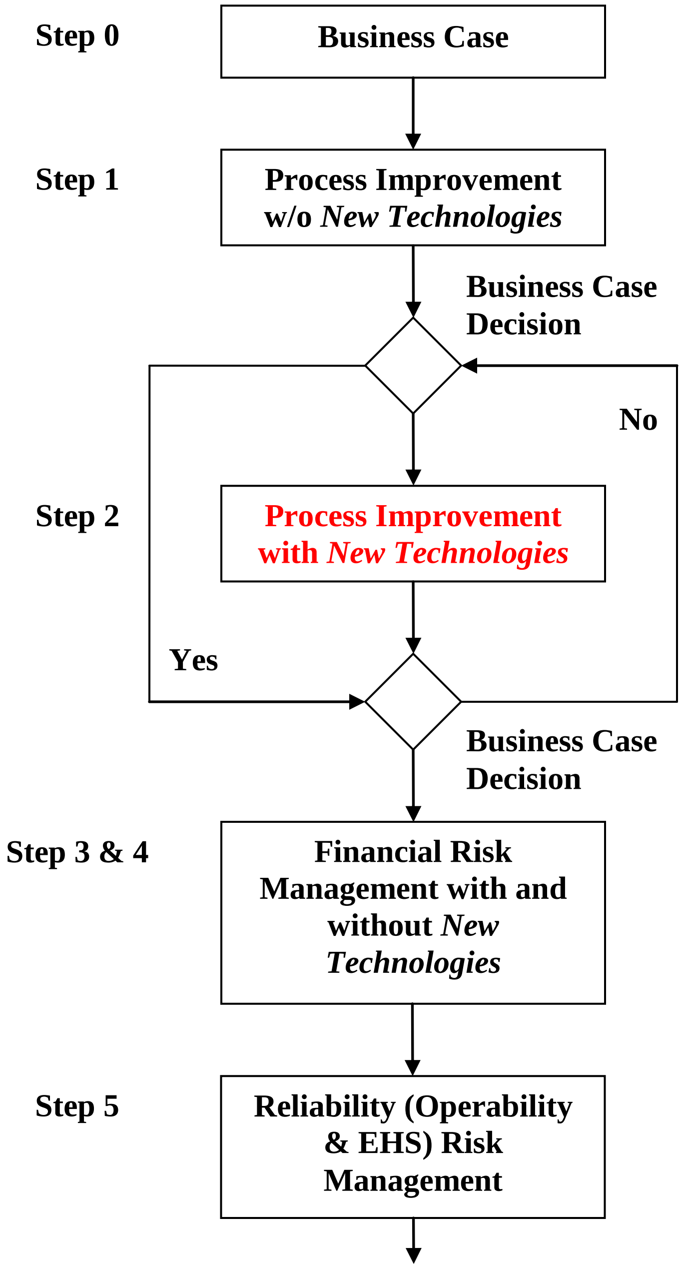
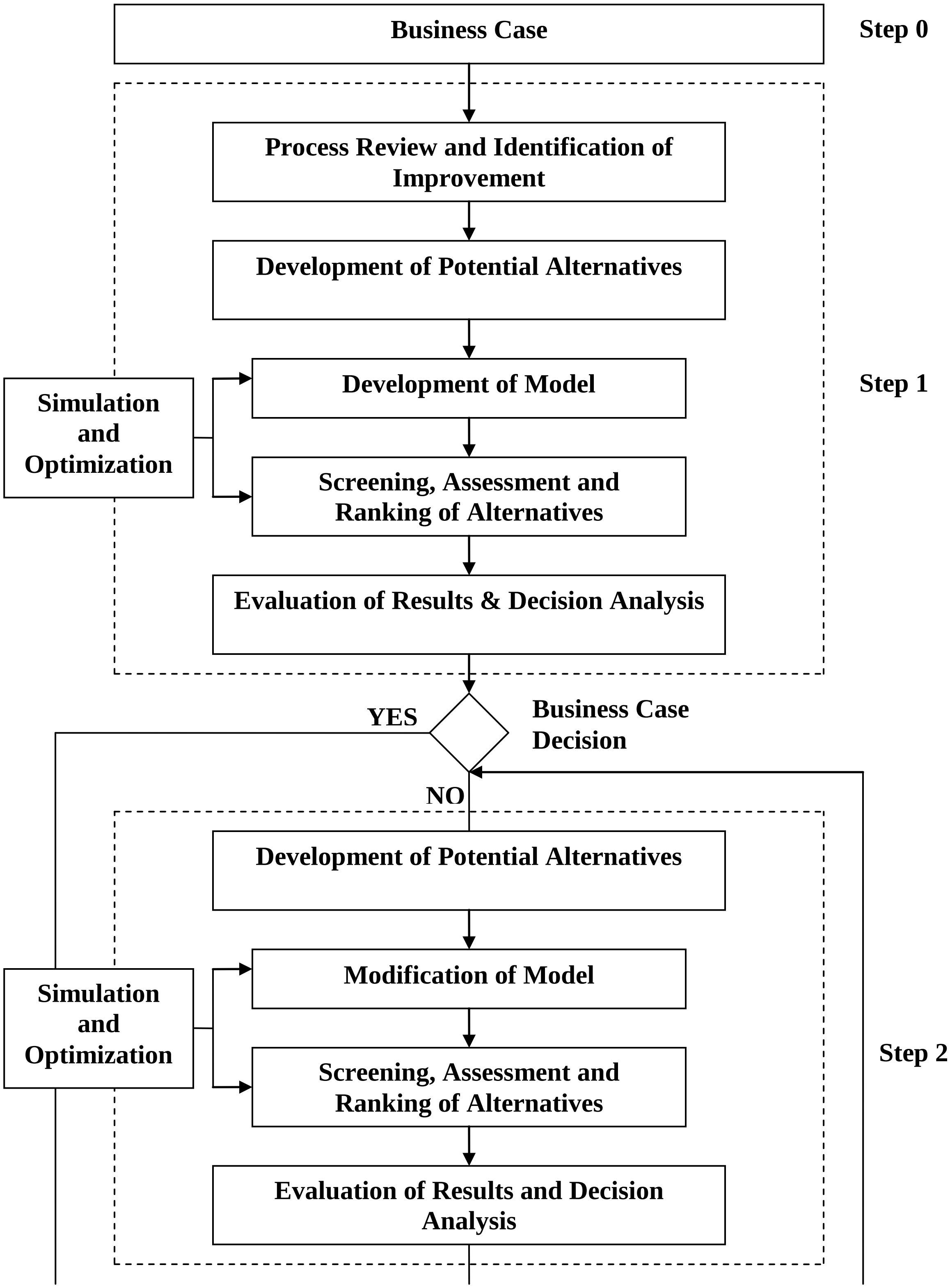


Figure 3.1 Major Steps of Proposed Methodology

The proposed methodology was developed after reviewing current industrial methodologies, the literature, tools to improve and integrate existing processes and *new technologies*. The proposed methodology is shown in more detail in Figure 3.2.


Business Case
Step 0
Process Review and Identification of Improvement
Development of Potential Alternatives
Simulation and Optimization
Development of Model
Screening, Assessment and Ranking of Alternatives
Evaluation of Results & Decision Analysis
Step 1
YES
Business Case Decision
NO
Development of Potential Alternatives
Simulation and Optimization
Modification of Model
Screening, Assessment and Ranking of Alternatives
Evaluation of Results and Decision Analysis
Step 2

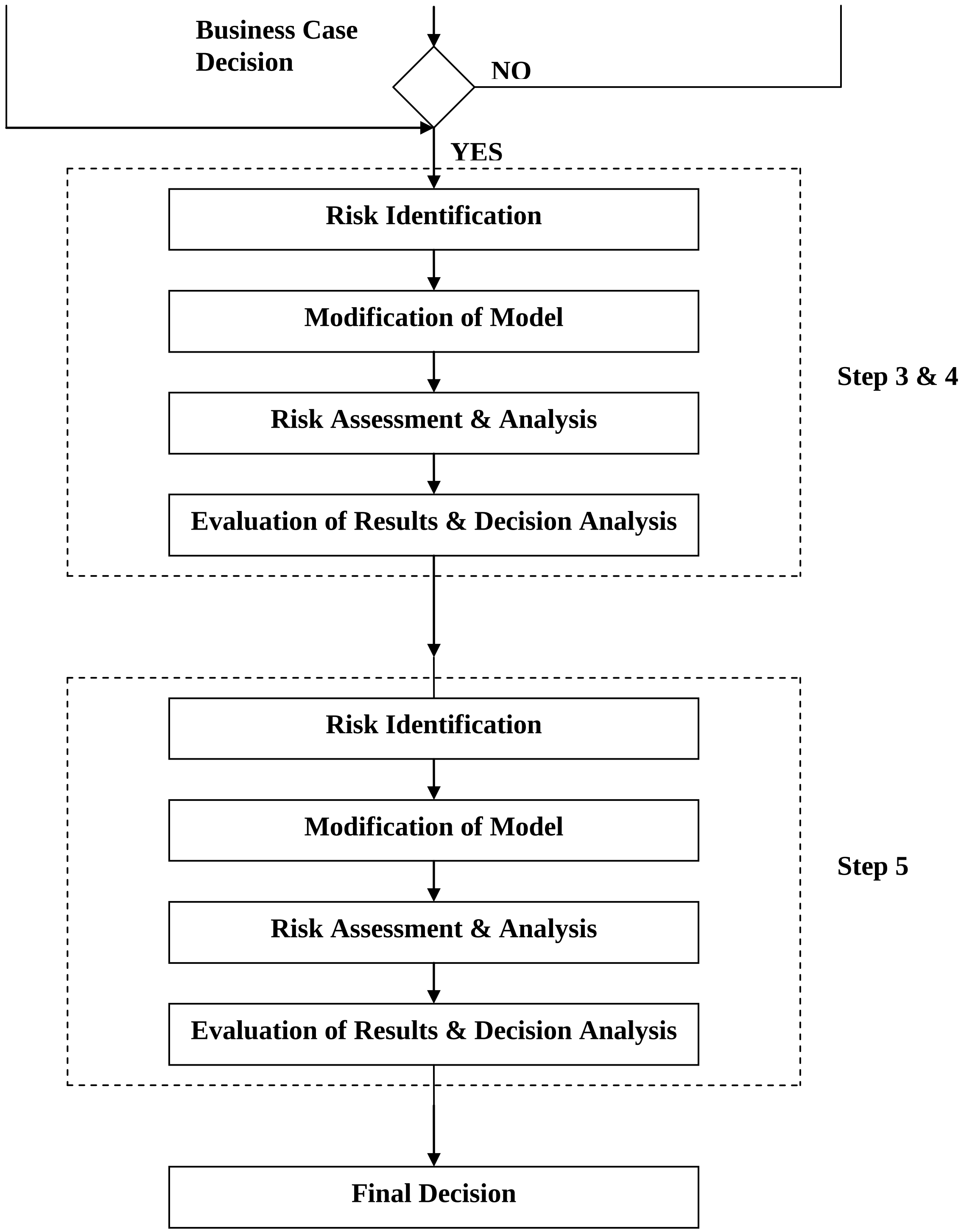


Figure 3.2 Detailed Steps of Proposed Methodology

3.3 Proposed Methodology

3.3.1 Step 0 – Business Case

The business case is a key component of the proposed methodology. It is important to lay out the business goal and the various constraints to achieve the results. The clearest way to present the business objective is to define the end results of the project. The common business objectives are:

- Capacity expansion
- New feedstock
- Energy savings
- Changes in the product specifications and quality
- Reduction of capital and operating costs
- Improvement of environmental performance

Depending on which external and internal conditions arise, different process improvement concepts are reviewed and justified in the business case. The evaluation and interpretation of the results of the internal and external analysis provide the basis for the business case evaluation.

Before a business decides to move forward, it requires a thorough understanding of business strategy and structure of conducting an internal and external analysis to address the questions that may be raised. The value of the internal analysis is in the evaluation and integration of the performance of the business with respect to its completion; that is, analyzing plan, goals, success factors, assumptions, tactics and actions.

This procedure also requires an analysis of the external environment; that is, analyzing competitors, social, political, economic and technological factors that are most likely to impact the general environment must be assessed. The information gathered in this external analysis, in conjunction with the internal analysis, provides a source basis for evaluating where a business stands against the competitors.

In the business case evaluation phase, the economics and scope of the work is analyzed from the incentives prospective. The integration of *new technologies* into the existing matured processes is a complex task and therefore, it requires a clear understanding of business case and scope of the project.

3.3.2 Step 1 – Improvement of Existing System without Addition of *New Technology*

3.3.2.1 Process Review & Identification of Improvement

The first step of the proposed methodology is to study the existing process. The business requirement, thorough review and flowsheet synthesis are the key factors in identifying the area of improvement. The undesirable features of the process are identified. Several approaches and algorithms have been developed to synthesize the process and identify the area of improvement. One approach is the hierarchical process approach, which is a complete evaluation of the process flowsheet. The flowsheet is divided into a set of path flows for each component in the process.

3.3.2.2 Development of Potential Alternatives

In this step, various alternatives are developed without using *new technologies*. For most part it will focus on optimization of existing system. A typical approach to identifying alternatives is first to develop a base case design. Then study the tools to generate a list of alternative decisions. The base case design gives us a starting point from which to generate improved alternatives. It also provides us with a solution for which we can estimate the actual profits.

For many types of process improvement opportunities, it is relatively easy to generate alternatives. There are some instances where generation of even a single feasible alternative, much less all possible alternatives, is extremely difficult.

3.3.2.3 Development of Model – Simulation & Optimization

In the development of the base case process model, the scope is determined by identifying the units and operation to be included. As more units are included, the model will become more accurate but will also make the solution more computationally intensive. The process model includes operations and units that have an important economic impact in the process.

The economic performance of the base case model is used as the evaluation criteria to analyze each process alternative. The economic performance is evaluated in terms of low capital cost and profitability. This is to measure the amount of profit that can be obtained from a specific process. The profitability criteria used is a function of both capital and manufacturing costs of changes, which include direct production costs, fixed charges, plant overhead costs and general expenses.

In this step, modeling and simulation are used to test different ways of operating a manufacturing system by optimization to find an alternative that satisfies the objectives of the business. Understanding these processes, improving them for particular needs, and expanding them will help to achieve desired results.

The use of the model involves the defining and assessment of alternatives and the interpretation and presentation of the outputs. Modification of the process requires an incentive. This incentive can be economical, quality, environmental, safety, etc. A base case process model is used to evaluate the current performance of the process and serves as a guide to analyze the different alternatives. Using general knowledge of the behaviour of process-systems, one can qualitatively judge the effect that a change of an operating parameter or the implementation of an alternative might have on the unit operations of the process. Once the qualitative evaluation has been carried out for all alternatives, the cost impact potentials are calculated for each alternative as follows:

- Energy and waste cost impact potential
- Material cost impact potential
- Fix and other operating cost potential
- Total cost impact potential

3.3.2.4 Screening, Assessment, & Ranking of Alternatives – Simulation & Optimization

In screening analysis, it is determined that whether the existing process/equipment can tolerate a large change in flows or other parameters. It is also important that any changes to the structure of the flowsheet will not make the integrated plant uncontrollable. The major potential problem with process controllability in an integrated analysis is the elimination of manipulative variables. This is true for highly energy-integrated processes. In order to determine the value of alternatives, the performance of each alternative is assessed. The performance determines how economic, safe/environmentally sound, flexible, controllable, etc. each alternative is in a process.

3.3.2.5 Evaluation of Results & Decision Analysis

The most important step in any process improvement effort is to identify the area of the process that really should get attention. Many options exist for improvement efforts. The incentives for process improvement are quantified. It is also important that the process flow schemes reflect actual plant operating conditions and material and energy balances to ensure a valid basis for the efforts. The following are the key criteria for evaluating process alternatives:

- Understanding the importance of process alternatives
- Pursuing significant improvement
- Using the updated process flow sheeting for the basis

- Understanding all aspects of the process
- Confirming the limitations

3.3.3 Step 2 – Improvement of Existing System with Addition of *New Technologies*

This section presents a systematic approach to integrate the evolution of technologies into the existing mature process in order to achieve the business goal. The steps are:

3.3.3.1 Development of Potential Alternatives

In this step, *new technologies* are identified and prioritized for process improvement. The goal is to achieve the business case expectations with the lowest possible cost. This goal is accomplished by identifying various *new technologies* and their operating conditions and then individually screening these alternative technologies to evaluate their overall economic impact on the business, product and production system as a whole.

Use of the superstructure approach for representation of alternative technologies involves three steps:

- The representation of alternatives though a process structure
- The mathematical modeling of the superstructure
- The development of an algorithm for the solution of the mathematical model

Based on the general knowledge of the behaviour of the process system, one can judge the effect of the implementation of a *new technology* might have on component path or unit operation of the process.

3.3.3.2 Modification of Model – Simulation & Optimization

The next step involves the mathematical modeling of the superstructure. Binary variables are used to indicate the existence of nodes within the network and continuous variables represent the levels of values along the arcs. The resulting formulation is a MILP.

The base case model is modified for evaluating *new technologies*. The model and simulation are used to test different ways of operating a manufacturing system to find an alternative technology that satisfies the objectives of the business.

3.3.3.3 Screening, Assessment & Ranking of Alternatives – Simulation & Optimization

New technology is evaluated on the basis of a rigorous simulation model that represents the whole process. A variation of process operating parameters is performed with sensitivity analysis with respect to the appropriate performance measure for a given incentive i.e. cost efficiency, flexibility, etc.

The best technologies are represented in a superstructure and solved by the modification of the process model. The best technology is then determined by optimizing the superstructure using simultaneous parametric and structured optimization (MILP). The *new technologies* are considered with the answer either yes or no.

3.3.3.4 Evaluation of Results & Decision Analysis

The optimum technology in the existing plant can be selected by using mixed integer linear programming (MILP) in which both linear relations among continuous variables and binary or integer variables that appear linearly.

The above method is used to select the technology in order to minimize cost. The continuous variables will be assigned to the different streams to represent the conditions. The decision analysis then assesses the merit of technologies by integer programming. MIP's are linear in the objective function and constraints and hence are subject to solution by linear programming. This is called mixed-integer linear programming (MILP).

The final step of the optimization approach is the development and application of an algorithm for the solution of the mathematical model. This step is highly dependent on the properties of the mathematical model and makes use of the structure of the formulation. This step focuses on the development of an algorithm capable of addressing the MILP.

The final decision for alternative technologies is done in four steps:

- Determine cost savings for each alternative technology by means of sensitivity analysis and process simulation model. Rank these in order to attainable cost savings and begin with best alternative.
- Compare the results of the best alternative with the business case to check whether it meets business objectives.
- If the results do not meet business objectives, then evaluate the other alternatives in Step 2. If the results meet the business objectives, then proceed to Step 3.

3.3.4 Step 3 & 4 – Financial Risk Management with & without *New Technologies*

The other major component of the methodology which influences business decision is financial risk identification and management. Risk is an uncertain event or condition that, if it occurs, has a positive or a negative effect on the process improvement or project. A risk may have one or more causes and, if it occurs, one or more impacts. The risk management is to modify the profit distribution in order to satisfy the preference of the decision maker. The risk is considered for both without *new technologies* and with *new technologies*.

3.3.4.1 Risk Identification

Risk identification step is to identify and categorize financial risks that could affect the project or alternative of the process improvement. The technical risk means that a project will fail to meet its performance and programmatic risk has the two major components of cost overrun and schedule delay. The external risks are influenced by market, nature and supply and demand. The examples are raw material price increase such as natural gas, coal, electricity and ethylene or demand of product increases or decreases. Moreover, the inherent level of uncertainty in forecast demands, availabilities, prices, technology, capital, markets and competition make the decision very challenging.

3.3.4.2 Modification of Model

Stochastic programming is a framework for modeling optimization that involves uncertainty, in which data or coefficients are unknown numbers; instead there is a probability distribution present. Deterministic optimization problems are formulated with known data or coefficient numbers. When the parameters are known only within bounds, the solution of these problems is called robust optimization. Stochastic programming is mathematical programming which includes linear, integer, mixed-integer and nonlinear programming.

The most widely applied and studied stochastic programming models are two-stage linear programs. The decision maker takes some action in the first stage, after which a random event occurs affecting the outcome of the first stage decision. A recourse decision can be made in the second stage that compensates for any bad effects that might have been experienced as a result of the first stage decision.

The mathematical formulation is used to assess and manage financial risk. It helps the decision maker to maximize the expected profit and at the same time minimize the financial risk at every profit level. However, the minimization of risk at some profit levels renders a trade-off with expected profit.

The classical two-stage stochastic linear program (SLP) with fixed recourse as originally proposed in the seminal works of Dantzig (1955) and Beale (1955). The models are developed for both without and with *new technologies*.

3.3.4.3 Risk Assessment Analysis

The financial risk costs for the alternatives are estimated at various scenarios of penalty for not meeting demand or overproducing power. The objective is not to minimize the risks but to evaluate them at various scenarios so that the decision can be made about capital investment from among many different alternatives or scenarios.

In order to minimize cost of electricity and minimize financial risk at the same time, a mathematic formulation which is called mean-risk model is introduced. The mean-risk model aims at minimizing the weighted sum of two competing objectives. As weighting factor increases the financial risk management becomes more important while cost minimization turns less important. However, it does not mean risk model objective function value changes as weighting factor does.

When the weighting factor increases, cost increases while risk decreases. Cost is the total cost of electricity generation including capital investment, operational cost and penalty cost for power overproducing or under-producing than demand load. Risk is expected value of total cost of electricity generation exceeds a certain target α and its probability $1 - \beta$. CVaR is applied to measure the financial risk. The objective function value does not change for all changing weighting factor. Only for certain effective points it changes which is the same as Schultz's (2006) conclusions and results.

3.3.4.4 Evaluation of Results & Decision Analysis

Sensitivity analysis is also a modeling tool that is used to assist in evaluating individual risk, which is very important in risk management. However, they are used only on the most difficult and complex improvement projects because of their complexity. The following are key considerations for decision making, risk mitigation and risk management.

The risk response options helps formalize risk management. It is important to identify the best strategy for each risk then initiate specific actions to implement that strategy. Once there is a clear understanding of risks and their magnitude and options for response, a mitigation strategy is emerged. The plan includes the reduction of the probability or consequences of a risk event to acceptable threshold. Although mitigation steps are costly and time consuming, they are still preferable to going forward with the unmitigated risk.

3.3.5 Step 5 – Operability & EHS Risk Management

In this section, there will be an empirical investigation of the impact of technology integration on the performance of the plant. In addition, the performance of each stage also depends on the configuration of the plant. Adding, removing, or modifying a section of the process anywhere in the overall process affects the performance of the plant.

Process hazards and operability risk management is critical for any process change and integration of *new technologies*. This is due to the tightening legislation, energy & production cost, pollution and increasing pressure from customers and nongovernmental organizations.

The effectiveness of the process improvement is linked to the generation of knowledge about the interactions between new approaches and existing capabilities of the plant. This involves evaluating the impact of specific changes in the technologies employed. The effective execution of these changes will require broad knowledge of the existing characteristics of the plant and impact on operability, safety and the environment.

Operability, Safety and Environmental concerns change conceptual process designs a lot. They bring about extended system boundary, inherent multi-objectives and more constraints. All these changes influence further screening of path, generating flow sheet alternatives and selection of operability methods, environmental and safety criteria and optimization methods.

3.3.5.1 Risk Identification

The main objective for Operability & EHS risk analysis is that all of the constraints are satisfied for the full range of anticipated disturbances. The Operability & EHS analysis has several important implications for process improvement and technology integration.

The operability of a process is ensured by either over designing the equipment or applying suitable operating procedures. Over design will increase the capital cost, whereas operating procedures may increase the expected operating cost of the process. The economic trade offs for each of our operability alternatives may be considered. The overall goal is to discover the economic impact of operability problems rather than rigorous calculations.

- The recommended changes should be realizable in practice
- The operability and reliability impacts should be fully defined in practical terms

The purpose of the operability analysis is to identify additional changes needed to control a plant. These costs should be included in the decision-making process. The following three areas are part of process operability.

- Controllability
- Reliability

- Flexibility

One of the methods for identifying operability risks is life-cycle assessment. This is an established, comprehensive method that is intended for use as a decision support tool in improving performance. It is applied to products and processes. Another method is total process analysis. The Operability & EHS risks are caused by some of the following reasons:

- Limitation of equilibrium
- Effects of disturbances
- The feed & product quality
- Changes in cooling system loop
- Reactor conversion control versus reactor temperature control
- Over pressure of the system
- Sequences of distillation column
- Energy integration limitations

3.3.5.2 Modification of Model

In this step the model is modified to include Operability & EHS risk analysis. The goal of modeling is to accomplish accurate quantification in as realistic a situation. This involves the need for quantifying in the presence of uncertainty. The model should ultimately be reflective of a probabilistic approach. This includes selection of appropriate metrics, development of a model and conducting an appropriate operation analysis. The deterministic part of the model provides a top view of the requirements and allocations. The probabilistic analysis part of the model provides the operations processing estimate to compare against the goals and requirements. The first part is experience base and the second part is based on estimate of actual design decisions.

With the help of modified mathematical model, each risk can be assessed for its impact on the selection of alternative or *new technology*. Using the simulated model, the risks, efficacy, efficiency and benefit of any improvement can be examined. This requires incorporation of operability, safety and environmental components of the simulation model. The modified model should be flexible enough to examine each component. The complete model includes:

- The process model, financial risk model and operability risk model are integrated into a common model using a standard commercial simulation program.

- Both risk assessment and cost benefits analysis have important roles in overall decision and risk management.

3.3.5.3 Risk Assessment Analysis

The initial assessment of process Operability and EHS risks may be undertaken at the same time as the consideration of alternatives. The primary criterion for process operability & EHS is that all the constraints are met for the integrated design. If a flowsheet cannot be made operable and hazard free, the flow sheet must be modified or consider another alternative. By estimating the cost of operability & EHS risks for the alternative, the selection of the best flow sheet structure can be improved. The objective is not necessarily to minimize the risks but to evaluate them so that the decisions can be made about capital investments from among many different alternatives.

For risk assessment the probability of occurrence of an event and the probable magnitude of its adverse effects are estimated. A set of scenarios of various events are generated and then their risk is calculated by trying to examine:

- The likelihood of occurrence

- The magnitude of it occurrence

The steady-state analysis is useful to determine whether or not additional process units are needed to ensure operability of the plant. Both the incremental capacity and the additional units add to the design costs, and these additional costs need to be included when process alternatives are compared and for the detailed cost estimate and decision-making process. Short cut calculations and procedures normally are adequate for preliminary design when numerous process alternatives are being considered. For a tightly integrated plant, the heat supplied at the base-case design conditions might satisfy base case only. However, in these situations, operability problems will be encountered when disturbances enter the distillation column, so it might be necessary to have an auxiliary re-boiler for control purposes. The proposed control systems should be adequate to handle all disturbances. The disturbances entering a process correspond to changes in the assumptions about how a process is connected to its environment. Therefore, the disturbances correspond to changes in the process variables. It is very important that any recommended modifications in the process design be made very early in the design stage rather than later.

The hierarchical procedure can be used for assessing the steady-state operability of the design. In this case the effects of the disturbances on the design variables are examined in a hierarchical of their importance. Therefore, input and output flows are the most significant variables, and the recycle flows are the next most important. The loads on the liquid and vapour recovery system should be considered last. The simplified procedure should be considered since the operability analysis is to examine the economic impact of operability issues rather than detailed calculations.

3.3.5.4 Evaluation of Results & Decision Analysis

In this step, results of various operability, safety and environmental analysis are evaluated and discussed. The effects of the variables that are linked by the nature of the process are examined. Risk-based approach helps in finding what is reasonably possible with the scope of the business case rather than what is desired. The results from this approach can form basis for risk mitigation or risk free alternative.

Sometimes, manipulation of operating variables can lead to improve operability and reduce pollution. This is only increases the operating cost, which is only marginal. In addition, this makes plant more reliable and profitable. The non-process variables can also be incorporated in optimization. The examples are the geometry of stack design and type of packing. The evaluation of results and decision analysis include:

- Exploration and implementation of the most cost-effective modifications.
- Utilization of a scientific basis for evaluation of problems.
- Decision on operability and EHS strategy.
- Obtaining insights as to how risks can be possible be reduced, before any costly improvement.
- Optimization and reduction of investment of risks mitigation.

There are several other factors that are considered in results evaluation and decision making process:

- Costs associated with risks
- Business case requirements
- Pollution and hazards associated with the change

3.4 Validation of Methodology

The proposed methodology is validated by applying it to an existing case study and comparing it to literature results. A problem based on Ontario Power Generation (OPG) energy planning with CO_2 emission considerations is selected as the case study to apply various steps in the real system. The proposed methodology is compared with the existing methodology and validates the results. The results show that the process performance is highly influenced by the technological development and financial risks assessment. The case study, which is considered for this research, is a real industrial project. Identification of a suitable project is not an easy task and is constrained by various criteria suitable for the technology to be tested. The case study and results are described in more detail in Chapters 4, 5 and 6.

4.0 Case Study – Background & Business Case

4.1 Overview

The proposed methodology was tested on a case study based on the electricity sub-sector in Ontario described by Hashim et al. (2005). The case focuses on planning the capacity supply to meet the projected electricity demand for the fleet of electric generating stations owned and operated by OPG (Ontario Power Generation) with a goal to minimise total annualised costs while satisfying various CO_2 emission constraints. The results show that achieving the CO_2 emission mitigation goal while minimizing costs affects the configuration of the OPG fleet in term of generation mix, capacity mix and optimal configuration.

The case was chosen for several reasons. Firstly, it represents a typical situation in which an established industry/process needs to be modernised and/or expanded by adding new equipment/processes to its plant(s). Secondly, it is a well defined and published case with which we can compare our results. Finally, the proposed case study helps analyze the role of *new technologies* (efficient energy technologies) to reduce energy costs and/or offset CO_2 emissions.

4.2 Background of Case Study

As the case study is based on Hashim et al. (2005), all of the relevant data are taken from this source so that comparisons between Hashim et al.'s (2005) approach and the approach developed here can be made.

The majority, 70%, of Ontario's electricity is produced by Ontario Power Generation (OPG) which relies on fossil fuel combustion for about 28.5% of its generating capacity, with the remaining amount produced by hydroelectricity (27%), nuclear energy (44%) and renewable or other energy sources, such as wind turbines (0.5%). In 2002, OPG emitted approximately 36.7 million metric tonnes of CO_2 mainly from coal-fired power plants while generating about 115.8 TWh of electricity with total in-service capacity of 22,211 MW. OPG operates approximately 79 electric generating stations which include five coal fired plants, one natural gas generating facility, three nuclear generating plants, sixty-nine hydroelectric generating stations and one small wind turbine facility. A summary of OPG's current fossil fuel generating stations is contained in Table 4.1 with the number of boilers at each site given in the fifth column (Hashim, 2005).

Table 4.1 Ontario Power Generation Fossil Fuel Power Stations

Generating Station	Fuel	Heat Rate (GJ/MWh)	Net Capacity (MW)	Number of Units	Annual Capacity Factor	O&M Cost ($/MWh)	CO_2 Emission (tonne/MWh)
Nanticoke1 (N1)	Coal	9.88	500	2	0.75	30	0.93
Nanticoke2 (N2)	Coal	9.88	500	6	0.61	30	0.93
Lambton1 (L1)	Coal	9.84	500	2	0.5	34	0.94
Lambton2 (L2)	Coal	9.84	500	2	0.75	25	0.94
Lakeview (LV)	Coal	10.8	142	8	0.25	35	0.98
Lennox (LN)	NG	7.82	535	4	0.15	50-70	0.65
Thunder Bay (TB)	Coal	11.7	155	2	0.55	30	1.03
Atikokan (A)	Coal	9.82	215	1	0.44	30	1.03

The operational costs for nuclear plants were estimated at $32/MWh; hydroelectric plants to be $5/MWh, the wind turbine facility at $4/MWh; and natural gas the most expensive of all at $70/MWh (Hashim, 2005). All coal-fired boilers were assumed to operate at 35% efficiency and base load demand was considered constant throughout the year at the nominal level of 13,675 MW (Hashim, 2005).

The Kyoto Protocol, developed by the United Nations Framework Convention on Climate Change (UNFCC), required that Canada reduce its greenhouse gas emissions by six percent relative to 1990 levels by 2008-2012. The use of *new technologies* is required for deep reductions in CO_2 emissions. There are currently no CO_2 capture or storage (CCS) processes installed at any OPG facility. Strategies to capture or mitigate CO_2 emissions for fossil fuel power plants would include:

- Increasing efficiency
- Fuel balancing or fuel switching
- Increased use of renewable energy sources (e.g., wind turbines, solar, biomass) and
- CO_2 capture and sequestration.

4.3 Step 0 - Business Case

The goal of this study is to determine the optimal configuration of the fleet of power plants, fuels, carbon capture and sequestration, new power plants and *new technologies*, which can meet projected electricity demands and satisfy various CO_2 reduction targets at minimum cost and with minimum financial risks. The business case considers planning for various increases in electricity demand (1%, 5%, 10% and 20%) combined with the possibility of reducing CO_2 emissions by various amounts (6%, 20%, 40% and 60%) from the 1990 levels.

The business case considers:

- Optimal growth strategies
- CO_2 reduction strategies via fuel balancing, fuel switching and CO_2 capture
- Sensitivity to:
    - Incorporation of *new technologies*
    - Increases in fuel prices
    - Incorporation of financial risk management

5.0 Case Study – Deterministic Model

Improvement of Existing System without & with *New Technologies* (Steps 1 & 2)

5.1 Step 1 – Improvement of Existing System without *New Technologies*

5.1.1 Identification of Problem

The problem is to reduce the amount of CO_2 emitted from OPG's fleet of power plants at low cost and to determine optimum power plants mix by using existing technology under business case scenarios.

In this section, mathematical model formulation for the case study is presented in detail. The case study consists of a structured optimization study of the Ontario Power Generation (OPG) system of power plants. The goal of the optimization is to minimize the cost of electricity, while meeting a given CO_2 reduction target. Power plants are grouped as follows:

- Fossil fuel plants
- Renewable plants (nuclear, hydroelectric and wind)
- New fossil fuel plants

which are notated as *f*, *rn* and *p*, respectively, in the model formulation; nuclear is grouped with renewable plants only because CO_2 emissions from nuclear plants are assumed to be zero. Two possible options, namely fuel balancing and fuel switching, are used here for reducing CO_2 emissions. Fuel balancing is the optimal adjustment of the electricity generation of different power plants to reduce cost and/or CO_2 emissions, and fuel switching is the retrofitting of fossil fuel plants from carbon-intensive (i.e. coal) fuels to less carbon intensive fuels (i.e. natural gas).

5.1.2 Development of Potential Alternatives (without the use of *new technologies*)

The first step of the proposed methodology is to develop a list of potential alternatives without the use of *new technology*. The existing power plants with existing technology include fossil fuel stations and renewable energy stations. The renewable energy technologies involve nuclear, hydroelectric and wind. The fossil fuel technologies include pulverized coal (PC) and natural gas (NG). OPG's existing power plants are listed below:

- 6 fossil fuel generating stations (27 boilers):

  4 boilers at Lambton (L);

8 boilers at Nanticoke (N);

1 boiler at Atitokan (A);

8 boilers at Lakeview (LV);

4 boilers at Lennox (LN);

2 boilers at Thunder Bay (TB);

The capacity of each of the coal fired power plants, above, is:

$L_{\max} = 4323020 MWh / Year$

$NN_{\max} = 4292400 MWh / Year$

$A_{\max} = 1883400 MWh / Year$

$LV_{\max} = 1246110 MWh / Year$

$LN_{\max} = 4686600 MWh / Year$

$TB_{\max} = 1357800 MWh / Year$;

- 71 renewable generating stations

  3 nuclear power plants;

  67 hydroelectric power plants;

  1 wind turbine plant.

To meet the aggregate electricity demand and/or CO_2 emission limitations, the OPG fleet of generating stations will need to be modified and/or added to. Without the use of *new technology*, the following alternatives were proposed:

Alternative 1: Fuel Balancing

Fuel balancing is the adjustment or balancing of the electricity output from various generating stations to reduce CO_2 emissions i.e. increasing the operation of nuclear plants and reducing the operation of coal fired generating stations.

Alternative 2: Fuel Switching

Fuel switching refers to switching or retrofitting carbon-intensive (i.e. coal) generating stations to less carbon intensive fuels (i.e. natural gas).

Alternative 3: Addition of New Generation Capacity

New existing technology generating stations can be added to the fleet to increase the supply of electricity. Existing technology includes pulverized coal (PC) and natural gas combined cycle (NGCC). The optimization programme is set up to "select the optimal technologies from grocery store shelves and add them to a shopping cart". Therefore one needs to make sure that the "grocery store is well stocked" with various alternatives; if the optimizer cannot find the alternative it wants, it will be forced to choose sub-optimal alternatives. We have, therefore, provided the optimizer with two PC generating stations (each with four boilers) to choose from and three NGCC generating stations (each with four boilers) to choose from. PC1 and PC2 are two coal power generating stations. Each power station has four boilers: COAL11, COAL12, COAL13 and COAL14; COAL21, COAL22, COAL23 and COAL24. NGCC1, NGCC2 and NGCC3 are three natural gas power generating stations. Each power station has four boilers: NGCC11, NGCC12, NGCC13 and NGCC14; NGCC21, NGCC22, NGCC23 and NGCC24; NGCC31, NGCC32, NGCC33 and NGCC34.

- 2 PC stations each with 4 boilers

  PC1 consisting of COAL11, COAL12, COAL13, COAL14;

  PC2 consisting of COAL21, COAL22, COAL23, COAL24;

- 3 NGCC stations each with 4 boilers

  NGCC1 consisting of NGCC11, NGCC12, NGCC13, NGCC14;

  NGCC2 consisting of NGCC21, NGCC22, NGCC23, NGCC24;

  NGCC3 consisting of NGCC31, NGCC32, NGCC33, NGCC34;

PP1 and PP2 are the capital and operating costs of the new coal power generating plant without CO_2 capture. PN1, PN2 and PN3 are the capital and operating costs of the natural gas power plant without CO_2 capture. The capital costs of new PC and NGCC plants (both without CO_2 capture) are:

$$PP1 = 1578000 \text{ \$}/MW; PP2 = 1413000 \text{ \$}/MW;$$
$$PN1 = 617000 \text{ \$}/MW; PN2 = 552000 \text{ \$}/MW; PN3 = 442000 \text{ \$}/MW;$$

The operating costs of the new PC and NGCC plants (both without CO_2 capture) are:

$$PP1 = 2.53 \text{ \$}/MWh; PP2 = 2.47 \text{ \$}/MWh;$$
$$PN1 = 8.1 \text{ \$}/MWh; PN2 = 9.37 \text{ \$}/MWh; PN3 = 8.3 \text{ \$}/MWh;$$

5.1.3 Model Development

In this step, the mathematical model formulation for the case study is presented in detail. The model was formulated as a mixed integer linear programme (MILP) and implemented and solved using GAMS (Generalized Algebraic Modeling System, algorithms and computer codes to solve large mathematical programming problems) (Boisvert, Howe and Kahaner, 1985). The optimization model selects certain power plants in order to minimize cost, while satisfying the aggregate electricity demand resulting in an optimal mix of power plants for various scenarios.

Power plants are divided into the following types: fossil fuel plants, renewable plants, including nuclear, hydroelectric and wind, new coal and natural gas fossil fuel plants without CO_2 capture, which are notated as *f*, *rn* and *p*, respectively, in the model formulation. Three options:

- Fuel balancing
- Fuel switching and
- New generating capacity
    - Pulverized coal (PC)
    - Natural gas combined cycle (NGCC)

are used here for meeting aggregate demand and/or reducing CO_2 emissions by a certain target.

5.1.3.1 Objective Function

The objective cost function consists of the following costs: capital investment cost (\$/MW) for all power plants (*Capital*), retrofit cost (\$/MW) for fossil fuel plant, retrofit and operating cost (\$/MWh) for all power plants (*Operating*).

$$\min TotCost = Capital + \mathrm{Re}trofit + Operating \tag{5.1}$$

$$Capital = \sum_{p} F_p \cdot A_f \cdot \frac{P_{\max}}{T} \cdot X_p \tag{5.2}$$

$$\mathrm{Re}trofit = \sum_{f} R_f \cdot \frac{F_{\max}}{T} \cdot A_f \cdot X_{f,'ng'} \tag{5.3}$$

$$Operating = \sum_{f,j} (O_f + \mathrm{Pr}_j \cdot HR_f) \cdot E_f + \sum_{rn} O_{rn} \cdot E_{rn} + \sum_{p,j} (O_p + \mathrm{Pr}_j \cdot HR_p) \cdot E_p \tag{5.4}$$

The variables include binary variables and positive variables. Binary variables are used to determine capital investment cost, where $X_{f,j}$ is for fossil fuel plants selection and fuel type decision, j includes two types of fuel, coal and natural gas; $X_{r,n}$ and X_p are to decide whether to build renewable plants or new fossil fuel plants; positive variables are E_f, E_{rn} and E_p, which represent the electricity generation amount for fossil fuel plants, renewable energy plants and new fossil fuel plants process, respectively.

5.1. 3.2 Model Constraints

The minimization of the objective functions represented above is subjected to the following constraints.

Energy Balance/Demand Satisfaction:

The total electricity generation, *TotE*, must be equal to or greater than the desired electricity demand.

$$TotE = \sum_{f} E_f + \sum_{rn} E_{rn} + \sum_{p} E_p \tag{5.5}$$

$$TotE \geq (1+Ge) \cdot E_d \tag{5.6}$$

Ge is gross percentage of electricity demand i.e. 1%, 5%, 10%, 20%, etc. E_d is electricity demand.

Capacity Constraints on Power Plants:

The following constraints place an upper bound on electricity produced from each plant as well as ensuring that electricity production from fossil fuel plants is zero when no fuel is assigned to the plant. For fossil fuel plants, there is a minimum amount of electricity generated to satisfy. Total electricity generating during operational time should be less than or equal to maximum capacity. The constraints set places an upper bound on electricity produced from the different plants.

$$E_{f,j} \leq F_{\max} \cdot X_{f,j} \tag{5.7}$$

$$E_{rn} \leq RN_{\max} \cdot X_{rn} \tag{5.8}$$

$$E_p \leq P_{\max} \cdot X_p \tag{5.9}$$

$$E_{f,j} \geq L_f \cdot F_{\max} \cdot X_{f,j} \tag{5.10}$$

Carbon Emission Constraint:

In this constraint, CO_2 emissions must satisfy a CO_2 reduction target. $TotCO_2$ is total CO_2 emission from all the power plants, and Cre is the CO_2 reduction target. C_{now} is the current amount of CO_2 emission in millions of tonnes per year.

$$TotCO_2 = \sum_{f,j} C_{f,j} \cdot E_{f,j} + \sum_{p} C_p \cdot E_p \tag{5.11}$$

$$TotCO_2 \le (1 - Cre) \cdot C_{now} \tag{5.12}$$

Fuel Selection and Plant Shutdown:

For each fossil fuel plant, the process is either operating with one chosen fuel or shut down.

$$\sum_{j} X_{f,j} \le 1 \tag{5.13}$$

For stations in Lennox (LN), only natural gas is chosen as fuel; ln is the name of existing fossil fuel stations, which chose natural gas. This is the same as the other five stations use coal as fuel; *ng* means natural gas.

$$X_{\mathrm{ln},'ng'} = 1 \tag{5.14}$$

5.1.4 Screening, Assessment & Ranking of Alternatives

Two scenarios will be considered here. The first one is to consider an increase in aggregate demand growth without CO_2 emission constraints; this may be viewed as a business as usual scenario. Secondly, we will consider the same scenario with the added constraint of CO_2 emission reductions. In both cases, no *new technology* will be employed; only fuel balancing, fuel switching and new fossil fuel (coal and natural gas) generating stations will be used.

Scenario 1 – Aggregate Demand Growth without CO_2 Emission Constraints

In this scenario, no CO_2 emission constraints are considered, which means that Equation 5.12 is deleted from the model, while all the others keep same.

The base case load demand is 1.2058E8 (MWh). After optimization, the minimum total cost and amount of electricity generated from different types of power stations are presented in Table 5.1.

Table 5.1 Total Cost and Electricity Generation without CO_2 Emission Constraints, with Demand Growth, without *New Technologies*

Demand Growth	***TotCost*** **($/year)**	***TotE*** **(MWh)**	***CostE*** **¢/KWh**	***TotCO₂*** **(tonnes/year)**
Base Load	1.8665E+9	1.2058E+8	1.5479	3.6052E+7
1% Growth	1.9155E+9	1.2178E+8	1.5729	3.6938E+7
5% Growth	2.2239E+9	1.2661E+8	1.7565	4.1350E+7
10% Growth	2.5820E+9	1.3263E+8	1.9468	4.6661E+7
20% Growth	3.2031E+9	1.4469E+8	2.2138	5.2886E+7

The optimizer will minimize the objective function, Equation (5.1), by choosing the three alternatives (fuel balancing, fuel switching and new fossil fuel generating stations). Naturally, the total cost, *TotCost*, increases when the aggregate demand is increased; the increase in total cost increases by 72% when the aggregate demand increases by 20%. The increase in total energy, *TotE,* is the aggregate energy and reflects the increase in demand directly. The cost of energy also increases. At first, this may appear to be unclear, but it is due to the fact that the new generating stations that are being added are costly because of their capital cost; the existing fleet is assumed to be paid off and therefore the COE of base load fleet is a function of the operating cost only; if new generating capacity (with the same operating cost) is added, then the COE will increase. Finally, CO_2 emissions have increased due to the increased use of fossil fuel generating stations; CO_2 emissions increased by 47% when demand increased by 20% because there is no CO_2 emission constraint and additional load is added to the existing power stations to meet demand growth.

Table 5.2 Electricity Generation for Various Types of Power Stations without CO_2 Constraints, with Demand Growth, without *New Technologies*

Power Stations	Base Load (MWh)	1% Growth (MWh)	5% Growth (MWh)	10% Growth (MWh)	20% Growth (MWh)
Fossil Fuel	3.8899E+7	4.0105E+7	3.8043E+7	3.7186E+7	4.0105E+7
Nuclear	4.2319E+7	4.2319E+7	4.2319E+7	4.2319E+7	4.2319E+7
Renewable	3.9359E+7	3.9359E+7	3.9359E+7	3.9359E+7	3.9359E+7
New Coal	0	0	6.8854E+6	1.3771E+7	1.3771E+7
New NGCC	0	0	0	0	9.1389E+6

Table 5.2 shows electricity generation for various types of power generation. The electricity generation from renewable including nuclear remain constant. In order to meet the demand, more electricity is produced from the existing plants since the installed capacity of fossil fuel generating stations is enough to meet 20% growth. The detailed power station load distribution is shown in Table B.1 (Appendix B).

<u>Scenario 2 – Aggregate Demand Growth with CO_2 Emission Constraints</u>

Base Load Demand

The current CO_2 amount is 3.7338013E+7 tonnes, and one of the objectives is to minimize the cost of electricity, while satisfying CO_2 emission constraints.

First, base case load demand, which is 1.2058E8 (MWh), and 6%, 20%, and 40% CO_2 reduction were considered. In Tables 5.3 and 5.4, one can see the minimum total cost and amount of electricity generated in different kinds of power stations.

Table 5.3 Total Cost and Electricity Generation with CO_2 Constraints, Base Load Demand, without *New Technologies*

CO_2 Reduction	***TotCost* ($/year)**	***TotE* (MWh)**	***CostE* ¢/KWh**	***TotCO₂* (tonnes/year)**	***CostCO₂* ($/tonne)**
0%	1.8665E+9	1.2058E+8	1.5479	3.6052E+7	--------
6%	1.8893E+9	1.2058E+8	1.5668	3.5096E+7	23.85
20%	2.0334E+9	1.2058E+8	1.6863	2.9870E+7	27.57
40%	2.2190E+9	1.2058E+8	1.8403	2.2365E+7	24.73

At base load demand, the total cost increases when we need to reduce CO_2; the increase in total cost increases by 19% when CO_2 emission reduces to 40% from the current level of 3.7338E+7 tonnes/year at base load demand as shown in Table 5.3. The cost of electricity also increases by 19%. The maximum CO_2 reduction achieved is 40% even with the new fossil plants. The cost of CO_2 reduction ($/tonne) slightly increases after 20% CO_2 reduction due to fuel switching (retrofitting coal plants to natural gas). The cost of CO_2 reduction ($/tonne) is calculated by taking cost difference divided by CO_2 reduction.

Table 5.4 Electricity Generation for Various Types of Power Stations with CO_2 Constraints, Base Load Demand, without *New Technologies*

Power Stations	0% CO_2 Reduction (MWh)	6% CO_2 Reduction (MWh)	20% CO_2 Reduction (MWh)	40% CO_2 Reduction (MWh)
Fossil Fuel	3.8899E+7	3.8899E+7	3.8899E+7	3.8899E+7
Nuclear	4.2319E+7	4.2319E+7	4.2319E+7	4.2319E+7
Renewable E	3.9359E+7	3.9359E+7	3.9359E+7	3.9359E+7
New Coal	0	0	0	0
New NGCC	0	0	0	0

The details of electricity generation from various types of power stations are included in the Table B.2 (Appendix B). The electricity generation summary for various power stations is shown in Tables 5.4. The power generation from fossil fuel stations remains the same from 6% to 40% CO_2 reduction due to fuel balancing and switching load from lower efficient power stations to higher efficient power stations.

1% Growth in Base Demand

Next, a 1% aggregate load demand increase with 0%, 6%, 20% and 40% CO_2 reduction are considered. The optimal results are shown in Table 5.5 and 5.6.

Table 5.5 Total Cost and Electricity Generation with CO_2 Constraints, 1% Growth in Base Load Demand, without *New Technologies*

CO_2 Reduction	*TotCost* ($/year)	*TotE* (MWh)	*CostE* (¢/KWh)	*TotCO₂* (tonnes/year)	*CostCO₂* ($/tonne)
0%	1.9155E+9	1.2178E+8	1.5729	3.6938E+7	--------
6%	1.9696E+9	1.2178E+8	1.6173	3.4752E+7	24.75
20%	2.1235E+9	1.2178E+8	1.7437	2.9870E+7	31.52
40%	2.3310E+9	1.2178E+8	1.9141	2.2403E+7	27.79

The total cost and electricity cost with 1% growth increases by 22% when 40% CO_2 reduction is achieved at 3% higher than base load demand as shown in Table 5.5. The cost per tonne CO_2 reduction increases when CO_2 reduction increases. There is 27% cost increase from CO_2 reduction from 6% to 20% due to fuel balancing and switching power stations from lower efficiency to higher efficiency. However, the CO_2 reduction cost decreases by 13% from 20% to 40% CO_2 reduction because of a new NGCC power unit and switching of fuel from lower efficiency coal to natural gas.

Table 5.6 Electricity Generation for Various Types of Power Stations with CO_2 Constraints, 1% Growth in Base Load Demand, without *New Technologies*

Power Stations	0% CO_2 Reduction (MWh)	6% CO_2 Reduction (MWh)	20% CO_2 Reduction (MWh)	40% CO_2 Reduction (MWh)
Fossil Fuel	4.0105E+7	4.0105E+7	3.9152E+7	3.7769E+7
Nuclear	4.2319E+7	4.2319E+7	4.2319E+7	4.2319E+7
Renewable	3.9359E+7	3.9359E+7	3.9359E+7	3.9359E+7
New Coal	0	0	0	0
New NGCC	0	0	0	2.3359E+6

Table B.3 (Appendix B) shows the power stations load distribution. At 40% CO_2 reduction, the load is switched from existing lower efficiency power stations to a new NGCC power station and to higher efficiency existing power stations as represented in Table 5.6. A new NGCC power unit is added to meet additional demands and the CO_2 reduction target.

5% Growth in Base Demand

The load demand with 5% growth and 0%, 6%, 20% and 40% CO_2 reduction are considered respectively. The optimal results are shown in Tables 5.7 and 5.8.

Table 5.7 Total Cost and Electricity Generation with CO_2 Constraints, 5% Growth in Base Load Demand, without *New Technologies*

CO_2 Reduction	*TotCost* ($/year)	*TotE* (MWh)	*CostE* (¢/KWh)	*TotCO₂* (tonnes/year)	*CostCO₂* ($/tonne)
0%	2.2487E+9	1.2661E+8	1.7761	3.7338E+7	-------
6%	2.3021E+9	1.2661E+8	1.8183	3.5098E+7	23.84
20%	2.4349E+9	1.2661E+8	1.9231	2.9870E+7	25.40
40%	2.9074E+9	1.2661E+8	2.2963	2.2403E+7	63.28

The total cost increases by 30% when CO_2 reduction increases to 40%. The overall total cost and electricity cost increase trends are the same. At 40% CO_2 reduction, the CO_2 reduction cost ($/tonne) is significantly higher than at 6% and 20% CO_2 reduction as shown in Table 5.7 due to switching of load from existing plants to five new NGCC plants and fuel balancing in existing power stations.

Table 5.8 Electricity Generation for Various Types of Power Stations with CO_2 Constraints, 5% Growth in Base Load Demand, without *New Technologies*

Power Stations	0% CO_2 Reduction (MWh)	6% CO_2 Reduction (MWh)	20% CO_2 Reduction (MWh)	40% CO_2 Reduction (MWh)
Fossil Fuel	3.8550E+7	3.8934E+7	3.9186E+7	2.8347E+7
Nuclear	4.2319E+7	4.2319E+7	4.2319E+7	4.2319E+7
Renewable	3.9359E+7	3.9359E+7	3.9359E+7	3.9359E+7
New Coal	0	0	0	0
New NGCC	6.3779E+6	5.9941E+6	5.7418E+6	1.6581E+7

The details of electricity generation from various types of power stations are shown in Table B.4 (Appendix B). Five new NGCC power units are added to meet demands and the CO_2 reduction target. The optimizer shuts down or reduces load on lower efficiency power stations to higher efficiency power stations. The electricity generation from nuclear power stations and renewable remains the same. The optimal results are shown in Table 5.8.

10% Growth in Base Demand

Next, load demand with 10% growth and 6%, 20%, 40% CO_2 reduction are considered. The optimal results are shown in Tables 5.9 and 5.10.

Table 5.9 Total Cost and Electricity Generation with CO_2 Constraints, 10% Growth in Base Load Demand, without *New Technologies*

CO_2 Reduction	*TotCost* ($/year)	*TotE* (MWh)	*CostE* (¢/KWh)	*TotCO$_2$* (tonnes/year)	*CostCO$_2$* ($/tonne)
0%	2.6618E+9	1.3263E+8	2.0069	3.7338E+7	------
6%	2.7164E+9	1.3263E+8	2.0481	3.5098E+7	24.38
20%	2.8625E+9	1.3263E+8	2.1583	2.9582E+7	26.49
30%	3.0623E+9	1.3263E+8	2.3089	2.6137E+7	58.00

The total cost and cost of electricity increase by 15% when CO_2 reduces from 0% to 30% at 10% growth in based load demand. The cost per tonne CO_2 reduction increases significantly because the optimizer added five new NGCC power units to meet 10% growth demand and 30% CO_2 reduction as shown in Table 5.9. At 10% growth in base load demand, only up to 30% CO_2 reduction is achieved.

Table 5.10 Electricity Generation for Various Types of Power Stations with CO_2 Constraints, 10% Growth in Base Load Demand, without *New Technologies*

Power Stations	0% CO_2 Reduction (MWh)	6% CO_2 Reduction (MWh)	20% CO_2 Reduction (MWh)	30% CO_2 Reduction (MWh)
Fossil Fuel	3.8593E+7	3.8905E+7	4.0105E+7	3.4961E+7
Nuclear	4.2319E+7	4.2319E+7	4.2319E+7	4.2319E+7
Renewable	3.9359E+7	3.9359E+7	3.9359E+7	3.9359E+7
New Coal	0	0	0	0
New NGCC	1.2364E+7	1.2052E+7	1.0852E+7	1.5996E+7

The details of electricity generation from various types of power stations are shown in Table B.5 (Appendix B). Five new NGCC power units are added to meet demand and CO_2 reduction targets. The optimizer shuts down or reduces load on lower efficiency power stations to higher efficiency power stations. The electricity generation from nuclear power stations and renewable remains the same. The optimal results are shown in Table 5.10.

20% Growth in Base Demand

Finally, load demand with 20% growth and 0%, 6% and 20% CO_2 reduction are considered. The optimal results are shown in Tables 5.11 and 5.12.

Table 5.11 Total Cost and Electricity Generation with CO_2 Constraint, 20% Growth in Base Load Demand, without *New Technologies*

CO_2 Reduction	*TotCost* ($/year)	*TotE* (MWh)	*CostE* (¢/KWh)	*TotCO₂* (tonnes/year)	*CostCO₂* ($/tonne)
0%	3.5172E+9	1.4469E+8	2.4309	3.7080E+7	-----
6%	3.5684E+9	1.4469E+8	2.4662	3.5098E+7	25.83

The total cost and cost of electricity increase by 1.5% when CO_2 reduces from 0% to 6% at 20% growth in based load demand. The cost per tonne of CO_2 reduction reduces to $26/tonne because the optimizer added new NGCC power units to meet 20% growth demand and 6% CO_2 reduction as shown in the Table 5.11. At 20% growth in base load demand, only up to 6% CO_2 reduction is achieved. The growth is achieved by adjusting the capacity at higher efficiency power stations.

Table 5.12 Electricity Generation for Various Types of Power Stations with CO_2 Constraints, 20% Growth in Base Load Demand, without *New Technologies*

CO_2 Reduction	0% CO_2 Reduction (MWh)	6% CO_2 Reduction (MWh)
Fossil Fuel	4.0105E+7	4.0057E+7
Nuclear	4.2319E+7	4.2319E+7
Renewable	3.9359E+7	3.9359E+7
New Coal	0	0
New NGCC	2.2910E+7	2.2957E+7

The details of electricity generation from various types of power stations are shown in Table B.6 (Appendix B). Two new NGCC power units are added to meet demand and CO_2 reduction targets. The optimizer shuts down or reduces the load on lower efficiency power stations. The electricity generation from nuclear power stations and renewable remains same. The optimal results are shown in Table 5.12.

5.1.5 Sensitivity Analysis

Three scenarios are considered in coal and natural gas price. The costs of coal and natural gas are increased by 10%, 50% and 100%, while the electricity demand growth is 1%, 5%, 10%, 20% and carbon reduction requirement is 6%. At first, the fuel price increases by 10%. The optimal results are shown in Tables 5.13 and 5.14.

Table 5.13 Total Cost and Electricity Generation with 6% CO_2 Emissions for Various Demand Growths, 10% Fuel Price Increase, without *New Technologies*

Demand Growth	*TotCost* ($/year)	*TotE* (MWh)	*CostE* (¢/KWh)	*TotCO₂* (tonnes/year)
Base Load	1.8893E+9	1.2058E+8	1.5668	3.5096E+7
1% Growth	1.9696E+9	1.2178E+8	1.6173	3.4752E+7
5% Growth	2.3254E+9	1.2661E+8	1.8367	3.5098E+7
10% Growth	2.7633E+9	1.3263E+8	2.0835	3.5098E+7
20% Growth	3.6598E+9	1.4469E+8	2.5294	3.5098E+7

The total cost and cost of electricity increase by 2.5%, when fuel price increases by 10% and base load demand increases by 20%. The total CO_2 reduction remains 6%. The results are compared with Table 5.11. The total cost and cost electricity increase due to increase cost of fuel. The results are shown in Table 5.13.

Table 5.14 Electricity Generations for Various Types of Power Stations with 6% CO_2 Emissions, Various Demand Growths, 10% Fuel Price Increase, without *New Technologies*

Power Stations	Base Load (MWh)	1% Growth (MWh)	5% Growth (MWh)	10% Growth (MWh)	20% Growth (MWh)
Fossil Fuel	3.8899E+7	4.0105E+7	3.8934E+7	3.8905E+7	4.0057E+7
Nuclear	4.2319E+7	4.2319E+7	4.2319E+7	4.2319E+7	4.2319E+7
Renewable	3.9359E+7	3.9359E+7	3.9359E+7	3.9359E+7	3.9359E+7
New Coal	0	0	0	0	0
New NGCC	0	0	5.9941E+6	1.2052E+7	2.2957E+7

The details of load distribution of various types of power stations are shown in Table B.7 (Appendix B). Some of the lower efficiency power stations are shifted to higher efficiency power stations and new NGCC plants due to higher fuel prices as shown in Table 5.14.

In the next scenario, the fuel prices increase by 50% and the optimal results are shown in Tables 5.15 and 5.16.

Table 5.15 Total Cost and Electricity Generation with 6% CO_2 Emissions for Various Demand Growths, 50% Fuel Price Increase, without *New Technologies*

Demand Growth	*TotCost* ($/year)	*TotE* (MWh)	*CostE* (¢/KWh)	*TotCO₂* (tonnes/year)
Base Load	1.8893E+9	1.2058E+8	1.5668	3.5096E+7
1% Growth	1.9696E+9	1.2178E+8	1.6173	3.4752E+7
5% Growth	2.4271E+9	1.2661E+8	1.9170	3.5098E+7
10% Growth	2.9555E+9	1.3263E+8	2.2284	3.5098E+7
20% Growth	4.0260E+9	1.4469E+8	2.7825	3.5098E+7

The total cost and cost of electricity increase by 13%, when fuel price increases by 50% and base load demand increases by 20%. The increase in total cost and cost of electricity was due to increase in fuel price and the shifting of the power load from lower efficiency power stations to higher efficiency power stations, shutting down lower efficiency power stations and shifting load from existing power stations to the new NGCC power plants. The results are compared with Table 5.11. The total CO_2 reduction remains 6%. The results are shown in Table 5.15.

Table 5.16 Electricity Generations for Various Types of Power Stations with 6% CO_2 Emissions, Various Demand Growths, 50% Fuel Price Increase, without *New Technologies*

Power Stations	Base Load (MWh)	1% Growth (MWh)	5% Growth (MWh)	10% Growth (MWh)	20% Growth (MWh)
Fossil Fuel	3.8899E+7	3.4752E+7	3.9469E+7	3.9436E+7	4.0105E+7
Nuclear	4.2319E+7	4.2319E+7	4.2319E+7	4.2319E+7	4.2319E+7
Renewable	3.9359E+7	3.9359E+7	3.9359E+7	3.9359E+7	3.9359E+7
New Coal	0	0	0	0	6.3094E+6
New NGCC	0	0	5.4590E+6	1.1521E+7	4.9260E+6

The details of load distribution of various kinds of power stations are shown in Table B.8 (Appendix B). Some of the lower efficiency power stations are either shifted to higher efficiency power station or shutdown due to higher fuel prices. New NGCC plants are added as shown in Table 5.16.

In the last scenario, the fuel prices increase by 100% and the optimal results are shown in Tables 5.17 and 5.18.

Table 5.17 Total Cost and Electricity Generation with 6% CO_2 Emissions for Various Demand Growths, 100% Fuel Price Increase, without *New Technologies*

Demand Growth	***TotCost*** ($/year)	***TotE*** (MWh)	***CostE*** (¢/KWh)	***TotCO₂*** (tonnes/year)
Base Load	1.8893E+9	1.2058E+8	1.5668	3.5096E+7
1% Growth	1.9696E+9	1.2178E+8	1.6173	3.4752E+7
5% Growth	2.4823E+9	1.2661E+8	1.9606	3.4719E+7
10% Growth	3.0711E+9	1.3263E+8	2.3155	3.4599E+7
20% Growth	4.4158E+9	1.4469E+8	3.0519	3.5098E+7

The total cost and cost of electricity increase by 23.7, when fuel price increases by 100% and base load demand increases by 20%. The increase in total cost and cost of electricity was due to increase in fuel price and the shifting of the power load from lower efficiency power stations to higher efficiency power stations, shutting down lower efficiency power stations and shifting load from existing power stations to the new NGCC power plants. The total CO_2 reduction remains 6%. The results are shown in Table 5.17.

Table 5.18 Electricity Generation for Various Types of Power Stations with 6% CO_2 Emissions, Various Demand Growths, 100% Fuel Price Increase, without *New Technologies*

Power Stations	**Base Load (MWh)**	**1% Growth (MWh)**	**5% Growth (MWh)**	**10% Growth (MWh)**	**20% Growth (MWh)**
Fossil Fuel	3.8899E+7	4.0105E+7	4.0105E+7	4.0105E+7	4.0105E+7
Nuclear	4.2319E+7	4.2319E+7	4.2319E+7	4.2319E+7	4.2319E+7
Renewable	3.9359E+7	3.9359E+7	3.9359E+7	3.9359E+7	3.9359E+7
New Coal	0	0	3.4427E+6	1.0328E+7	6.3094E+6
New NGCC	0	0	1.3804E+6	5.2389E+5	1.6600E+7

The details of load distribution of various kinds of power stations are shown in Table B.9 (Appendix B). Some of the lower efficiency power stations are either shifted to higher efficiency power stations or shutdown due to higher fuel prices. New NGCC plants are added as shown in Table 5.17.

5.1.6 Evaluation of Results

Without CO_2 Emission Constraints

The cost of electricity is 1.5479 ¢/KWh at base load, which is the same as 0% CO_2 reduction in Scenario 2. The electricity cost increases by 43% along with CO_2 emissions as the base load increases to 20%. This is due to additional load to lower efficiency power stations in order to meet the increased demand.

With CO_2 Emission Constraints

The electricity cost versus CO_2 reduction for various aggregate demand growths without *new technologies* results from Tables 5.3, 5.5, 5.7.5.9 and 5.11 are shown in Figure 5.1.

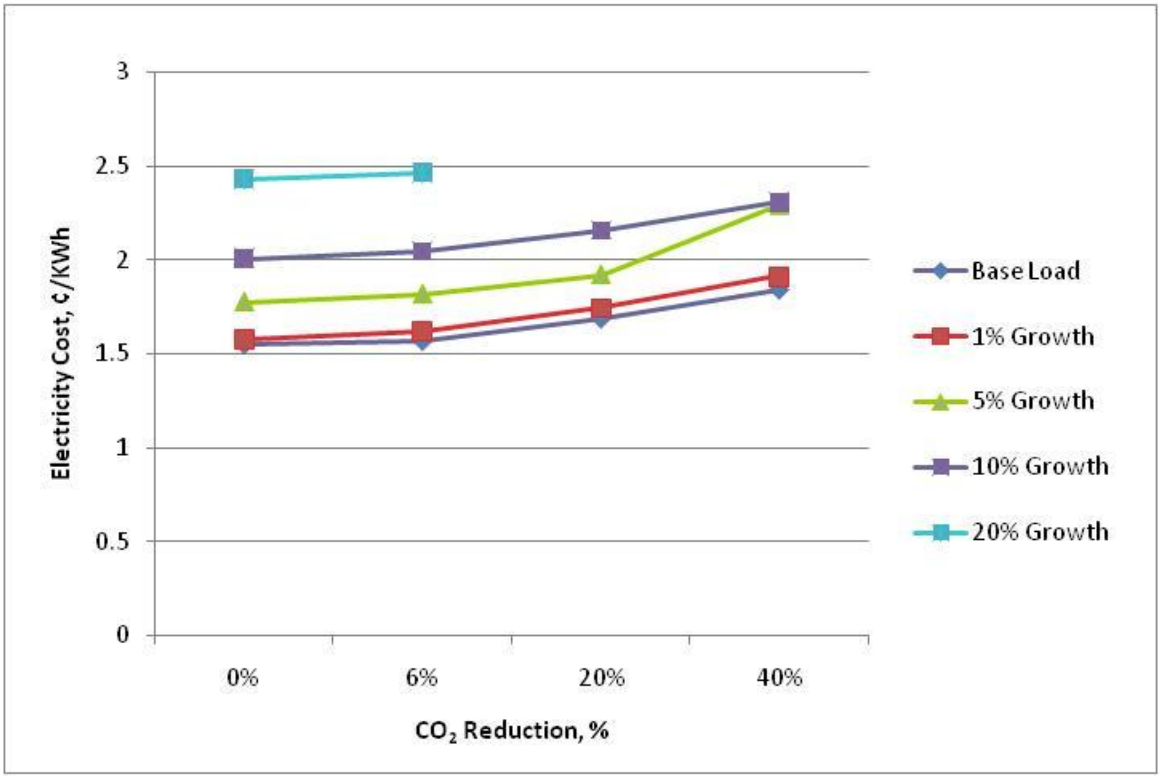


Figure 5.1 Electricity Cost vs. CO_2 Reduction for Various Aggregate Demand Growths without *New Technologies*

Electricity Cost: Electricity cost increases as demand growth increases. For 20% demand growth case, only 6% CO_2 reduction is achieved even with new plants like NGCC. The slope above 20% CO_2 reduction increases because for up to 20% reduction, only existing power plants (fossil fuel and renewable) are adjusted (fuel balancing), and for above 20%, new power plants are needed to satisfy demand requirement at 1% growth in base load demand. For 5%, 10%, and 20% increase in base load demand, the load on new power plnats increases at all CO_2 reduction levels.

The CO_2 reduction costs versus CO_2 reduction at various growth levels without *new technologies* results from Tables 5.3, 5.5, 5.7.5.9 and 5.11 are shown in Figure 5.2.

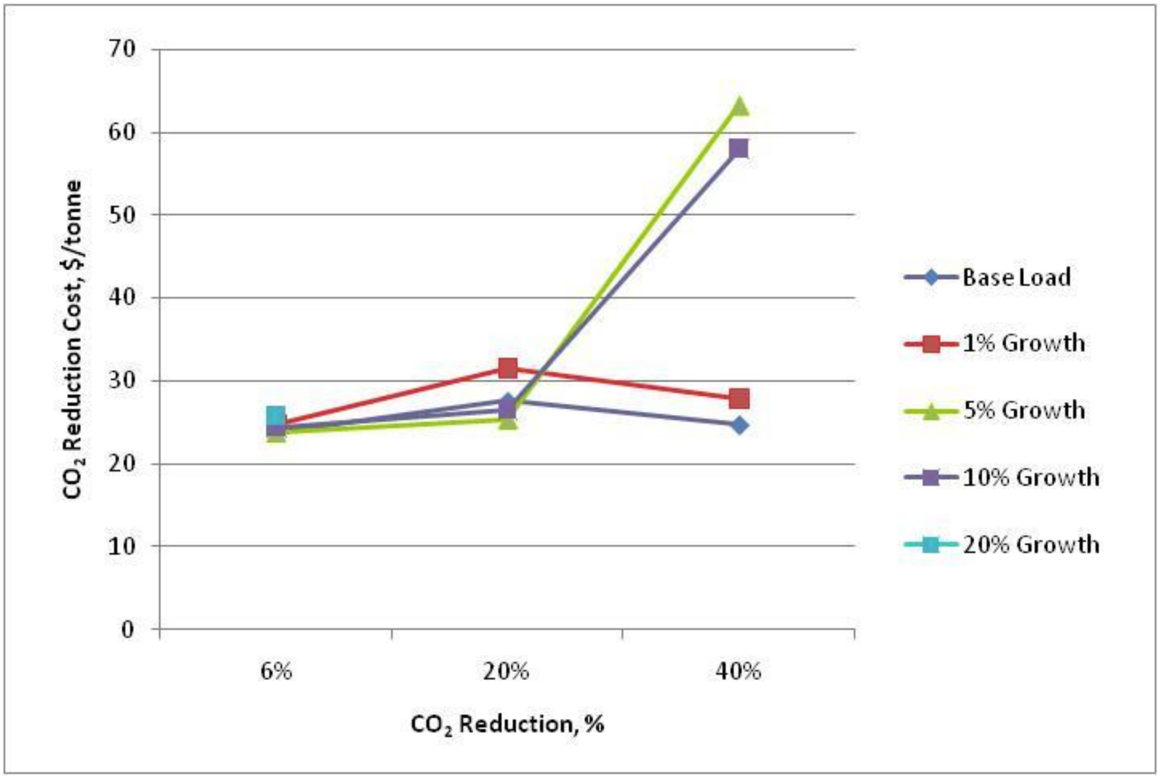


Figure 5.2 CO_2 Reduction Cost vs. CO_2 Reduction at Various Growth Levels without *New Technologies*

<u>CO_2 Reduction Cost</u>: Carbon reduction cost increases as demand growth increases. For 20% demand growth case, only 6% CO_2 reduction is achieved even with new plants. As new plants are added, cost of carbon reduction is higher than the cost of carbon reduction without new plants. The slope above 20% carbon reduction turns steep because above 20% new plants are selected as well in order to satisfy the demand requirement, namely 5%, 10%, and 10% demand growth as explained in Figure 5.2.

For base load demand, no new plants are needed for up to 40% carbon reduction and CO_2 reduction is achieved by fuel balancing. For 1% growth in base load demand, new plant is added at 40% CO2 reduction and for 5%, 10%, and 20% growth in base load demand, the new plnats are added at all CO2 reduction level. However, 60% carbon reduction cannot be achieved even with new plants as shown in Figure 5.3. The existing technologies are not efficient and produce more CO_2 as compared to *new technologies*. No new NGCC plants are added to satisfy CO_2 reduction requirements at base load demand as shown in Figure 5.3.

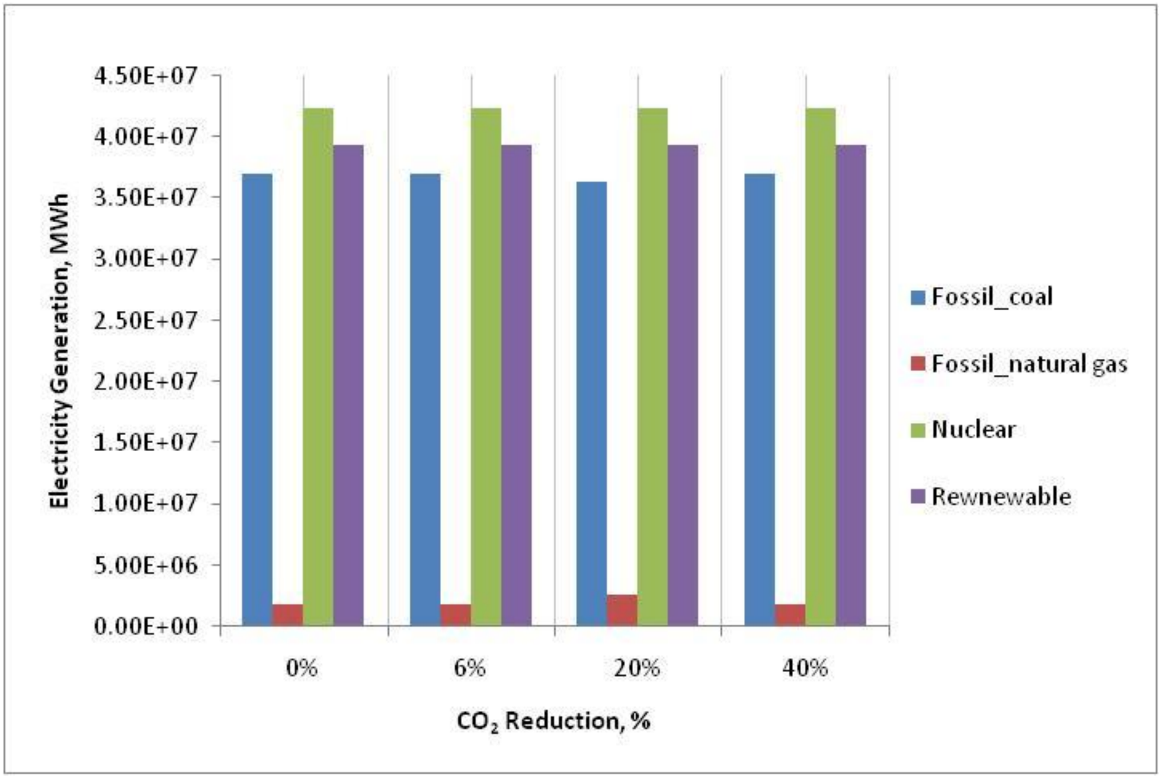


Figure 5.3 Electricity Generation Distributions vs. CO_2 Reduction at Base Load Demand without *New Technologies*

Electricity generation distribution of various power stations at 10% growth from Table 5.10 is shown in Figure 5.4.

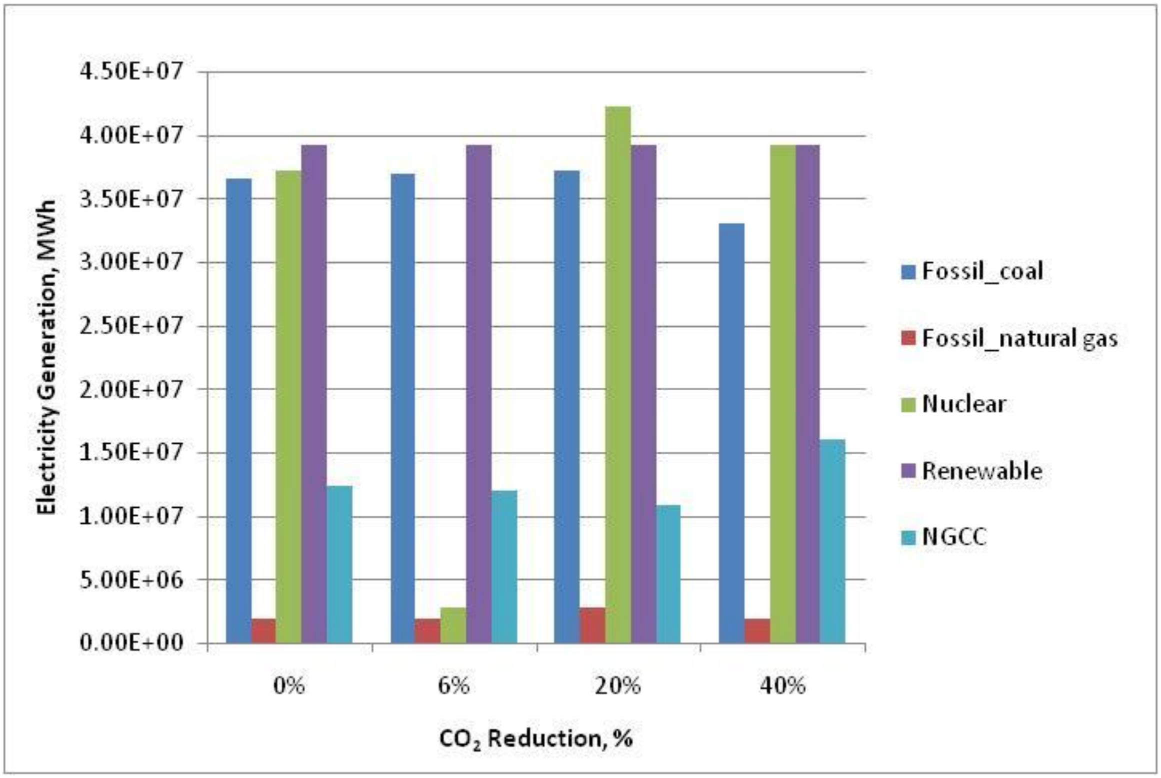


Figure 5.4 Electricity Generation Distributions vs. CO_2 Reduction at 10% Growth Demand without *New Technologies*

Electricity Generation Distribution: For base load demand, no new plants are needed up to 40% carbon reduction; even with the new plants, 60% reduction cannot be achieved. Some of the load from coal fossil power stations is shifted to new NGCC plants at all CO_2 reduction levels as shown in Figure 5.4.

For 1% increase in demand, no new plants are needed up to 20% carbon reduction. For 5%, and 20% increase in demand, new plants are needed at all CO_2 reduction levels. For based load demand, 1%, 5%, 10%, and 20% demand growth, even with new plants, 60% carbon reduction cannot be achieved. For 10% demand growth, up to 30% carbon reduction can be achieved with new plants. New NGCC plants are needed in all CO_2 reduction levels. For 20% demand growth case, new plants are needed up to 0% and 6% carbon reduction. Figure 5.4 shows the example of 10% growth.

The effect of fuel price increase on electricity cost for various aggregate demand growths from Tables 5.13, 5.15 and 5.17 is shown in Figure 5.5.

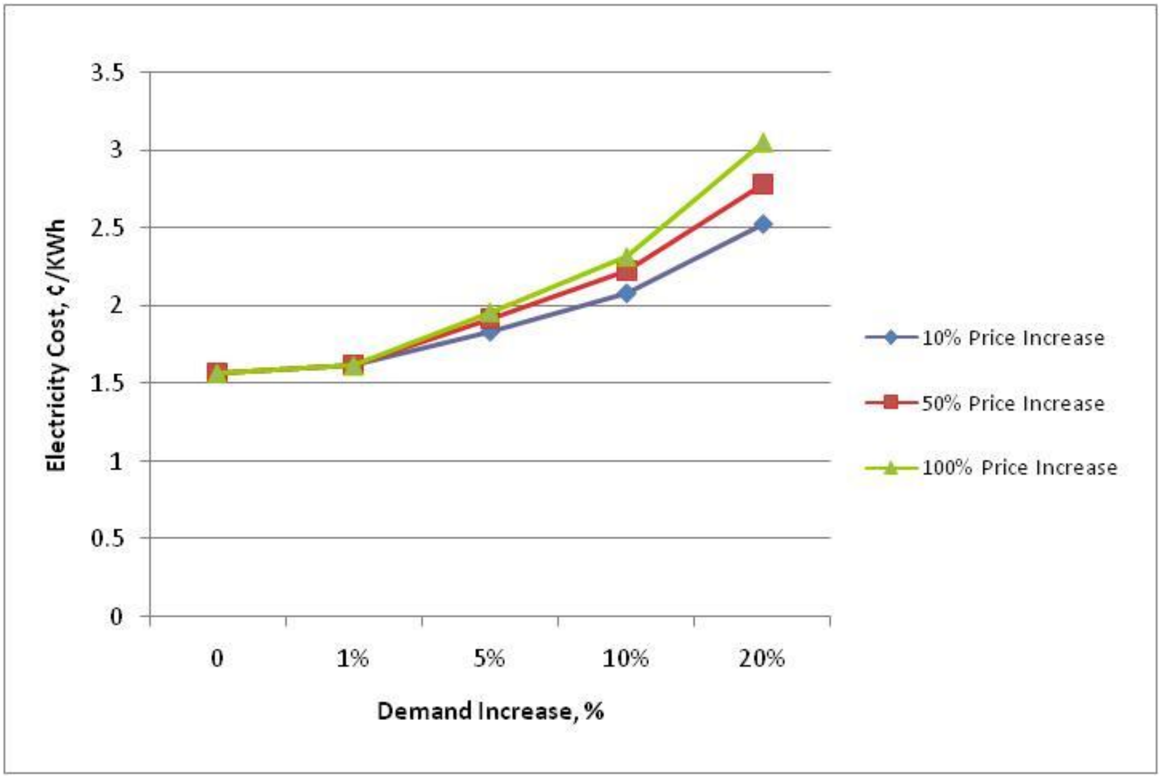


Figure 5.5 Effects of Coal and Natural Gas Price Increase on Electricity Cost for Various Aggregate Demand Growths without *New Technologies*

<u>Impact of Fuel Price Increase</u>: Electricity cost increases as fuel price increases. No matter how many percentages of fuel price increase, the slope of electricity cost stays almost the same. Figure 5.6 shows the trends. For 10% price increase, no new plants are needed up to 1% demand growth. 20% demand growth can be achieved with new plants. The total cost of electricity increases by 2.6% and 13% when fuel price increases by 10% and 50%, respectively, at 20% increase in base load demand and 6% CO_2 reduction.

The effect of 50% fuel price on electricity generation distribution from Table 5.16 is shown in Figure 5.6.

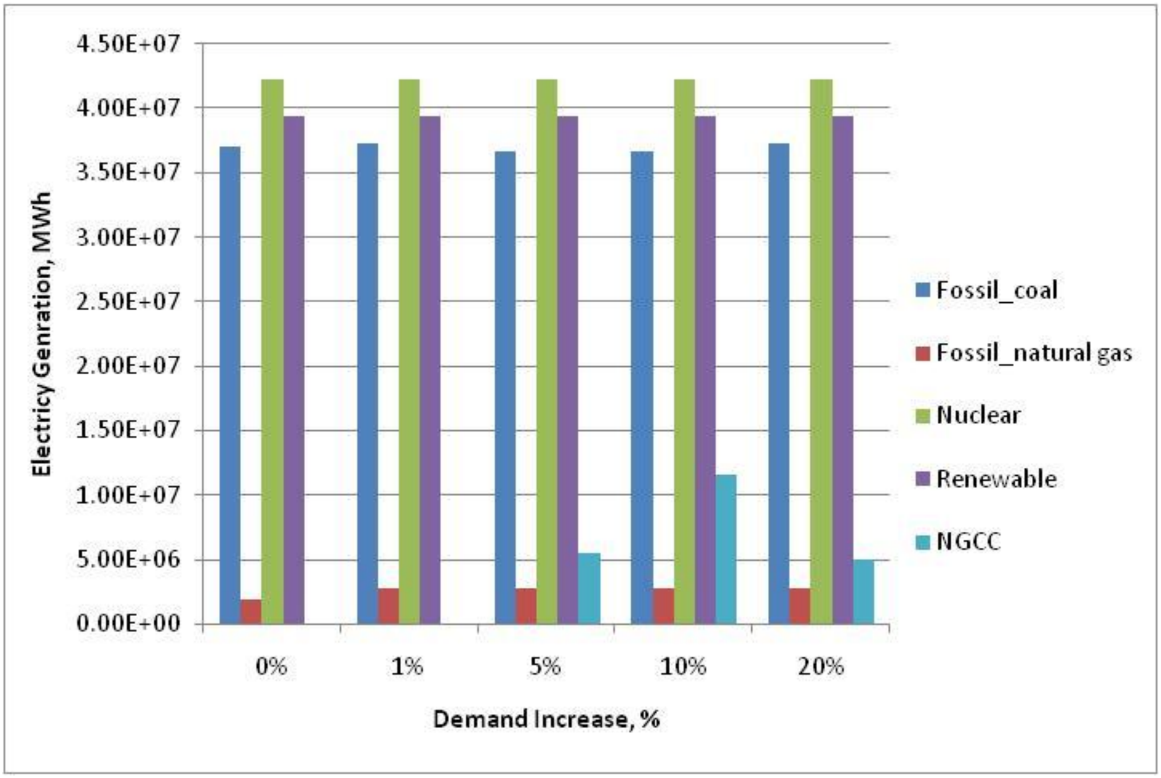


Figure 5.6 Electricity Generation Distributions at 50% Coal and Natural Gas Price Increase for Various Aggregate Demand Growths without *New Technologies*

For 50% fuel price increase, no new plants are needed up to 1% demand growth. 20% growth can be achieved with new plants, which is the same as the base case without fuel price increase, as shown in Figure 5.6. However, the load on coal fossil power stations increases as demand increases when fuel price increases by 50% as shown in Tables 5.15 and 5.16. New NGCC plants are added to satisfy the demand and CO_2 reduction requirements.

5.2 Step 2 - Improvement of Existing System with *New Technologies*

5.2.1 Development of Potential Alternatives

If the improvement in the process without the inclusion of *new technologies* is not sufficient to meet the demands of the business case, then one would expand the problem by allowing the inclusion of *new technologies* in the suite of potential alternatives. The inclusion of *new technologies* offers both potential improvements in the process and economics as well as increased risk due to the nature of *new technologies*.

This section will explore the inclusion of several *new technologies* along with existing technologies into the fleet of generating stations to both satisfy aggregate energy demand as well as meet various CO_2 emission reduction targets. *New technologies* that will be included in the solution include:

- Solar
- Wind
- IGCC with and without CO_2 capture
- NGCC with and without CO_2 capture
- CO_2 capture in existing PC and NGCC stations

In addition, power plants with existing technology include:

- Fossil fuel stations
- Renewable energy stations (nuclear, hydro and wind)
- PC station without carbon capture
- NGCC without carbon capture.

New Technology Power & Cost Distribution

Several *new technologies* power plants are considered. They are solar power plant; wind power plant; IGCC power plants IG1, IG2 and IG3; NGCC power plants NG1, NG2 and NG3; IGCC with carbon capture power plants IC1, IC2 and IC3; NGCC with carbon capture plants NC1, NC2 and NC3. The maximum capacity in *MWh/year* of each power plant is as following (Parsons Company; Fossil Energy Power Plant Desk Reference, 2007; Solar Energy Technologies Program, 2006; DOE Wind and Hydropower Technologies Program, 2006):

Table 5.19 Maximum Capacity of New Plants

	Maximum Capacity (MWh/year)
Solar	18,090,000
Wind	9,045,000
IG1	4,993,200
IG2	5,606,400
IG3	6,727,680
NG1	4,204,800
NG2	4,905,600
NG3	6,132,000
IC1	4,388,760
IC2	4,861,800
IC3	5,378,640
NC1	3,871,920
NC2	4,222,320
NC3	4,905,600

The capital and operating costs for *new technologies* are as below (Parsons Company; Fossil Energy Power Plant Desk Reference, 2007; Solar Energy Technologies Program, 2006; DOE Wind and Hydropower Technologies Program, 2006):

Table 5.20 Capital & Operating Costs of *New Technologies*

	Capital Cost ($/MW)	**Operating Cost ($/MWh)**
Solar	3,981,000	160
Wind	1,167,000	50
IG1	2,175,000	13.3
IG2	1,813,000	10.6
IG2	1,722,000	9
NG1	620,000	3
NG2	554,000	3.1
NG3	443,000	3.3
IC1	2,610,000	16.6
IC2	2,390,000	13.3
IC3	2,239,000	11.3
NC1	1,364,000	5.6
NC2	1,172,000	4.6
NC3	1,050,000	4.5

5.2.2 Modification of Model

In this section, the model is modified by adding *new technologies* into the previous model, namely solar, wind, IGCC, IGCC with capture, NGCC and NGCC with capture.

5.2.2.1 Objective Function

In this section, *new technologies* are added into the previous model, namely solar, wind, IGCC, IGCC with capture, NGCC and NGCC with capture. The capital cost and operating cost of *new technologies* are added. The capture and sequestration cost are also added. Other costs of existing technologies, such as capital cost (Equation 5.2), retrofit cost (Equation 5.3) and operating cost (Equation 5.4), are the same as for existing technologies as shown in Section 5.1.3.1.

$$\min TotCost = Capital + Retrofit + Operating + Capture + Seq + Capital_{new} + Operating_{new} \tag{5.15}$$

$$Capital_{new} = \sum_{new} C_{new} \cdot X_{new} \tag{5.16}$$

$$Operating_{new} = \sum_{new} O_{new} \cdot E_{new} \tag{5.17}$$

$$Capture = \sum_{f,j,k} Cc_f \cdot perC \cdot C_{f,j} \cdot \gamma_{f,j,k} \tag{5.18}$$

$$Seq = \sum_{p,sq} S_{p,sq} \cdot W_{f,sq} + \sum_{f,sq} S_{f,sq} \cdot \phi_{f,sq} \cdot C_{f,j} \cdot perC \tag{5.19}$$

5.2.2.2 Model Constraints

The minimization of the objective functions represented above is subjected to the following constraints. The *new technologies* constraints are added to the previous constraints of existing technologies as shown in Section 5.1.3.2. The capacity constraints on power plants for existing technologies (Equations 5.7 – 5.10) and fuel selection constraints (Equations 5.13 and 5.14) are the same as in Section 5.1.3.2. The total electricity generation which is generated by existing fossil fuel plants, renewable energy plants and new fossil plants must be equal to or greater than the desired electricity demand. The constraints set places an upper bound on electricity produced from the different plants. It also ensures that the electricity production from fossil fuel plants is zero when no fuel is assigned to the plants. Total electricity generating during operational time should be less than or equal to maximum capacity. For fossil fuel plants, there is a minimum amount of electricity generated to satisfy.

<u>Energy Balance/Demand Satisfaction</u>

$$TotE = \sum_{f,j} (E_{f,j} - \sum_{k} Ek_{f,j,k}) + \sum_{rn} E_{rn} + \sum_{p} E_p + \sum_{new} E_{new} \tag{5.20}$$

$$TotE \geq (1 + Ge) \cdot E_d \tag{5.21}$$

Capacity Constraints on Power Plants

$$E_{new} \leq New_{\max} \cdot X_{new} \tag{5.22}$$

$$Ek_{f,j,k} = C_f \cdot Ereq_f \cdot PerC \cdot \gamma_{f,j,k} \tag{5.23}$$

$$Ek_{f,j,k} \leq MaxC \cdot Z_{f,j,k} \tag{5.24}$$

Carbon Emission Constraints

CO_2 emissions must satisfy a CO_2 reduction target. TotCO_2 is total CO_2 emission from all power plants and Cre is the CO_2 reduction target. C_{now} is current amount of CO_2 emissions in millions of tonnes per year.

$$TotCO_2 = \sum_{f,j} C_{f,j} \cdot E_{f,j} + \sum_{p} C_p \cdot E_p - \sum_{f,j,k} C_{f,j} \cdot perC \cdot \gamma_{f,j,k} + \sum_{new} C_{new} \cdot E_{new} \tag{5.25}$$

$$TotCO_2 \leq (1 - Cre) \cdot C_{now} \tag{5.26}$$

Fuel Selection & Plant Shutdown

For each fossil fuel plants, the process is either operating with one chosen fuel or shutdown. For stations Lennox (LN), only natural gas is chosen as raw material. No capture process performs if fossil plant shutdown and there is no capture process for existing fossil natural gas plants. The sequestration procedure is needed if capture is applied. For identical plant, only one sequestration location will be selected. Big M is applied to constrained electricity amount for capture and sequestration procedures for existing fossil fuel plants linearization.

$$\sum_{k} Z_{f,j,k} \leq X_{f,j} \tag{5.27}$$

$$Z_{f,'ng',k} = 0 \tag{5.28}$$

$$\sum_{j,k} Z_{f,j,k} = \sum_{sq} W_{f,sq} \tag{5.29}$$

$$\sum_{sq} W_{f,sq} \leq 1 \tag{5.30}$$

$$\gamma_{f,j,k} \leq E_{f,j} \tag{5.31}$$

$$\gamma_{f,j,k} \geq E_{f,j} - M \cdot (1 - Z_{f,j,k}) \tag{5.32}$$

$$\gamma_{f,j,k} \le M \cdot Z_{f,j,k} \tag{5.33}$$

$$\phi_{f,sq} \le E_{f,j} \tag{5.34}$$

$$\phi_{f,sq} \ge E_{f,j} - M_{sq} \cdot (1 - W_{f,sq}) \tag{5.35}$$

$$\phi_{f,sq} \le M_{sq} \cdot W_{f,sq} \tag{5.36}$$

5.2.3 Screening, Assessment & Ranking of Alternatives

The current CO_2 amount is 3.7338013E+7 tonnes, and one of our objectives is to minimize cost, while reducing CO_2 emissions amount.

First, the base case load demand, which is 1.2058E8 (MWh), and 0%, 6%, 20%, 40% and 60% CO_2 reduction are considered. The minimum total cost and amount of electricity generated in different types of power stations are illustrated in Tables 5.21 and 5.22.

Table 5.21 Total Cost and Electricity Generation with CO_2 Constraints, Base Load Demand, with *New Technologies*

CO_2 Reduction	***TotCost* ($/year)**	***TotE* (MWh)**	***CostE* (¢/KWh)**	***TotCO₂* (tonnes/year)**
0%	1.8660E+9	1.2058E+8	1.5475	3.6058E+7
6%	1.8892E+9	1.2058E+8	1.5668	3.5098E+7
20%	2.0187E+9	1.2058E+8	1.6742	2.9870E+7
40%	2.2121E+9	1.2058E+8	1.8345	2.2403E+7
60%	2.7015E+9	1.2058E+8	2.2404	1.4935E+7

In Table 5.21, we can see the total cost and cost of electricity increase when CO_2 reduction increases at base load demand. The total cost of electricity increases as CO2 reduction increases. The increase is slightly less than without new technologies. This is because the *new technology* power stations are more efficient in terms of fuel usage and conversion. The operating cost is also lower than existing plants. It is explained in more detail in Section 5.2.5.

Table 5.22 Electricity Generation for Various Types of Power Stations with CO_2 Constraints, Base Load Demand, with *New Technologies*

Power Stations	0% CO_2 Reduction (MWh)	6% CO_2 Reduction (MWh)	20% CO_2 Reduction (MWh)	40% CO_2 Reduction (MWh)	60% CO_2 Reduction (MWh)
Fossil Fuel	3.8899E+7	3.8899E+7	3.7585E+7	3.7585E+7	2.3669E+7
Nuclear	4.2319E+7	4.2319E+7	4.2319E+7	4.2319E+7	4.2319E+7
Renewable E	3.9359E+7	3.9359E+7	3.9359E+7	3.9359E+7	3.9359E+7
New Coal	0	0	0	0	0
New NGCC	0	0	0	0	0
IGCC_NT	0	0	0	0	0
NGCC_ NT	0	0	0	0	5.0627E+6
IGCCcap_NT	0	0	0	0	0
NGCCcap_NT	0	0	0	0	7.7587E+6
Solar_NT	0	0	0	0	0
Wind_NT	0	0	1.3140E+6	1.3140E+6	2.4090E+6

The details of electricity generation from various types of power stations are included in Table B.10 (Appendix B). The optimizer adjusts the load on new power stations and existing fossil power stations based on their efficiency and operating cost as shown in Table 5.22. *New technology* power stations NGCC with and without capture and wind power station are added because lower costs and to satisfy CO_2 reduction levels. Solar power stations are not selected because of higher costs and availability conditions. 60% CO_2 reduction can be achieved with new technologies.

1% Growth in Base Load Demand

The base load demand with 1% growth and 0%, 6%, 20%, 40% and 60% CO_2 reduction are considered. The optimal results are shown in Tables 5.23 and 5.24.

Table 5.23 Total Cost and Electricity Generation with CO_2 Constraints, 1% Growth in Base Load Demand, with *New Technologies*

CO_2 Reduction	*TotCost* ($/year)	*TotE* (MWh)	*CostE* (¢/KWh)	*TotCO₂* (tonnes/year)
0%	1.9155E+9	1.2178E+8	1.5729	3.6938E+7
6%	1.9436E+9	1.2178E+8	1.5960	3.5098E+7
20%	2.0769E+9	1.2178E+8	1.7055	2.9870E+7
40%	2.2714E+9	1.2178E+8	1.8652	2.2403E+7
60%	2.7771E+9	1.2178E+8	2.2804	1.4935E+7

At 1% growth in base load demand, the trends for the costs are the same as shown in Table 5.22. The total cost and cost of electricity increases when CO_2 reduction increases at base load demand. The increase of cost is 3% less than electricity cost without new technologies. This is because the *new technology* power stations are more efficient in terms of fuel usage and conversion. The operating cost for selected *new technologies* power stations is also lower than for existing plants. It is explained in more detailed in the results section. There is an increase of 2 - 4% total cost every percent increase in demand depending on the CO_2 reduction level.

Table 5.24 Electricity Generation for Various Types of Power Stations with CO_2 Constraints, 1% Growth in Base Load Demand, with *New Technologies*

Power Stations	0% CO_2 Reduction (MWh)	6% CO_2 Reduction (MWh)	20% CO_2 Reduction (MWh)	40% CO_2 Reduction (MWh)	60% CO_2 Reduction (MWh)
Fossil Fuel	4.0105E+7	3.8791E+7	3.8791E+7	3.8791E+7	2.1055E+7
Nuclear	4.2319E+7	4.2319E+7	4.2319E+7	4.2319E+7	4.2319E+7
Renewable E	3.9359E+7	3.9359E+7	3.9359E+7	3.9359E+7	3.9359E+7
New coal	0	0	0	0	0
New NGCC	0	0	0	0	0
IGCC_NT	0	0	0	0	0
NGCC_ NT	0	0	0	0	1.2472E+7
IGCCcap_ NT	0	0	0	0	0
NGCCcap_ NT	0	0	0	0	4.1698E+6
Solar_NT	0	0	0	0	0
Wind_NT	0	1.3140E+6	1.3140E+6	1.3140E+6	2.4090E+6

The details of electricity generation from various types of power stations are included in Table B.11 (Appendix B). The optimizer adjusts the load on new technology power stations and existing fossil power stations based on their efficiency and operating cost as shown in Table 5.24. *New technology* power stations wind and NGCC with and without capture are added because of their higher efficiencies and lower operating costs.

5% Growth in Base Load Demand

Next, load demand with 5% growth and 0%, 6%, 20%, 40%, 60% CO_2 reduction are considered. The computational results are shown in Tables 5.25 and 5.26.

Table 5.25 Total Cost and Electricity Generation with CO_2 Constraint, 5% Growth in Based Load Demand, with *New Technologies*

CO_2 Reduction	***TotCost*** ($/year)	***TotE*** (MWh)	***CostE*** (¢/KWh)	***TotCO₂*** (tonnes/year)
0%	2.1779E+9	1.2661E+8	1.7202	3.7304E+7
6%	2.2261E+9	1.2661E+8	1.7582	3.5098E+7
20%	2.3601E+9	1.2661E+8	1.8641	2.9870E+7
40%	2.5773E+9	1.2661E+8	2.0356	2.2403E+7
60%	3.1921E+9	1.2661E+8	2.5212	1.4935E+7

At 5% growth in base load demand, the trends for the costs are the same as shown in Table 5.25. The total cost and cost of electricity increase when CO_2 reduction increases at base load demand. The increase of electricity cost is 13% less than cost without new technologies at 40% CO_2 reduction. This is because the *new technology* power stations are more efficient in terms of fuel usage and conversion. The operating cost of selected *new technology* power stations is also lower than for existing plants. It is explained in more detail in Section 5.2.2.

Table 5.26 Electricity Generation for Various Types of Power Stations with CO_2 Constraints, 5% Growth in Base Load Demand, with *New Technologies*

Power Stations	0% CO_2 Reduction (MWh)	6% CO_2 Reduction (MWh)	20% CO_2 Reduction (MWh)	40% CO_2 Reduction (MWh)	60% CO_2 Reduction (MWh)
Fossil Fuel	3.9444E+7	3.9107E+7	3.9092E+7	3.7182E+7	2.2219E+7
Nuclear	4.2319E+7	4.2319E+7	4.2319E+7	4.2319E+7	4.2319E+7
Renewable E	3.9359E+7	3.9359E+7	3.9359E+7	3.9359E+7	3.9359E+7
New Coal	0	0	0	0	0
New NGCC	0	0	0	0	0
IGCC_NT	0	0	0	0	0
NGCC_NT	4.1698E+6	3.4119E+6	3.4271E+6	5.1510E+6	2.2219E+7
IGCCcap_NT	0	0	0	0	0
NGCCcap_NT	0	0	0	0	1.1050E+7
Solar_NT	0	0	0	1.8615E+5	0
Wind_NT	1.3140E+6	2.4090E+6	2.4090E+6	2.4090E+6	2.4090E+6

The details of electricity generation from various types of power stations are included in Table B.12 (Appendix B). The optimizer adjusts the load on new technology NGCC with and without CO_2 capture, solar, and wind power stations and existing fossil power stations based on their efficiency and operating cost as shown in Table 5.26. *New technology* power stations wind and NGCC with and without capture are added because of their lower costs and to satisfy CO_2 reduction levels.

10% Growth in Base Load Demand

Next, load demand with 10% growth and 0%, 6%, 20%, 40%, 60% CO_2 reductions are considered. The computational results are shown in Tables 5.27 and 5.28.

Table 5.27 Total Cost and Electricity Generation with CO_2 Constraints, 10% Growth in Base Load Demand, with *New Technologies*

CO_2 Reduction	*TotCost* ($/year)	*TotE* (MWh)	*CostE* (¢/KWh)	*TotCO₂* (tonnes/year)
0%	2.5249E+9	1.3263E+8	1.9037	3.7338E+7
6%	2.5824E+9	1.3263E+8	1.9471	3.5098E+7
20%	2.7168E+9	1.3263E+8	2.0484	2.9870E+7
40%	3.0067E+9	1.3263E+8	2.2670	2.2403E+7
60%	3.6759E+9	1.3263E+8	2.7715	1.4935E+7

At 10% growth in base load demand, the trends for the costs are the same as shown in Table 5.27. The total cost and cost of electricity increase when CO_2 reduction increases at base load demand. The electricity cost is 5.4% less than electricity cost without new technologies at 20% CO_2 reduction. This is because the *new technology* power stations and more efficient in terms of fuel usage and conversion. The operating cost of selected *new technology* power stations is also lower than for existing plants. The new technologies NGCC with and without CO_2 capture, IGCC with CO_2 capture, wind, and solar power stations are added to lower the cost and to satisfy CO_2 reduction levels. This is explained in more detail in Section 5.2.2.

Table 5.28 Electricity Generation for Various Types of Power Stations with CO_2 Constraints, 10% growth in Base Load Demand, with *New Technologies*

Power Stations	0% CO_2 Reduction (MWh)	6% CO_2 Reduction (MWh)	20% CO_2 Reduction (MWh)	40% CO_2 Reduction (MWh)	60% CO_2 Reduction (MWh)
Fossil Fuel	3.9166E+7	3.9166E+7	3.9186E+7	3.5621E+7	1.9852E+7
Nuclear	4.2319E+7	4.2319E+7	4.2319E+7	4.2319E+7	4.2319E+7
Renewable E	3.9359E+7	3.9359E+7	3.9359E+7	3.9359E+7	3.9359E+7
New Coal	0	0	0	0	0
New NGCC	0	0	0	0	0
IGCC_NT	0	0	0	0	0
NGCC_NT	9.3820E+6	9.3820E+6	9.3615E+6	8.7570E+6	1.2888E+7
IGCCcap_NT	0	0	0	0	4.5718E+6
NGCCcap_NT	0	0	0	4.1698E+6	1.1050E+7
Solar_NT	0	0	0	0	1.8615E+5
Wind_NT	2.4090E+6	2.4090E+6	2.4090E+6	2.4090E+6	2.4090E+6

The details of electricity generation from various types of power stations are included in Table B.13 (Appendix B). The Optimizer adjusts the load on new technology power stations, wind and solar power stations, and existing fossil power stations based on their efficiency and operating cost as shown in Table 5.28. *New technology* power stations wind, solar, NGCC with and without capture, and IGCC with CO_2 capture are added because of their higher efficiencies, lower operating costs, and CO_2 emissions

20% Growth in Base Load Demand

Finally, load demand with 20% growth and 0%, 6%, 20%, 40%, 60% CO_2 reduction are considered. The computational results are shown in Tables 5.29 and 5.30.

Table 5.29 Total Cost and Electricity Generation with CO_2 Constraints, 20% Growth in Base Load Demand, with *New Technologies*

CO_2 Reduction	*TotCost* ($/year)	*TotE* (MWh)	*CostE* (¢/KWh)	*TotCO₂* (tonnes/year)
0%	3.3341E+9	1.4469E+8	2.3043	3.7338E+7
6%	3.3918E+9	1.4469E+8	2.3442	3.5098E+7
20%	3.5282E+9	1.4469E+8	2.4385	2.9870E+7
40%	3.9889E+9	1.4469E+8	2.7569	2.2403E+7
60%	4.8025E+9	1.4469E+8	3.3192	1.4935E+7

At 20% growth in base load demand, the trends for the costs are the same as shown in Table 5.29. The total cost and cost of electricity increase when CO_2 reduction increases at base load demand. The electricity cost is 5.2% less than electricity cost without new technologies at 6% CO_2 reduction.This is because the *new technology* power stations are more efficient in terms of fuel usage and conversion. The new technologies NGCC with and without CO_2 capture, IGCC with CO_2 capture, wind, and solar power stations are added to lower the cost and to satisfy CO_2 reduction levels. The operating cost of selected *new technology* power stations is also lower than for existing plants. This is explained in more detailed in evaluation of results section.

Table 5.30 Electricity Generation for Various Types of Power Stations with CO_2 Constraints, 20% Growth in Base Load Demand, with *New Technologies*

Power Stations	0% CO_2 Reduction (MWh)	6% CO_2 Reduction (MWh)	20% CO_2 Reduction (MWh)	40% CO_2 Reduction (MWh)	60% CO_2 Reduction (MWh)
Fossil Fuel	3.9359E+7	3.9157E+7	3.9189E+7	3.3766E+7	1.8744E+7
Nuclear	4.2319E+7	4.2319E+7	4.2319E+7	4.2319E+7	4.2319E+7
Renewable E	3.9359E+7	3.9359E+7	3.9359E+7	3.9359E+7	3.9359E+7
New Coal	0	0	0	0	0
New NGCC	0	0	0	0	0
IGCC_NT	0	0	0	0	0
NGCC_NT	1.2956E+7	1.2956E+7	1.2956E+7	1.1658E+7	1.2252E+7
IGCCcap_NT	0	0	0	4.1325E+6	8.7044E+6
NGCCcap_NT	0	0	0	1.1050E+7	1.1050E+7
Solar_NT	0	0	0	0	0
Wind_NT	2.4090E+6	2.4090E+6	2.4090E+6	2.4090E+6	2.4090E+6

The details of electricity generation from various types of power stations are included in Table B.14 (Appendix B). The optimizer adjusts the load on new technology power stations and existing fossil power stations based on their efficiency and operating cost as shown in Table 5.30. *New technology* power stations IGCC with CO_2 capture , wind, solar, and NGCC with and without capture are added because of their higher efficiencies and lower operating costs and to satisfy CO_2 reduction levels.

5.2.4 Sensitivity Analysis

Three scenarios for the cost of fuels are considered. The fuel costs are increased to 10% and 100% respectively, while the electricity demand growth is 1%, 5%, 10%, 20% and carbon reduction requirement is 6%.

In the first scenario, the fuel price of coal and natural gas increase by 10%. The results are included in Tables 5.31 and 5.32.

Table 5.31 Total Cost and Electricity Generation with 6% CO_2 Emissions for Various Demand Growths, 10% Fuel Price Increase with *New Technologies*

Demand Growth	*TotCost* ($/year)	*TotE* (MWh)	*CostE* (¢/KWh)	*TotCO₂* (tonnes/year)
Base Load	1.8892E+9	1.2058E+8	1.5668	3.5098E+7
1% Growth	1.9436E+9	1.2178E+8	1.5960	3.5098E+7
5% Growth	2.2261E+9	1.2661E+8	1.7582	3.5098E+7
10% Growth	2.5824E+9	1.3263E+8	1.9471	3.5098E+7
20% Growth	3.4128E+9	1.4469E+8	2.3587	3.5098E+7

The total cost and cost of electricity increase by 0.62%, when fuel price increases by 10% and base load demand increases by 20%. The increment in total cost and cost of electricity are lower than in existing technologies, which is 2.6% increase in existing power stations. The *new technologies* are more efficient and consume less fuel to produce the same amount of power. The impact of fuel price is slightly lower than existing technologies because of wind and solar power stations.. The total CO_2 reduction remains 6%. The results are shown in Table 5.31.

Table 5.32 Electricity Generation for Various Types of Power Stations with 6% CO_2 Emissions, Various Demand Growths, 10% Fuel Price Increase, with *New Technologies*

Power Stations	Base Load (MWh)	1% Growth (MWh)	5% Growth (MWh)	10% Growth (MWh)	20% Growth (MWh)
Fossil Fuel	3.8899E+7	3.8791E+7	3.9107E+7	3.9166E+7	3.9976E+7
Nuclear	4.2319E+7	4.2319E+7	4.2319E+7	4.2319E+7	4.2319E+7
Renewable E	3.9359E+7	3.9359E+7	3.9359E+7	3.9359E+7	3.9359E+7
New Coal	0	0	0	0	0
New NGCC	0	0	0	0	3.3183E+6
IGCC_NT	0	0	0	0	0
NGCC_NT	0	0	3.4119E+6	9.3820E+6	1.2956E+7
IGCCcap_NT	0	0	0	0	0
NGCCcap_NT	0	0	0	0	4.1698E+6
Solar_NT	0	0	0	0	1.8615E+5
Wind_NT	0	1.3140E+6	2.4090E+6	2.4090E+6	2.4090E+6

The details of load distribution of various kinds of power stations are shown in Table B.15 (Appendix B). Some of the lower efficiency power stations are shifted to higher efficiency power stations. Electricity generation loads are added in new IGCC with CO_2 capture, wind, and NGCC with and without capture plants due to higher fuel prices as shown in Table 5.32.

In the next scenario, the fuel prices increase by 50%, and the results are represented in Tables 5.33 and 5.34.

Table 5.33 Total Cost and Electricity Generation with 6% CO_2 Emissions for Various Demand Growths, 50% Fuel Price Increase and with *New Technologies*

Demand Growth	*TotCost* ($/year)	*TotE* (MWh)	*CostE* (¢/KWh)	*TotCO$_2$* (tonnes/year)
Base Load	1.8892E+9	1.2058E+8	1.5668	3.5098E+7
1% Growth	1.9436E+9	1.2178E+8	1.5960	3.5098E+7
5% Growth	2.2261E+9	1.2661E+8	1.7582	3.5098E+7
10% Growth	2.5824E+9	1.3263E+8	1.9471	3.5098E+7
20% Growth	3.4178E+9	1.4469E+8	2.3622	3.5098E+7

The total cost and cost of electricity increase by 0.5%, when fuel price increases by 50% and base load demand increases by 20%. The increment in total cost and cost of electricity are lower than in existing technologies, which is 12.8% increase in existing power stations. The explanation is the same as given in Table 5.31. The total CO_2 reduction remains 6%. The results are shown in Table 5.33.

Table 5.34 Electricity Generation for Various Types of Power Stations with 6% CO_2 Emissions, Various Demand Growths, 50% Fuel Price Increase, with *New Technologies*

Power Stations	Base Load (MWh)	1% Growth (MWh)	5% Growth (MWh)	10% Growth (MWh)	20% Growth (MWh)
Fossil Fuel	3.8899E+7	3.8791E+7	3.9107E+7	3.9166E+7	3.9891E+7
Nuclear	4.2319E+7	4.2319E+7	4.2319E+7	4.2319E+7	4.2319E+7
Renewable E	3.9359E+7	3.9359E+7	3.9359E+7	3.9359E+7	3.9359E+7
New Coal	0	0	0	0	0
New NGCC	0	0	0	0	0
IGCC_NT	0	0	0	0	0
NGCC_NT	0	0	3.4119E+6	9.3820E+6	1.2956E+7
IGCCcap_NT	0	0	0	0	0
NGCCcap_NT	0	0	0	0	7.7587E+6
Solar_NT	0	0	0	0	0
Wind_NT	0	1.3140E+6	2.4090E+6	2.4090E+6	2.4090E+6

The details of load distribution of various kinds of power stations are shown in Table B.16 (Appendix B). Some of the lower efficiency power stations are shifted to higher efficiency power stations. Electricity generation loads are added in new wind and NGCC with and without capture plants due to higher fuel prices as shown in Table 5.34. *New technology* wind and NGCC have lower operating costs and CO_2 emissions..

In the last scenario, the fuel prices increase by 100% and the results are represented in Tables 5.35 and 5.36.

Table 5.35 Total Cost and Electricity Generation with 6% CO_2 Emissions for Various Demand Growths, 100% Fuel Price Increase, with *New Technologies*

Demand Growth	*TotCost* ($/year)	*TotE* (MWh)	*CostE* (¢/KWh)	*TotCO₂* (tonnes/year)
Base Load	1.8892E+9	1.2058E+8	1.5668	3.5098E+7
1% Growth	1.9436E+9	1.2178E+8	1.5960	3.5098E+7
5% Growth	2.3384E+9	1.2661E+8	1.8469	3.5098E+7
10% Growth	2.8807E+9	1.3263E+8	2.1720	3.5098E+7
20% Growth	4.0479E+9	1.4469E+8	2.7976	3.5098E+7

The total cost and cost of electricity increase by 19.3%, when fuel price increases by 50% and base load demand increases by 20%. The increment in total cost and cost of electricity are slightly lower than in existing technologies, which is 23.8% increase in existing power stations. The explanation is the same as given in Table 5.231. The total cost and cost of electricity increase as we increase fuel price. However, in *new technology* power stations, the total cost and cost of electricity increase less than existing technologies because of efficiency and wind power stations when the fuel price is increased. This is also probably because the load is shifted from the existing coal power station to the new natural gas station and wind power stations. The total CO_2 reduction remains 6%. The results are shown in Table 5.35.

Table 5.36 Electricity Generation for Various Types of Power Stations with 6% CO_2 Emissions, Various Demand Growths, 100% Fuel Price Increase, with *New Technologies*

Power Stations	Base Load (MWh)	1% Growth (MWh)	5% Growth (MWh)	10% Growth (MWh)	20% Growth (MWh)
Fossil Fuel	3.8899E+7	3.8791E+7	3.9839E+7	3.9992E+7	4.0105E+7
Nuclear	4.2319E+7	4.2319E+7	4.2319E+7	4.2319E+7	4.2319E+7
Renewable E	3.9359E+7	3.9359E+7	3.9359E+7	3.9359E+7	3.9359E+7
New Coal	0	0	0	0	0
New NGCC	0	0	0	0	0
IGCC_NT	0	0	0	5.7185E+6	1.0484E+7
NGCC_NT	0	0	0	0	3.1773E+6
IGCCcap_NT	0	0	0	0	0
NGCCcap_NT	0	0	0	0	0
Solar_NT	0	0	0	0	0
Wind_NT	0	1.3140E+6	2.4090E+6	2.4090E+6	2.4090E+6

The details of load distribution of various kinds of power stations are shown in Table B.17 (Appendix B). Some of the lower efficiency power stations are shifted to higher efficiency power stations. Electricity generation loads are added in new wind power station and NGCC with and without capture plants due to higher fuel prices as shown in Table 5.36. *New technology* wind and NGCC are more efficient and they have lower operating costs and CO_2 emissions.

5.2.5 Evaluation of Results

Electricity cost versus CO_2 reduction levels for various increases in aggregate electricity demand is plotted from Tables 5.23, 5.25, 5.27, 5.29 and 5.31 and is shown in Figure 5.7.

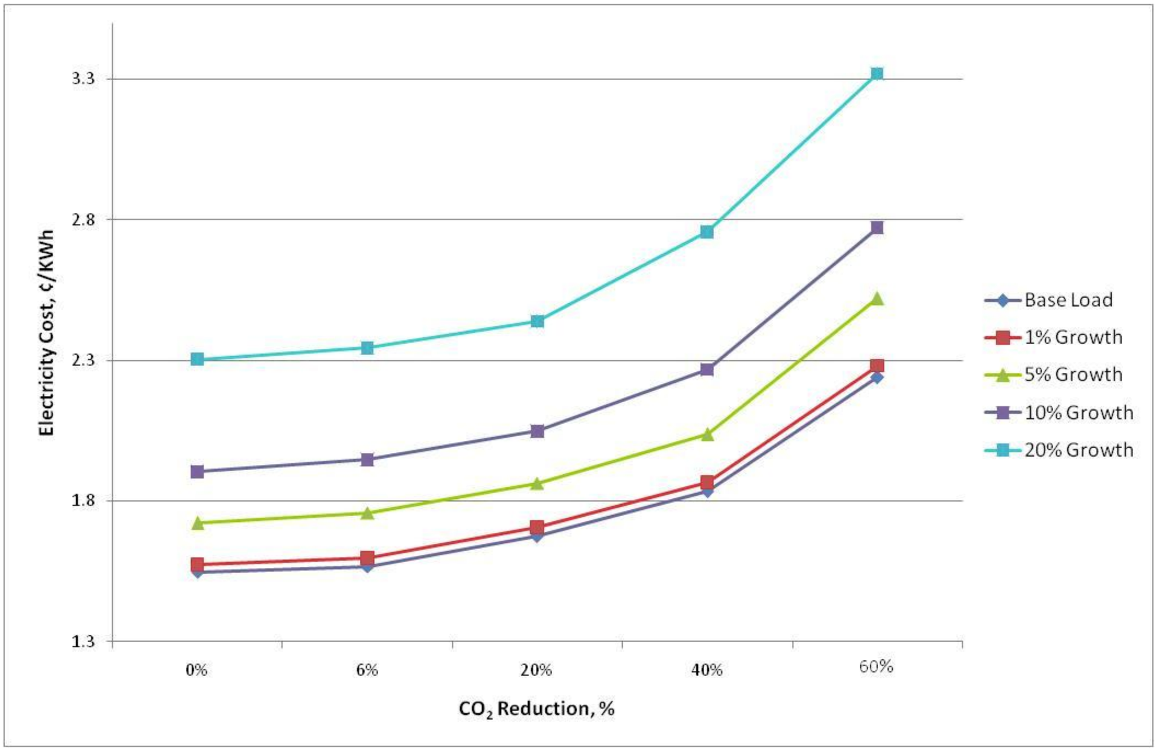


Figure 5.7 Electricity Cost vs. CO_2 Reduction at Various Increases in Aggregate Electricity Demand Growths with *New Technologies*

Electricity Cost & CO_2 Reduction: Electricity cost (¢/KWh) increases as demand increases and has the same trends with various demand requirements. With *new technologies*, 60% CO_2 reduction can be achieved. Electricity cost increases as CO_2 reduction requirements increase as explained in Figure 5.7. There is a sharp increase in curve after 20% CO_2 reduction because more new technology plants are added to satisfy CO_2 reduction requirements.

CO_2 Reduction Cost: The total electricity cost increases with the CO_2 reduction levels. The load distribution mix shows that the *new technologies* along with capture compensate control the CO_2 reduction level. Therefore, 60% CO_2 reduction can be achieved with *new technologies*.

Efficiency Comparison between New & Existing Technologies: It is assumed that capital cost of the existing zero or the capital cost is paid off. The following is the illustration of comparison between new and existing technologies:

Total cost = Capital cost + Operating cost

Existing Technology (Hashim, 2005)

Capital cost = 0

Operating cost range, Coal: \$17 – 46/MWh

Natural gas: \$26 – 46/MWh

Total cost = Capital Cost + Operating Cost

Total cost = 0 + 25 (average) = \$25/MWh for coal

= 0+29 = \$29/MWh for natural gas

Emissions range: 0.9386 – 1.023 tonnes/MWh for coal

: 0.5631 – 0.6138 tonne/MWh for natural gas

New Technology (Parsons, DOE/NETL – 2007/1282)

Capital cost: IGCC w/o capture, \$10.35/MWh

: IGCC w/capture, \$13.65/MWh

: NGCC w/o capture, \$3.162/MWh

: NGCC w/capture, \$6.69/MWh

Operating cost: IGCC w/o capture, \$11/MWh

: IGCC w/capture, \$13.5/MWh

: NGCC w/o capture, \$3/MWh

: NGCC w/capture, \$5/MWh

Emissions: IGCC w/o capture, 0.4 tonne/MWh

: IGCC w/capture, 0.04 tonne/MWh

: NGCC w/o capture, 0.2 tonne/MWh

: NGCC w/capture, 0.02 tonne/MWh

Total cost = 10.35+11 = \$21/MWh for IGCC w/o capture

= 13.65+13.5 = \$27/MWh for IGCC w/capture

= 3.162+3 = \$6/MWh for NGCC w/o capture

= 6.69 + 5 = $11.69/MWh for NGCC w/capture

It seems from the above efficiency data that the *new technology* power stations are more economical to operate and more efficient than existing technology power stations.

The electricity generation distribution versus CO_2 reduction at base load with *new technologies* is derived from Table 5.24 is shown in Figure 5.8. Figure 5.9 shows the load distribution with *new technologies* at base load demand and 10% growth in base load demand, which plotted from Table 5.30.

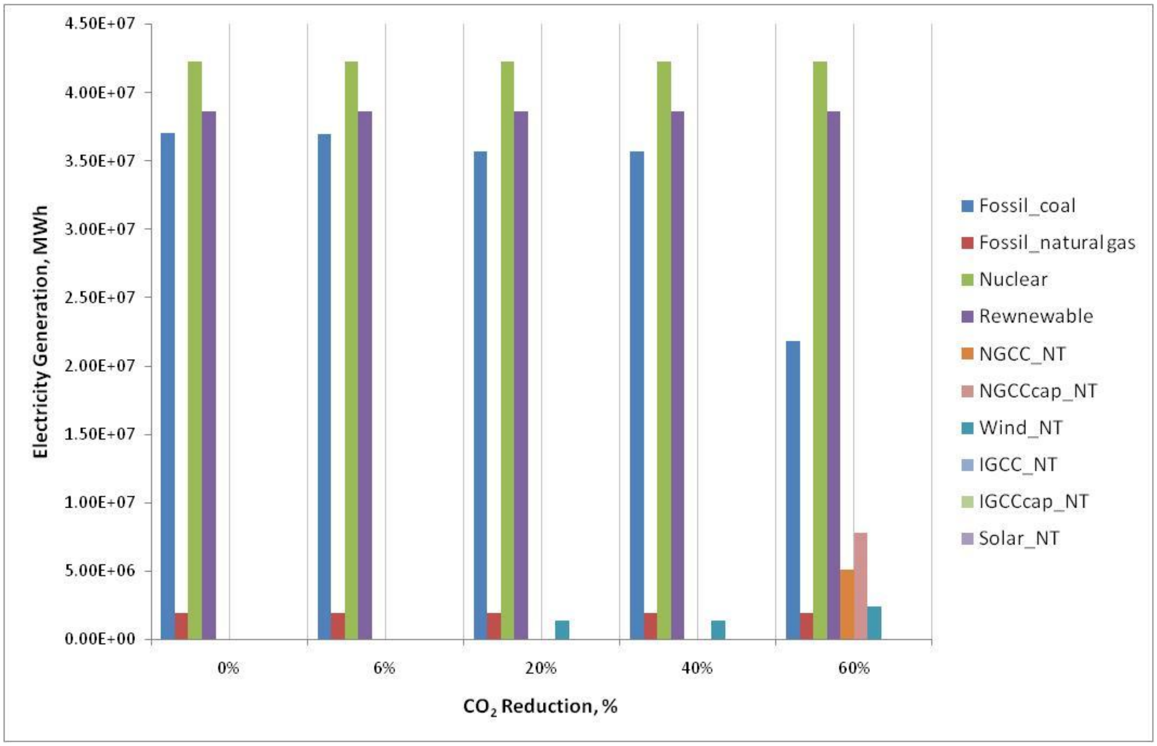


Figure 5.8 Electricity Generation Distributions vs. CO_2 Reduction at Base Load Demand with *New Technologies*

<u>Load Distribution at Various CO_2 Reductions</u>: For base load, the *new technologies* wind and NGCC with and without capture are selected at 60% CO_2 reduction scenarios.. Wind is selected, and it increases as CO_2 reduction increases from 20% to 60% CO_2 reduction. Renewable and nuclear plants load remain same in all scenarios. The load on existing fossil plants decrease as CO_2 reduction increases in order to control the required level of CO_2 reduction. It appears from the diagram that IGCC with and without carbon capture technologies are not economical and therefore they are not selected as explained in Figure 5.8.

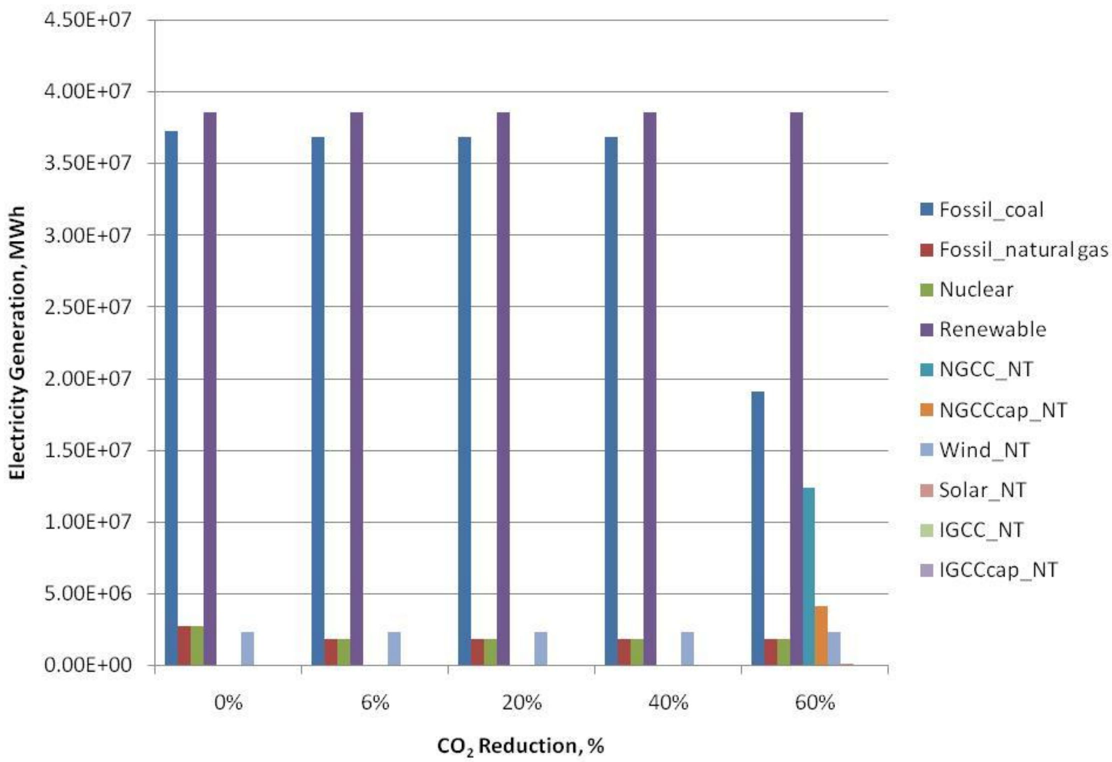


Figure 5.9 Electricity Generation Distributions vs. CO_2 Reduction at 10% Demand Growth with *New Technologies*

Load Distribution at Various CO_2 Reductions: For 10% growth in base load demand, the trends are the same as base load demand. The *new technologies* wind and NGCC without capture are selected in every CO_2 reduction scenarios. Wind remains the same in all CO_2 reduction scenarios. Renewable plants and nuclear load remain same in all scenarios. The load on existing fossil plants decreases as CO_2 reduction increases to control CO_2 reduction levels.. Some of the existing fossil technologies are not as efficient as compared to new technologies as shown in Figure 5.9. The reduction of loads in fossil plants was picked up by new technologies IGCC, NGCC with and without capture, Solar, and wind..IGCC without carbon capture was selected only at 60% CO_2 reduction. NGCC with capture was selected at 40% and 60% CO_2 reduction.

Figure 5.10 shows the electricity cost comparison with and without *new technologies*.

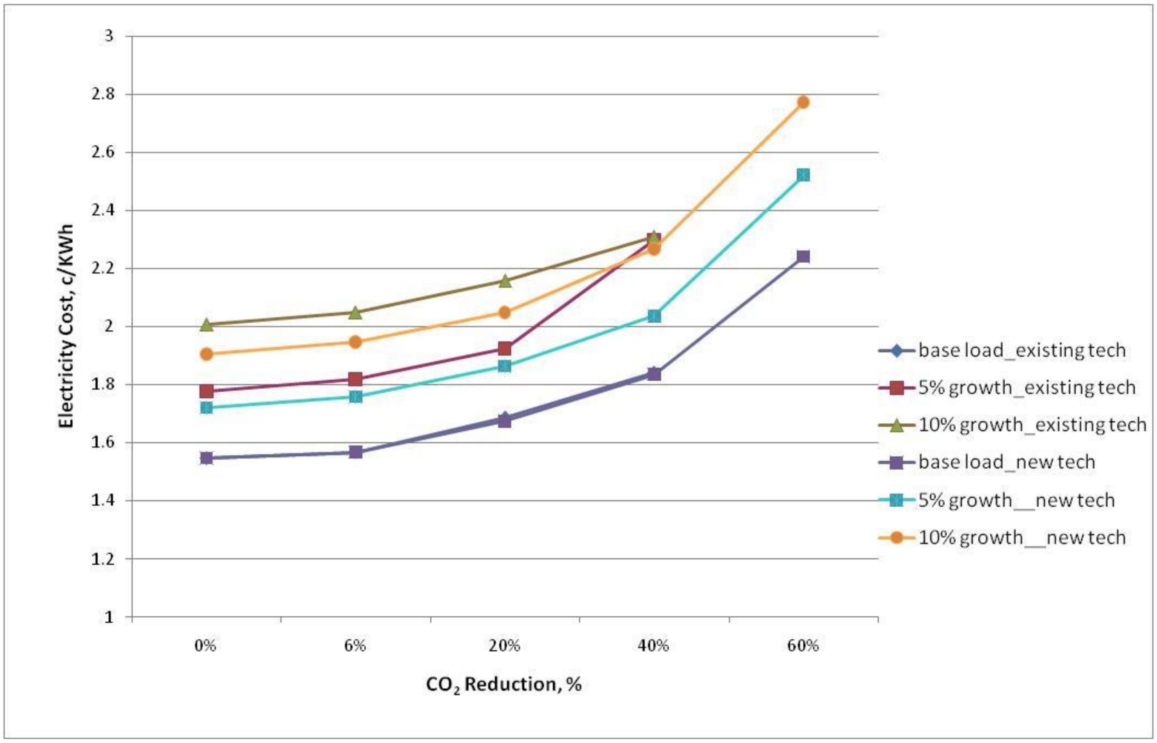


Figure 5.10 Electricity Cost vs. CO_2 Reduction Comparison with & without *New Technologies* for Various Increases in Aggregate Demand Growths

Electricity Cost Comparison with & without *New Technologies*: Electricity costs with *new technologies* are lower than with existing technologies. The *new technologies* are more efficient and use less fuel than existing technologies. However, the *new technologies* require initial commitment of capital investment. However, the operating costs of *new technologies* are a lot lower than the existing technologies as explained in Section 5.2.5. The *new technology* plants are attractive in the long term. The cost share program from government even further helps to integrate *new technologies* into the existing plants. The trends are the same at various growths in base load demands.

The effect of fuel price 10, 50 and 100% increase on electricity cost at various aggregated demand growths which are derived from Tables 5.33, 5.35 and 5.37 is shown in Figure 5.11.

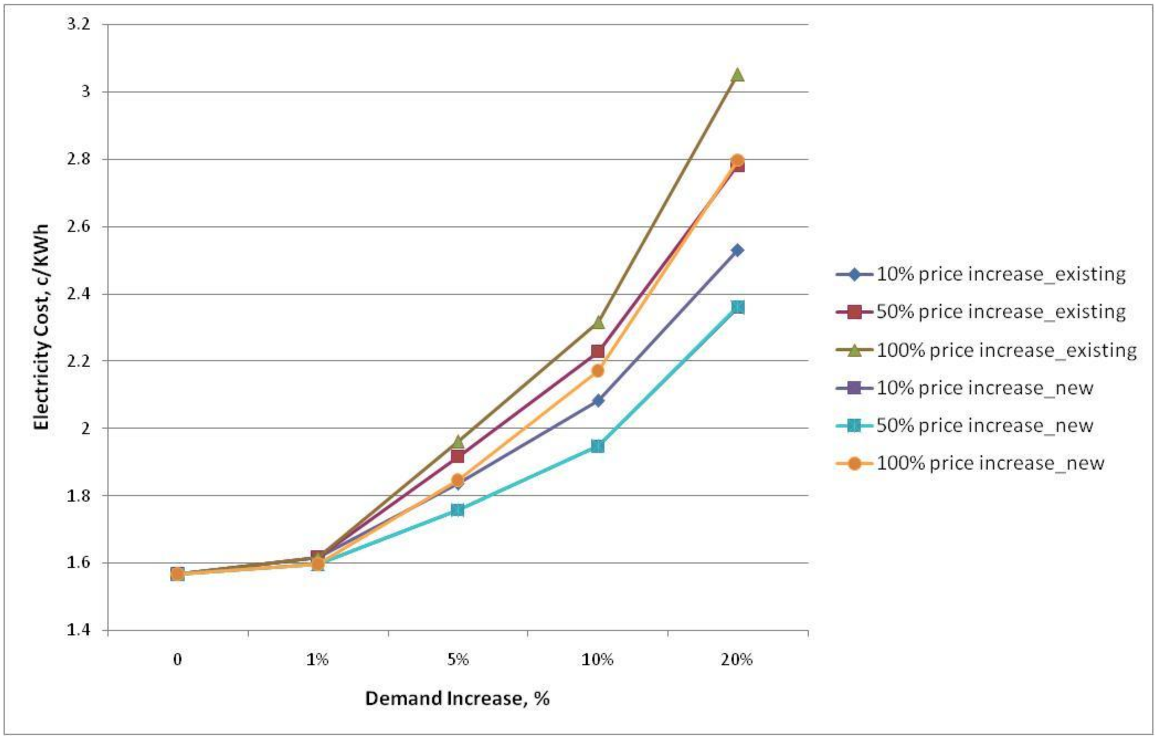


Figure 5.11 Electricity Cost Comparison for Various Increases in Aggregate Demand Growths at Various Fuel Prices Increases with and without *New Technologies*

Effect of Fuel Price Increase: Electricity costs with *new technologies* are obviously cheaper than with existing technologies. For high demand, *new technologies* are much cheaper than for low demand. Electricity cost with and without *new technologies* at various fuel prices increase is illustrated in Figure 5.11.

5.2.6 Decision Analysis

By using existing technologies, 40% CO_2 reduction can be achieved with existing power plants at base load demand and 1%, 5% and growth in base load demand. 30% CO_2 reduction can be accomplished at 10% growth and 6% CO_2 reduction at 20% growth.

6%, 20%, 40% and 60% or higher CO_2 reduction can be achieved with *new technology* power plants at 1%, 5%, 10% and 20% growth in base load demand. The total cost and cost of electricity when using existing technologies are significantly higher than when using *new technologies*.

The *new technology* power stations wind, solar, IGCC without CO_2 capture, NGCC with and without CO_2 capture are more efficient in fuel usage and fuel conversion. The operating cost and CO_2 emissions are a lot lower than with existing technologies.

Wind and solar technologies are economical at hiher CO_2 reduction scenarios.. IGCC with and without capture and NGCC with and without capture are feasible and economical. The decision is to integrate the existing technologies with *new technologies* such as wind, solar, IGCC and NGCC with and without CO_2 capture to lower CO_2 levels as well as the cost of electricity.

5.2.6.1 Comparison with Hashim (2005) Results

The results of the case study are compared with the results described by Hashim (2005). The case study focuses on planning the capacity supply to meet the projected electricity demand for the fleet of electric generating stations owned and operated by OPG (Ontario Power Generation) with a goal to minimize total annualized costs while satisfying various CO_2 emission constraints. The results show that achieving the CO_2 emission mitigation goal while minimizing costs affects the configuration of the OPG fleet in term of generation mix, capacity mix, selection of *new technologies* and optimal configuration with and without *new technologies*.

The cost of electricity for the optimal current generating electricity is the as same as Hashim's 1.54 ¢/KWh. The cost of electricity at 6% CO2 reduction is the same as Hashim's 1.57 ¢/KWh.

By using *new technologies* wind, solar, IGCC with and without capture and NGCC with and without capture, the electricity cost is 2.24 ¢/KWh at base case load demand with 60% CO_2 reduction versus Hashim's 2.44 ¢/KWh by using CO_2 capture technology. At 10% growth with 60% CO_2 reduction is 2.77 ¢/KWh versus Hashims's 3.37 ¢/KWh by using carbon capture.

6.0 Case Study – Stochastic Model

Financial Risk Management With and Without *New Technologies*
(Steps 3 & 4)

6.1 Step 3 – Financial Risk Management without *New Technologies*
6.1.1 Risk Identification

This step addresses the issue of uncertainty and financial risk. The problem is that of determining the optimal capital investment and capacity expansion plans to meet electricity demands and CO_2 reduction requirements in the face of uncertainty in one or more parameters. For example, one might consider uncertainty in:

- the cost of a particular technology
- the efficiency of a *new technology*
- the demand for electricity
- the CO_2 reduction targets.

In this case, to demonstrate the incorporation of uncertainty and financial risk into the methodology outlined in Chapter 3, uncertainty in both the demand for our product, electricity, and the cost of our main raw materials, coal and natural gas will be considered.

A so-called two-stage stochastic linear programming with recourse method was used to incorporate uncertainty into the model. In the first stage, capital investment decisions are made before the realization of uncertain parameters, while in the second stage, uncertainties in parameters are penalized. We assumed that the random events, which represent uncertainty, are described by many, mutually exclusive scenarios that are independent of the first stage decisions.

6.1.2 Modification of Model

In this step, a mathematical deterministic model is modified and formulation is presented in detail. A two-stage stochastic programming approach is applied to our case. The planning problem is characterized by two essential features: the uncertainty in the case parameter and the sequence of decisions. Capital investment of various kinds of power plants are decided at the planning stage before the uncertainty is revealed, whereas operating cost and penalty cost are made only after the uncertain parameters become known. The first class of decisions is called first stage decisions. The decisions made after the uncertainty is unveiled are called second stage or recourse decisions.

Financial risk, *Risk(x, α)*, associated with the energy planning case study, is defined as “the probability of not meeting a certain target cost minimization level referred as α as following equation”:

$$Risk(x,\alpha) = P[Cost(x) > \alpha] \tag{6.1}$$

CVaR measures risk as the expected cost when the probability that the cost exceeds α is $1 - \beta$ and is defined by Equation 6.2.

$$CVaR = \alpha + \frac{1}{1-\beta} \cdot \sum_s p_s \cdot \eta_s \tag{6.2}$$

With respect to a specified probability level β, α is the lowest amount such that with probability β, the cost will not exceed α, and CVaR is the conditional expectation of cost above the amount α. Usually, β is pre-selected as 0.95 or 0.99; here we choose it as 0.95. Risk is presented because the two stage stochastic models do not take into account the variability of the second stage cost except for its expected value. Therefore, the concept of downside risk to measure the recourse cost variability and obtain solutions is appealing to a risk adverse investor.

In order to minimize cost of electricity generation and minimize financial risk at the same time, a mathematic formulation, which is called mean-risk model, is introduced. Bagajewicz (2004) has shown that a solution that minimizes financial risk at cost minimization target also minimizes the expected value of cost of power generation.

$$\min(Cost + \lambda \cdot Risk) \tag{6.3}$$

where *Cost* denotes the expected value of cost and *CVaR* means a risk measure. λ is a suitable weighting factor. The mean-risk model aims at minimizing the weighted sum of two competing objectives. Viewed from a more general perspective, it is a scalarization of the multi-objective optimization problem. As the weighting factor increases, the financial risk management becomes more important, while cost minimization turns less important. However Schultz (2006) proves that that does not the mean the risk model objective function value changes as the weighting factor does.

Power plants are divided into the following types: fossil fuel plants, renewable plants, including nuclear, hydroelectric and wind, and new fossil fuel plants with and without CO_2 capture, which are notated as *f*, *rn*, *p* and *pc*, respectively, in the model formulation.

Two possible options named fuel balancing and fuel switching are used here for reducing CO_2 emissions by a certain target. Fuel balancing is the optimal adjustment of the electricity generation of different power plants, and fuel switching involves switching fossil fuel plants from using carbon-intensive fuel (i.e. coal) to less carbon intensive fuel (i.e. natural gas).

6.1.2.1 Objective Function

The object cost function consists of fixed cost *FixC*, expected cost *ExpC* and financial risk cost $\lambda \cdot CVaR$. The *FixC* consists of the following: capital investment cost for all power plants (Equation 5.2) and retrofit cost for fossil fuel plants (Equation 5.3). The capital cost and retrofit costs are the same as in the deterministic model as explained in Section 5.1.3.1. Furthermore, electricity generation penalty cost (Equation 6.5) and financial risk cost (Equation 6.7) need to be added to obtain an integrated objective function.

$$Min\ Tot = FixC(Capital\ Cost + Retrofit\ Cost) + ExpC + \lambda \cdot CvaR \tag{6.4}$$

$$ExpC = \sum_s p_s \cdot OpC_s + \sum_s p_s \cdot (c^+ \cdot z_s^+ + c^- \cdot z_s^-) \tag{6.5}$$

$$OpC_s = \sum_{f,j} (O_f + \Pr_{j,s} \cdot HR_f) \cdot E_f + \sum_{rn} O_{rn} \cdot E_{rn} + \sum_{p,j} (O_p + \Pr_{j,s} \cdot HR_p) \cdot E_p \tag{6.6}$$

$$CVaR = \alpha + \frac{1}{1-\beta} \cdot \sum_s p_s \cdot \eta_s \tag{6.7}$$

where the first two terms are *FixC* first stage decision cost and *ExpC* is the second stage cost corresponding to Scenario *s*, which has occurrence probability p_s, $s = 1,\ldots,NS$. In addition, one type of downside risk measure, which is called conditional value at risk *CVaR* in financial risk management, is introduced to minimize risk. The term *CVaR* is the financial risk to be minimized.

The first stage decision variables are binary variables. Binary variables are used to determine capital investment cost. The second stage decision variables consists of capital expenaion cost and penalty cost which are positive variables.

The positive variables are the electricity generation amount for fossil fuel plants, renewable plants and new fossil fuel plants; z_s^+ and z_s^- are recourse variables for the electricity generation amount overproduced/under-produced compared to stochastic demand; the financial risk management variable is α. λ is an adjustable weight to control the relative importance between expectation and risk. β is a constant, which is generally chosen to be 0.95 as described by Johnson (2004). The mean risk model aims at minimizing the weighted sum of two competing objectives. It is a scalarization of the multi objective optimization problem. That is why the weighting factor is needed to show which objective is more important.

6.1.2.2 Model Constraints

The minimization of the objective functions represented above is subjected to the following constraints. The model constraints are divided into three parts for deterministic, stochastic and financial risk.

Financial Risk Constraint

$$\eta_s \geq FixC + OpC_s + c^+ \cdot z_s^+ + c^- \cdot z_s^- - \alpha \tag{6.8}$$

For stochastic parts, model constraints deal with uncertain parameters, such as raw material cost and demand corresponding to different scenarios. The aim of the inequality is to choose the first stage decision in an optimal way without anticipation of future outcomes of uncertainties. The costs of two stage sequential process of decision and observations are expressed by this inequality. C^+ is a fixed penalty cost per demand of under-production (shortfall) of electricity. C^- is a fixed penalty cost per demand of overproduction (surplus) of electrity. The values ($/MWh) of both overproduction and underproduction are based on the experience and historical data.

Energy Balance/Demand Satisfaction

The total electricity generation must be equal to or greater than the desired electricity demand, where *Demand* and $Pr_{j,\, s}$ are stochastic parameters for electricity demand and raw material cost for coal and natural gas corresponding to Scenario s. The total electricity generation constraint *TotE* is the same as the deterministic constraint (Equation 5.5).

$$Demand_s = TotE - z_s^+ + z_s^- \tag{6.9}$$

$$z_s^+ \geq TotE - Demand_s \tag{6.10}$$

$$z_s^+ \geq 0 \tag{6.11}$$

$$z_s^- \geq Demand_s - TotE \tag{6.12}$$

$$z_s^- \geq 0 \tag{6.13}$$

The other stochastic model constraints such as capacity, carbon emission, fuel selection and plant shutdown constraints are the same as those of the deterministic model

(Equations 5.7 – 5.14). Zs^+ and Zs^- are recourse variables for electricity generation amount over produced and under produced compared to stochastic demand.

6.1.3 Risk Assessment & Analysis

In our case study, we show the effectiveness of the methodology above. When the weighting factor increases, *Cost* increases while *Risk* decreases. *Cost* is the total cost of electricity generation, including capital investment, operational cost and penalty cost for power under-production/over-production as compared to the demand load. Risk is the expected value that is obtained when total cost of electricity generation exceeds a certain target α, and its probability is $1 - \beta$. CVaR is applied to measure the financial risk.

Through our results we also show that the objective function value does not change for all changing weighting factors. It changes only for certain effective points, which is the same as Schultz's conclusion and results.

In the cost analysis, *TotCost* is equal to the summation of *FixC* and *ExpC*. When λ equals 0, financial risk is ignored and only cost is minimized. On the other hand, when λ equals ∞, only financial risk is minimized and total cost is neglected. Therefore, when λ increases, the value of total cost increases as value of financial risk decreases.

From our analysis, we found that, regardless of the value of λ, the optimal mix of power plants remains constant. In this study, carbon reduction as 6% is considered.

The impact of the following is covered in the scope:

- Various penalty values of over- and under-production
- Sensitivity Analysis – Fuel price increase
- Validation of model
- Increase in CO_2 Reduction

6.1.3.1 Impact of Various Penalty Values of Over- & Under-Production

Various scenarios are considered to see the impact of various penalties of over- and under-production on the total cost of electricity and financial risk cost and also the impact of the weighting factor on both costs. Based on discussion with energy experets (Appendix A) and keep the industry at safe position, the following three scenarios are considered:

- $C^+ = 40$; $C^- = 40$

- $C^+ = 20$; $C^- = 200$
- $C^+ = 40$; $C^- = 400$

Scenario 1: $C^+ = 40$; $C^- = 40$

In this scenario, C^+, the penalty for a shortage of demand or excessive generated power, is assumed to be \$40/MWh. C^-, the penalty for excessive demand or shortage of power, is also assumed to be \$40/MWh. The results are shown in Tables 6.1 and 6.2.

Table 6.1 Total Cost of Electricity& Financial Risk Cost vs. Weighting Factor λ with Penalty $C^+ = 40$; $C^- = 40$ without *New Technologies*

λ	***TotCost* (\$/year)**	***FixCost* (\$/year)**	***ExpC* (\$/year)**	***CVaR* (\$/year)**
0	2.0751E+9	1.5928E+9	4.8231E+8	2.5575E+9
0.1	2.0751E+9	1.5928E+9	4.8231E+8	2.5575E+9
0.5	2.1581E+9	1.8142E+9	3.4383E+8	2.3636E+9
0.6	2.1581E+9	1.8142E+9	3.4383E+8	2.3636E+9
1	2.1581E+9	1.8142E+9	3.4383E+8	2.3636E+9
∞	2.1581E+9	1.8142E+9	3.4383E+8	2.3636E+9

In this scenario, the penalty for excess power and shortage of power is the same. The total cost and financial risk are based on the penalty value we consider for the study.

The total cost, which is the summation of fixed cost and expected cost, increases when λ increases and financial risk decreases as shown in Table 6.1. Therefore, when the weighting factor λ increases, the value of total cost increases as the value of financial risk decreases. After a certain level of $\lambda = 0.5$, there is no impact on total cost and financial risk. To increase λ means that we consider financial risk management is more important than total cost minimization. When λ is 0, the multi objective model reduces to traditional two stage stochastic model without risk management. When λ is infinity, the mean risk model only considers risk management as ignoring total cost minimization.

As the weighting factor increases, the financial risk management becomes more and more important, while cost minimization turns less important. However, it does not mean risk model objective function value changes as the weighting factor does as proved by Schultz (2006).

Table 6.2 Electricity Generation Distribution vs. Weighting Factor λ for Various Types of Power Stations with Penalty C^+ = 40; C^- = 40 without *New Technologies*

λ	Fossil Fuel (MWh)	Nuclear (MWh)	Renewable (MWh)	Coal-new (MWh)	NGCC-new (MWh)
0	3.6162E+7	3.1517E+7	3.8969E+7	0	0
0.1	3.6162E+7	3.1517E+7	3.8969E+7	0	0
0.5	3.6162E+7	4.1900E+7	3.8969E+7	0	0
0.6	3.6162E+7	4.1900E+7	3.8969E+7	0	0
1	3.6162E+7	4.1900E+7	3.8969E+7	0	0
∞	3.6162E+7	4.1900E+7	3.8969E+7	0	0

The total cost, which is the summation of fixed cost *FixC* and expected cost *ExpC* and the financial risk cost are based on the assumed penalty values. The total cost of electricity at the weighting factor of 0.5 is \$ 2.1581E+9/year at 6% CO_2 reduction without *new technology* as shown in Table 6.2. This cost is 14% higher the cost of \$ 1.8893E+9, which is the total cost without risk consideration.

The electricity generation is 1.1703E+8 MWh with financial risk consideration at 6% CO_2 reduction without *new technology*. This is 3% less than the electricity generation power of 1.2058E+8 MWh, which is the electricity generation without financial risk consideration. By consideration financial risk, we pay 14% more and produce 3% less than base load demand.

Scenario 2: C^+ = 20, C^- = 200

In this scenario, C^+, the shortage of demand or excessive generated power, is assumed to be \$20/MWh. C^-, the excessive demand or shortage of power, is assumed to be \$200/MWh. The results are shown in Tables 6.3 and 6.4.

Table 6.3 Total Cost of Electricity& Financial Risk Cost vs. Weighting Factor λ with Penalty C^+ = 20, C^- = 200 without *New Technologies*

λ	***TotCost*** **(\$/year)**	***FixCost*** **(\$/year)**	***ExpC*** **(\$/year)**	***CVaR*** **(\$/year)**
0	2.6656E+9	2.4244E+9	2.4121E+8	2.9068E+9
0.1	2.6774E+9	2.3337E+9	3.4365E+8	2.7777E+9
0.5	2.6795E+9	2.3214E+9	3.5813E+8	2.7599E+9
0.6	2.6795E+9	2.3214E+9	3.5813E+8	2.7599E+9
1	2.6795E+9	2.3214E+9	3.5813E+8	2.7599E+9
∞	2.6795E+9	2.3214E+9	3.5813E+8	2.7599E+9

Table 6.4 Electricity Generation Distribution vs. Weighting Factor λ for Various Types of Power Stations with Penalty $C^+ = 20$, $C^- = 200$ without *New Technologies*

λ	Fossil Fuel (MWh)	Nuclear (MWh)	Renewable (MWh)	Coal –new (MWh)	NGCC-new (MWh)
0	4.9896E+7	4.1900E+7	3.8969E+7	0	0
0.1	4.7975E+7	4.1900E+7	3.8969E+7	0	0
0.5	4.7704E+7	4.1900E+7	3.8969E+7	0	0
0.6	4.7704E+7	4.1900E+7	3.8969E+7	0	0
1	4.7704E+7	4.1900E+7	3.8969E+7	0	0
∞	4.7704E+7	4.1900E+7	3.8969E+7	0	0

The total cost, which is the summation of fixed cost and expected cost, increases when λ increases and financial risk decreases as shown in Table 6.3. Therefore, when λ increases, the value of total cost increases as the value of financial risk decreases. After a certain level of λ, there is an impact on total cost and financial risk. The certain level is highly dependent on the penalty. If penalty parameters are different, then the level changes accordingly. The total cost is more because the penalty for excess power and shortage in power are also more than in Scenario 1. Total cost and financial risk are based on the penalty value we consider for the study.

The total cost, which is the summation of *FixC* and *ExpC* and the financial risk cost are based on the assumed penalty values. The total cost of electricity at the weighting factor of 0.5 is \$ 2.6795E+9/year at 6% CO_2 reduction without *new technology*. This cost is 42% higher the cost of \$ 1.8893E+9, which is the total cost without risk consideration.

The electricity generation is 1.2857E+8 MWh with financial risk consideration at 6% CO_2 reduction without *new technology*. This is 6.6% more than the electricity generation power of 1.2058E+8 MWh, which is the electricity generation without financial risk consideration. By consideration financial risk, we pay 42% more and produce 6.6% more than base load demand. The results are shown in Table 6.4.

Scenario 3: $C^+ = 40$, $C^- = 400$

In this scenario, C^+, the cost of over-production or a short fall in demand, was assumed to be \$40/MWh. However, C^-, the more serious case of excessive demand resulting in a shortage of power, was assumed to be \$400/MWh. The results are shown in Tables 6.5 and 6.6.

Table 6.5 Total Cost of Electricity & Financial Risk Cost vs. Weighting Factor λ with Penalty $C^+ = 40$, $C^- = 400$ without *New Technologies*

λ	*TotCost* ($/year)	*FixC* ($/year)	*ExpC* ($/year)	*CVaR* ($/year)
0	2.9068E+9	2.4244E+9	4.8241E+8	3.3891E+9
0.1	2.9068E+9	2.4244E+9	4.8241E+8	3.3891E+9
0.5	2.9068E+9	2.4244E+9	4.8241E+8	3.3891E+9
0.6	2.9068E+9	2.4244E+9	4.8241E+8	3.3891E+9
1	3.0376E+9	2.3214E+9	7.1625E+8	3.1984E+9
∞	3.0376E+9	2.3214E+9	7.1625E+8	3.1984E+9

Table 6.6 Electricity Generation Distribution vs. Weighting Factor λ for Various Types of Power Stations with Penalty $C^+ = 40$, $C^- = 400$ without *New Technologies*

λ	Fossil Fuel (MWh)	Nuclear (MWh)	Renewable (MWh)	Coal-new (MWh)	NGCC-new (MWh)
0	4.9896E+7	4.1900E+7	3.8969E+7	0	0
0.1	4.9896E+7	4.1900E+7	3.8969E+7	0	0
0.5	4.9896E+7	4.1900E+7	3.8969E+7	0	0
0.6	4.9896E+7	4.1900E+7	3.8969E+7	0	0
1	4.7704E+7	4.1900E+7	3.8969E+7	0	0
∞	4.7704E+7	4.1900E+7	3.8969E+7	0	0

The total cost, which is the summation of fixed cost and expected cost, increases when λ increases and financial risk decreases as shown in Table 6.5. Therefore, when λ increases, the value of the total cost per year increases and the value of financial risk cost per year decreases. After a certain level of λ, there is no impact on total cost and financial risk.

The total cost, which is the summation of *FixC* and *ExpC* and the financial risk cost are based on the assumed penalty values. The total cost of electricity at the weighting factor of 1.0 is $ 3.0376E+9/year at 6% CO_2 reduction without *new technology*. This cost is 53.6% higher the cost of $ 1.9776E+9, which is the total cost without risk consideration.

The electricity generation is 1.2873E+8 MWh with financial risk consideration at 6% CO_2 reduction without *new technology*. This is 6.6% more than the electricity generation power of 1.2058E+8 MWh, which is the electricity generation without financial risk consideration. By consideration financial risk, we pay 53.6% more and produce 6.8% more than base load demand. The results are shown in Table 6.6.

When the penalty cost for over-producing or under-producing increases, the total cost per year and financial risk cost per year also increase. If we double the penalty cost from

$C^+ = 20$; $C^- = 200$ to $C^+ = 40$; $C^- = 400$, the total cost increases by 13% and the financial risk cost increases by 16%. The electricity power generation is almost the same. However, the electricity generation with financial risk increases by 6.6% from the electricity generation without financial risk consideration. If penalty for under-producing power is low ($C^- = 40$) then 3% less power is produced. The effect of weighting factor on total cost per year and financial cost per year is not the same and it varies in all scenarios.

Electricity generation from fossil power stations decreases as total cost increases and financial risk decreases. The details of electricity generation of various types of power stations are included in Table B.18 (Appendix B).

6.1.3.2 Sensitivity Analysis – Fuel Price Increase

To verify the correctness of the stochastic model, the base price of fuel (e.g. coal and natural gas) is changed. Only one case $C^+ = 40$; $C^- = 400$ is selected to see the impact of fuel price increase.

First we increase the base price to 10%. Thus, the base price for coal and natural gas is \$2.2/GJ and \$6.1/GJ, respectively. The corresponding lower prices and higher prices for coal and natural gas are \$1.815/GJ and \$3.025/GJ and \$5.0325/GJ and \$8.3875/GJ The corresponding results are shown in Table B.19, Table B.20 and Table B.21 (Appendix B) at a fuel price increase of 10%, Table B.22, Table B.23 and Table B.24 (Appendix B) at a fuel price increase of 50% and Table B.25, Table B.26 and Table B.27 (Appendix B) at a fuel price increase of 100%.

The trend of total cost per year and financial risk cost per year is the same as described in Scenarios 1, 2 and 3. The total cost per year increases when the weighting factor λ increases and financial risk cost per year decreases. After a certain level of weighting factor λ there is no impact on the total cost and financial risk cost.

The total cost per year and financial risk cost per year increase with an increase in fuel price. The total cost per year increases by 45% when the fuel price is increased by 10% because of new NGCC power plants. The electricity power generation MWh is marginally decreased. The total cost per year and financial risk cost per year increase by 32% when the fuel price is increased by 100% because of new NGCC plants and fuel balancing. However, the electricity power generation MWh is marginally increased when we increase fuel price by 50% and 100%.

There is small reduction and fuel balancing in fossil power generation in all three 10%, 50% and 100% fuel price increase as shown in Table B.21, Table B.24 and Table B.27 (Appendix B).

6.1.3.3 Validation of Stochastic Model

The stochastic model is validated by changing the conditions of the model to bring the results of the stochastic model to the results of the deterministic model.

In order to validate the stochastic model, the following conditions of demand and probability are assumed:

- $D_{low} = D_{med} = D_{high}$
- $P_{low} = P_{high} = 0$
- $P_{med} = 1$

The demands for different scenarios are kept the same and the probability for medium raw materials is 1 while for others is 0. The total cost and financial risk minimization cost are shown in Table 6.7 and the load distribution is shown in Table 6.8.

Table 6.7 Total Cost of Electricity& Financial Risk Cost vs. Weighting Factor λ and Demand $D_{low} = D_{mid} = D_{high} = D$ and Fuel Price Probability $Pr_{low} = Pr_{high} = 0$, $Pr_{mid} = 1$

λ	*TotCost* ($/year)	*FixCost* ($/year)	*ExpC* ($/year)	*CVaR* ($/year)
0	1.8893E+9	1.8893E+9	0	1.8893E+9
0.1	1.8893E+9	1.8893E+9	0	1.8893E+9
0.5	1.8893E+9	1.8893E+9	0	1.8893E+9
0.6	1.8893E+9	1.8893E+9	0	1.8893E+9
1	1.8893E+9	1.8893E+9	0	1.8893E+9
∞	1.8893E+9	1.8893E+9	0	1.8893E+9

If demands for different scenarios are the same and the probability for medium raw materials is 1 while for others is 0, then total cost and financial risk minimization cost are almost the same as the deterministic model's total cost (0.005% difference), which shows that the stochastic model is the same as the deterministic model in the sense that we can treat stochastic model as deterministic model in Tables 6.7.

The load distribution of power plants is the same as deterministic model in the sense that uncertainties are known the same as deterministic model so that we can regard stochastic model as deterministic model. The demand level is set at demand $D_{low} = D_{mid} = D_{high} = D$ and fuel price probability $Pr_{low} = Pr_{high} = 0$, $Pr_{mid} = 1$ as shown in Table 6.8.

Table 6.8 Electricity Generation Distribution vs. Weighting Factor λ for Various Types of Power Stations and Demand $D_{low} = D_{mid} = D_{high} = D$ and Fuel Price Probability $Pr_{low} = Pr_{high} = 0, Pr_{mid} = 1$

λ	Fossil Fuel (MWh)	Nuclear (MWh)	Renewable (MWh)	Coal-new (MWh)	NGCC-new (MWh)
0	3.7833E+7	4.1900E+7	3.8969E+7	0	0
0.1	3.7833E+7	4.1900E+7	3.8969E+7	0	0
0.5	3.7833E+7	4.1900E+7	3.8969E+7	0	0
0.6	3.7833E+7	4.1900E+7	3.8969E+7	0	0
1	3.7833E+7	4.1900E+7	3.8969E+7	0	0
∞	3.7833E+7	4.1900E+7	3.8969E+7	0	0

The load distribution of power plants is the same as deterministic model in the sense that the uncertainties are known the same as deterministic model such that we can validate stochastic model. If the results of the stochastic model are the same as the deterministic model, then the stochastic model is validated. The demand level is set at demand $D_{low} = D_{mid} = D_{high} = D$ and fuel price probability $\mathrm{Pr}_{low} = \mathrm{Pr}_{high} = 0$, $\mathrm{Pr}_{mid} = 1$ as shown in Table 6.8.

The data from Table 6.7 and Table 6.8 confirm that by changing the conditions of the stochastic model, the results of the stochastic model are the same as deterministic model. The electricity generation and costs are constant for all weighting factors and match with numbers without uncertainty.

6.1.3.4 Increase in CO_2 Reduction

Results were compared between a 6% CO_2 reduction and a 20% CO_2 reduction without *new technologies*. In the scenario, C^+, the cost of over-production or a shortfall in demand was assumed to be \$40/MWh, However, C^-, the more serious case of excessive demand resulting in a shortage of power, was assumed to be \$400/MWh. The results are shown in Table B.28 and Table B.29 (Appendix B).

The results show that there is a 4.4% increase in the best total cost under uncertainty and a 4% increase in the financial risk cost when there is an increase in CO_2 reduction from 6% to 20%. The total electricity generation is the same at 1.2858E+8 MWh. There is a reduction of fossil power at a weighting factor of 1.0.

6.1.4 Evaluation of Results & Decision Analysis

6.1.4.1 Total Cost & Electricity Generation under Uncertainty

Figure 6.1 explains the relationship between financial risk cost per year and total cost per year at various weighting factors ***λ*.** The data is taken from Table 6.5.

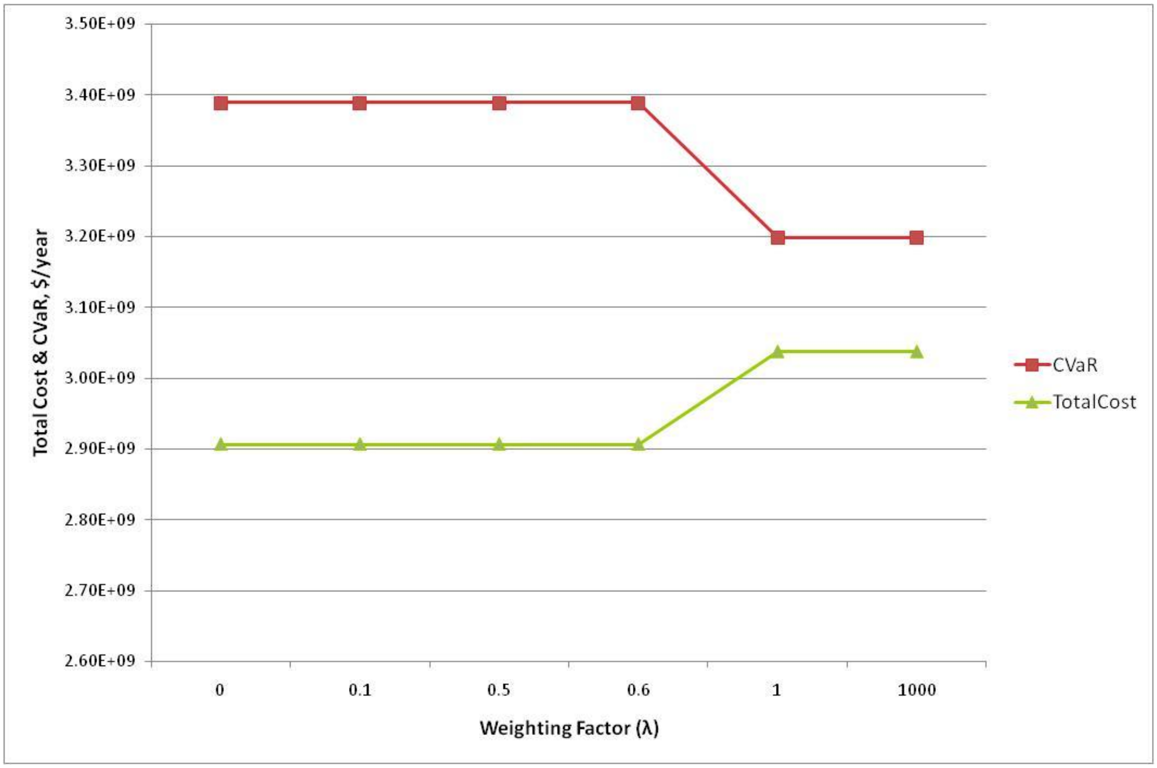


Figure 6.1 Relationships between Financial Risk & Total Cost of Electricity vs. Weighting Factor λ with Penalty C^+ = 40; C^- = 400 without *New Technologies*

When the weighting factor increases, *Cost* increases while *Risk* decreases. *Cost* is the total cost of electricity generation, including capital investment, operational cost and penalty cost for power under-production/over-production as compared to the demand load. The financial risk is minimized as the weighting factor increases.

Risk is the expected value of total cost of electricity generation when the total cost exceeds a certain target α, and its probability is $1 - \beta$. CVaR is applied to measure the financial risk.

Through our results we also show that the objective function value does not change for all changing weighting factors. It changes only for certain effective points as shown in Figure 6.1, which is also the same as Schultz's conclusion and results.

In the cost analysis, *TotCost* is equal to the summation of *FixC* and *ExpC*. When λ equals 0, financial risk is ignored and only cost is minimized. On the other hand, when λ equals ∞, only financial risk is minimized and total cost is neglected. Therefore, when λ increases, the value of total cost increases as value of financial risk decreases.

Figure 6.2 shows the relationship of electricity generation distribution of various types of power station with risk penalty C^+ = 40; C^- = 400 at various weighting factors, λ.

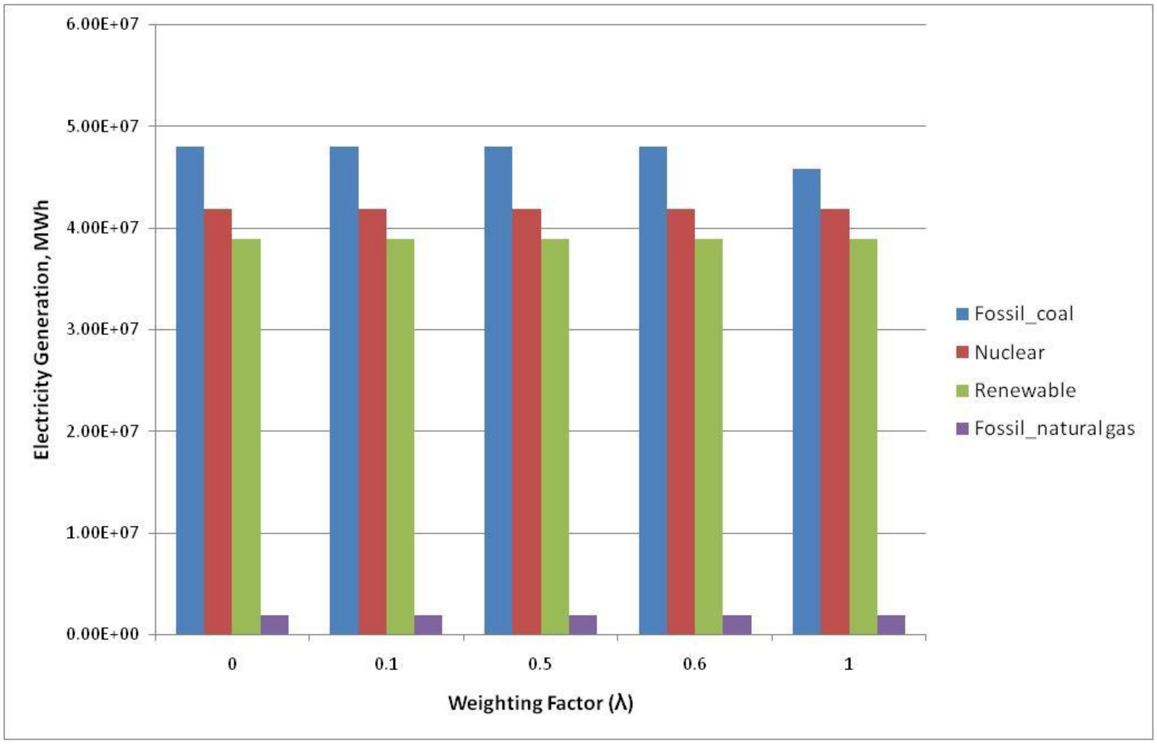


Figure 6.2 Electricity Generation Distribution vs. Weighting Factor λ for Various Types of Power Stations with Penalty $C^+ = 40$; $C^- = 400$ without *New Technologies*

When the weighting factor increases, power generation of fossil fuel plants decreases by a small amount and that of renewable energy and nuclear power stations stays constant. Since the penalty for under-producing $C^- = 400$ is high, the optimizer selects the natural gas and renewable power constant and drops fossil coal power and increase total cost and reduce financial risk cost as shown in Figure 6.2. The data is taken from Table 6.6. The trend is the same when fuel price increases as shown in Tables B.21, B.24 and B.27 (Appendix B)

Figure 6.3 shows sensitivity analysis curves for various fuel price increases. The total cost of electricity per year and financial cost per year are compared with various weighting factors λ under various fuel price increases. The results are compared with Figure 6.1 to see the impact of fuel price. The penalty $C^+ = 40$; $C^- = 400$ is considered for this case and data is taken from Tables B.19, B.20, B.22, B.23, B.25 and B.26 (Appendix B).

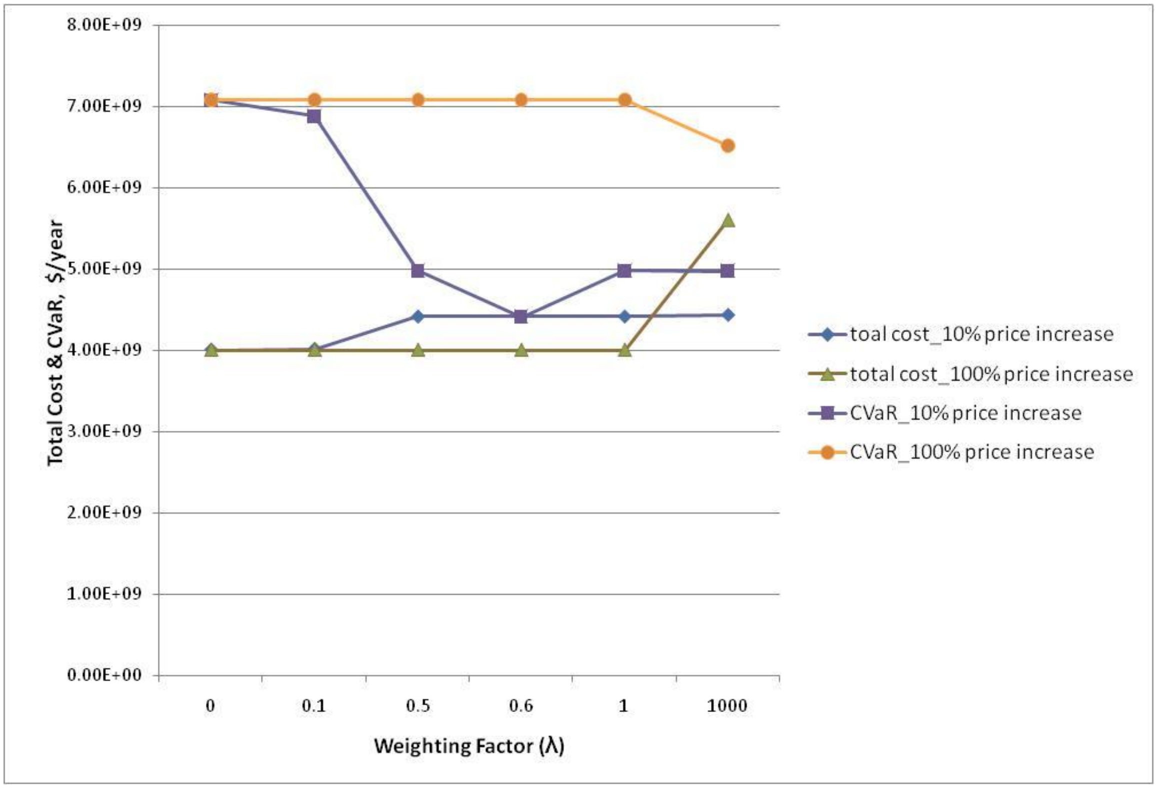


Figure 6.3 Total Cost of Electricity & Financial Risk Cost vs. Weighting Factor λ with Penalty $C^+ = 40$; $C^- = 400$ for Various Fuel Price Increases without *New Technologies*

When the raw material price increases, the total cost per year increases, and the financial risk cost per year also increases accordingly. As the weighting factor grows, total cost per year increases and financial risk cost per year decreases as shown in Figure 6.3.

The trend of total cost per year and financial risk cost per year is the same as described in Figure 6.1. The total cost per year increases when the weighting factor λ increases and financial risk cost per year decreases. After a certain level of weighting factor λ there is no impact on the total cost and financial risk cost.

The total cost per year and financial risk cost per year increase with an increase in fuel price. The total cost per year increases by 45% when the fuel price is increased by 10% due to new NGCC plants. The electricity power generation MWh is marginally decreased. The total cost per year and financial risk cost per year increase by 32% when the fuel price is increased by 100% because of fuel balancing and new NGCC plants.. However, the electricity power generation MWh is marginally increased when we increase fuel price by 50% and 100%.

There is small reduction and fuel balancing in fossil power generation in all three 10%, 50% and 100% fuel price increase as shown in Table B.21, Table B.24 and Table B.27 (Appendix B).

Figure 6.4 shows the relationship between total cost of electricity per year and financial risk cost per year at various weighting factors when the low demand, medium demand and high demand are equal, low probability and high probability are zero and medium probability is 1.

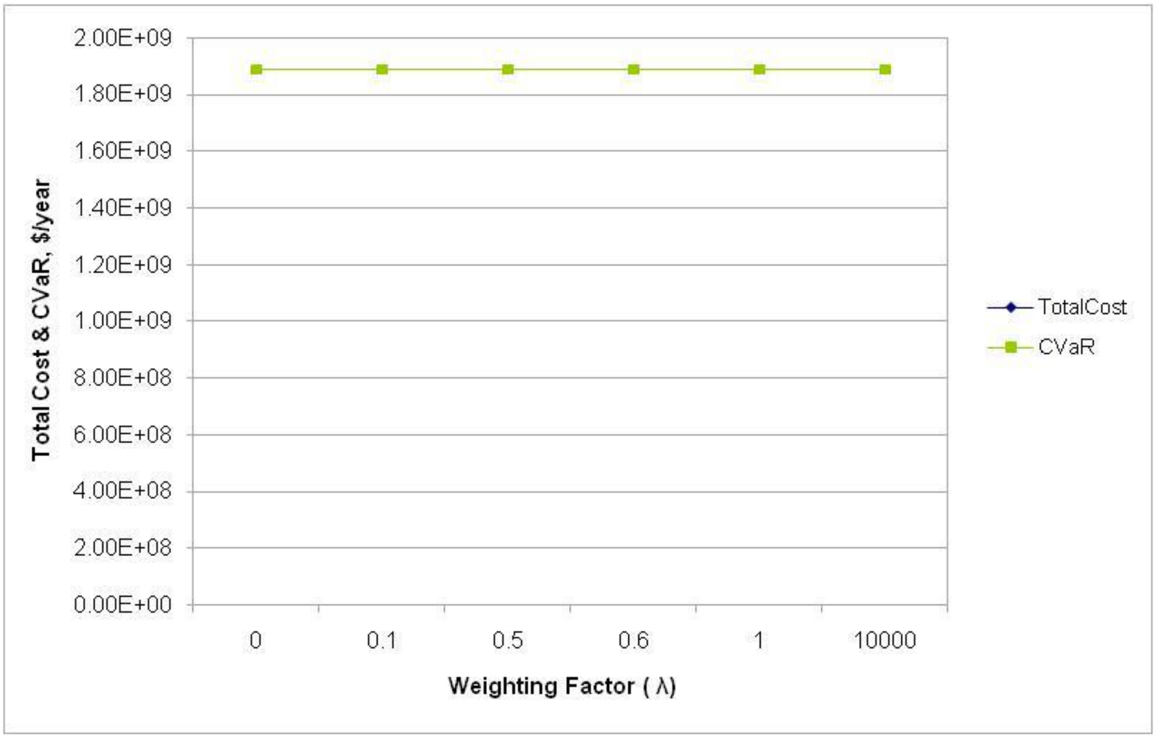


Figure 6.4 Total Cost of Electricity & Financial Risk Cost vs. Weighting Factor λ and Demand $D_{low} = D_{mid} = D_{high} = D$ and Fuel Price Probability $Pr_{low} = Pr_{high} = 0$, $Pr_{mid} = 1$

The total cost and financial risk curves are plotted against the weighting factors λ and both curves are constant as shown in Figure 6.4. In this case, the demands for different scenarios low, medium and high are kept the same and the probability for medium raw materials is 1 while for others is 0; therefore, the total cost and financial risk minimization cost are almost the same as the deterministic model. The results show when uncertainties are known then the stochastic model is the same as the deterministic model.

Figure 6.5 shows the relationship between the electricity generation distribution at various types of power stations at various weighting factors when the low demand, medium demand and high demand are equal, low probability and high probability are zero and medium probability is 1.

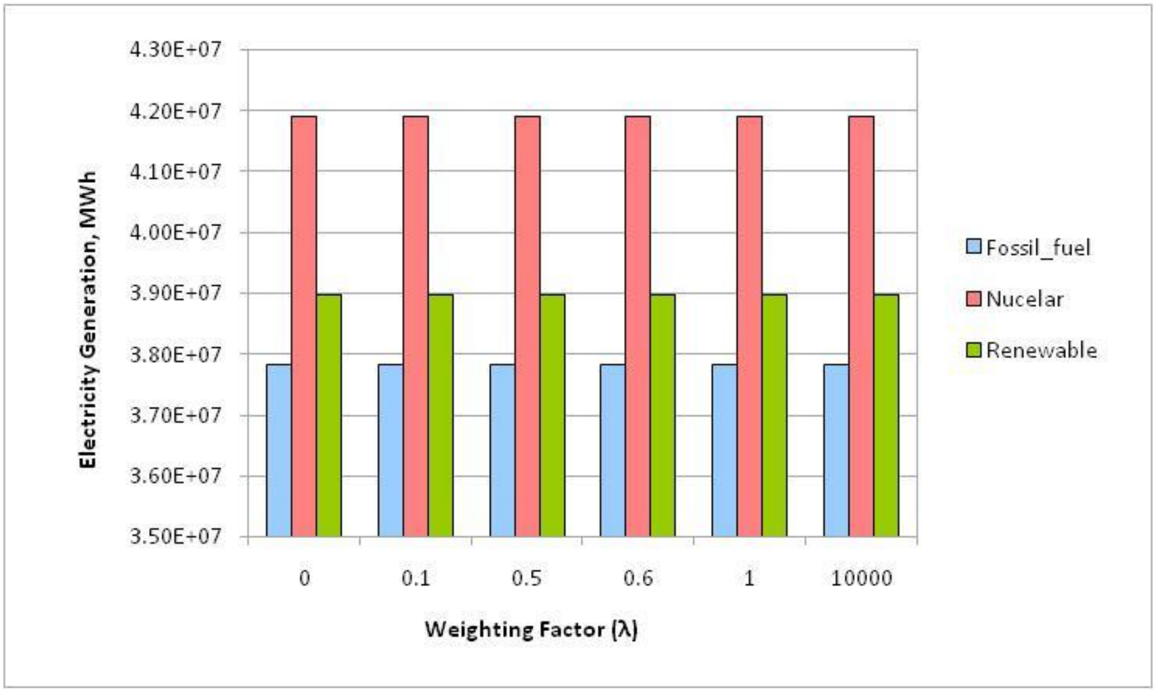


Figure 6.5 Electricity Generation Distribution vs. Weighting Factor *λ* for Various Types of Power Stations and Demand $D_{low} = D_{mid} = D_{high} = D$ and Fuel Price Probability $Pr_{low} = Pr_{high} = 0$, $Pr_{mid} = 1$

In Figure 6.5, the demand level is set at demand $D_{low} = D_{mid} = D_{high} = D$ and fuel price probability $\mathrm{Pr}_{\mathrm{low}} = \mathrm{Pr}_{\mathrm{high}} = 0$, $\mathrm{Pr}_{\mathrm{mid}} = 1$ as shown in Table 6.8. When the weighting factor increases, power generation all plants are remain constant whereas in Figure 6.2 fossil coal power decreases and that of renewable energy and nuclear power stations stays constant. It shows that when low, medium and high demands are set equal and low and high probability are set zero and medium probability is et one, there is no uncertainty and there is no impact o weighting factor.

6.2 Financial Risk Management with *New Technologies*

6.2.1 Risk Identification

This step addressed the issue of uncertainty and financial risk aspects with *new technologies*. This is the same problem as presented in Section 6.1, just another application with the addition of *new technologies*. The problem is that of determining capital investment and plants capacity expansions in order to meet uncertain electricity demands and CO_2 reduction requirements. Uncertainty is considered in both demand and cost of coal and natural gas. Therefore, a two-stage stochastic linear program with recourse method is used to formulate the stochastic model. The first stage decisions include capital investment, while the second stage decisions include plants capacity expansions after uncertainties are revealed and then certain electricity amount need to be penalized. We assume that the random events, which occur at the second stage, are described by finitely many, mutually exclusive scenarios that are independent of the first stage decisions. These second stage scenarios are denoted by index *s* and are assumed to occur with respective probabilities p_s, $s = 1, NS$. In addition, one type of downside risk measure, which is called conditional value at risk in financial risk management, is introduced to minimize risk.

The *new technologies* added to the original model, are solar, wind, IGCC, IGCC with capture, NGCC and NGCC with capture. The capital investment and operating cost of *new technology* are given and added into the objective function.

The maximum capacity of *new technologies* and existing technologies are the same as those used in the deterministic model.

6.2.2 Model Modification

6.2.2.1 Objective Function

The stochastic model is modified to include *new technologies.* The objective function is the same as for the stochastic model Equation 6.4 with *new technology*. The objective function consists of fixed cost *FixC*, expected cost *ExpC*, and financial risk cost *λ·CVaR.* The fixed cost *FixC* consists of the following: capital investment cost for all power plants (Equation 5.2), retrofit cost for fossil fuel plants (Equation 5.3), capital cost of *new technology* power plants (Equation 5.16), capture cost (Equations 5.18), and sequestration cost (Equation 5.19). Furthermore, the electricity generation penalty cost *ExpC* and financial risk cost *λ·CVaR* are the same as Equation 6.5 and Equation 6.7, respectively, as explained in section 6.1.2.1.

$$Min\ Tot = FixC\ (including\ new\ technologies) \quad + ExpC + \lambda \cdot CVaR \tag{6.14}$$

$$Operating_s = \sum_{f,j}(O_f + \Pr_{j,s} \cdot HR_f) \cdot E_f + \sum_{rn} O_{rn} \cdot E_{rn} + \sum_{p,j}(O_p + \Pr_{j,s} \cdot HR_p) \cdot E_p \tag{6.15}$$

$$+\sum_{new}(O_{new} + \Pr_{j,s} \cdot HR_{new}) \cdot E_{new}$$

6.2.2.2 Model Constraints

The minimization of the objective functions represented above is subjected to the following constraints. The model constraints are divided into three parts for deterministic, stochastic and financial risk. The set of constraints include *new technology*, IGCC with and without carbon capture and NGCC with and without carbon capture. The last five constraints for *new technologies* are the same as the deterministic model constraints, such as financial risk constraint (Equation 6.8), energy balance and demand satisfaction constraints (Equations 5.20 – 5.21 and Equations 6.9 – 6.13), capacity constraints (5.7 – 5.10 and Equations 5.22 – 5.24), carbon emission constrains (Equations 5.25 and 5.26) and fuel selection and plant shutdown constrains (Equations 5.13 – 5.14 and Equations 5.27 – 5.36).

6.2.3 Risk Assessment & Analysis

The total cost *TotCost* equals to the summation of *FixC* and *ExpC*. When λ equals 0, it means financial risk management is ignored as only cost is considered to be minimized. When λ equals ∞, it means only financial risk is minimized as total cost is neglected. Therefore, when λ increases from 0 to ∞, the value of total cost increases as value of financial risk decreases. We can see that no matter what λ is, the mixes of power plants chosen to generate electricity are the same. In this report, carbon reduction is 6%.

The impact of the following is covered with *new technologies* in the scope:

- Various penalty values of over-producing and under-producing
- Fuel price increase – sensitivity analysis
- Increase in CO_2 reduction from 6% to 20%

6.2.3.1 Various Penalty Values of Over-Producing & Under-Producing

Various scenarios are considered to see the impact of various penalties of over-production and under-production of electricity generation with *new technologies* on the total cost of electricity and financial risk cost. The impact of the weighting factor $\boldsymbol{\lambda}$ on total cost of electricity and financial risk cost. Based on discussions with energy experts (Appendix A) and keep the industry on low risk, the following two scenarios are considered:

- $C^+ = 20$; $C^- = 200$
- $C^+ = 40$; $C^- = 400$

Scenario 1: $C^+ = 20$; $C^- = 200$

In this scenario, C^+, the shortage of demand or excessive generated power, is assumed to be \$20/MWh. C^-, the excessive demand or shortage of power, is assumed to be \$200/MWh. The results are shown in Tables B.30 and B.31 (Appendix B).

<u>Total Electricity Cost & Financial Risk Cost:</u> By using *new technologies*, the total cost of electricity increases when the weighting factor increases. The trend is the same with existing technologies, which is shown in Figure 6.1. The total cost per year using *new*

technology with financial risk is 0.04% lower than the total per year using existing technologies with financial risk.

The total cost of electricity at the weighting factor 1.0 is \$ 2.6782E+9/yr at 6% CO_2 reduction with *new technologies*, which is the best cost under uncertainties without financial risk. The financial risk cost is \$ 2.7586E+9/yr. The total best cost is 42% higher than the cost of \$1.8892E+9 which is the total cost with *new technologies* and without using electricity uncertainties and financial risk. The financial risk cost is 46% higher than the cost of \$ 1.8892E+9/yr. The results are shown in Table B.30 and Table B.31 (Appendix B). There is a slight change in electricity generation at the various scenarios of penalty values.

<u>Total Electricity Generation:</u> The total electricity generation is 1.2913E+8 MWh with uncertainties and financial risk consideration at 6% CO_2 reduction with *new technologies*. This is 7% more than the electricity generation power of 1.2058E+8 MWh, which is the electricity generation without uncertainty and financial risk consideration. By considering the best uncertain cost, we pay 42% more and produce 7% more than the base load demand at 6% CO_2 reduction. By considering financial risk, we pay 46% more and produce 7% more than the base load demand at 6% CO_2 reduction.

Electricity generation from renewable (nuclear) plants decreases by 5% as the total cost increases and financial risk cost decreases as shown in Table B.31 (Appendix B). The detailed electricity generation distribution is shown in Table B.32 (Appendix B).

***Scenario 2*: C^+ = 40; C^- = 400**

In this scenario, C^+, the shortage of demand or excessive generated power, is assumed to be \$40/MWh. C^-, the excessive demand or shortage of power, is assumed to be \$400/MWh. The results are shown in Tables B.33, Table B.34 and Table B.35 (Appendix B).

<u>Total Electricity Cost & Financial Risk Cost:</u> By using *new technologies*, the total cost of electricity increases when the weighting factor increases. The trend is the same with existing technologies, which is shown in Figure 6.1. The total cost per year using *new technology* with financial risk is 4.6% lower than the total per year using existing technologies with financial risk.

The total cost of electricity at the weighting factor 1.4 is \$ 3.03647E+9/yr at 6% CO_2 reduction with *new technologies*, which is the best cost under uncertainties without financial risk. The financial risk cost is \$ 3.1971E+9/yr. The total best cost is 60% higher than the cost of \$1.8892E+9, which is the total cost with *new technologies* and without using electricity uncertainties and financial risk. The financial risk cost is 69% higher than the cost of \$ 1.8892E+9/yr. The results are shown in Table B.33 (Appendix B). There is a slight change in electricity generation at the various scenarios of penalty values.

<u>Total Electricity Generation:</u> The total electricity generation is 1.2913E+8 MWh with uncertainties and financial risk consideration at 6% CO_2 reduction with *new technologies*. This is 7.1% more than the electricity generation power of 1.2058E+8 MWh, which is the electricity generation without uncertainty and financial risk consideration. By considering the best uncertain cost, we pay 60% more and produce 7.1% more than the base load demand at 6% CO_2 reduction. By considering financial risk, we pay 69% more and produce 7.1% more than the base load demand at 6% CO_2 reduction.

The detailed electricity generation distribution is shown in Table B.35 (Appendix B).

6.2.3.2 Sensitivity Analysis – Fuel Price Increase

To verify the correctness of the stochastic model, the base price fuels (e.g. coal and natural gas) are changed.

First, the base fuel price is increased to 10%. Thus, the base prices for coal and natural gas are \$2.2/GJ and \$6.1/GJ respectively. The corresponding lower prices and higher prices for them are \$1.815/GJ and \$3.025/GJ, \$5.0325/GJ and \$8.3875/GJ respectively. The corresponding results as shown in Tables B.36 and Table B.37 at 10% fuel price increase.

The total best cost increases by 19%, 25% and 28% when the fuel price increases by 10%, 50% and 100%, respectively. The financial cost increases by 21%, 26% and 30% when the fuel price increases by 10%, 50% and 100% as shown in Tables B.36, Table B.39 and Table B.42 (Appendix B).

Total best cost of electricity under uncertainty increases when the weighting factor increases with *new technologies* and various fuel price increases. The trend is the same as with *new technology* without fuel price increases at 6% CO_2 reduction.

The best cost of electricity using *new technology* with uncertainty and a 50% fuel price increase is 29% lower than the total cost using existing technologies without uncertainty at 6% CO_2 reduction.

The total best cost of electricity at the weighting factor 1.4 and 50% fuel price increase is \$ 3.7874E+9/yr at 6% CO_2 reduction. The total best cost at a 50% fuel price increase is 100% higher than the cost of \$ 1.8892E+9/yr, which is total cost with *new technologies* without uncertainty.

The financial risk cost at a fuel price increase is 114% higher than the cost of \$ 1.8892E+9/yr with *new technologies* and without uncertainty and financial risk. This cost is 60% higher than the cost without a 50% fuel price increase 114% vs. 60%) as shown in Tables B.36, Table B.39 and Table B.42 (Appendix B).

The results show that the total best cost under uncertainty and total financial risk cost increase significantly with an increase in fuel price.

The total electricity generation is 1.2785E+8 MWh, 1.2811E+8 MWh and 1.2803E+8 MWh when the fuel price is increased by 10%, 50% and 100%, respectively, at 6% CO_2 reduction. This is 6% more than the electricity generation of 1.2058E+8 MWh, which is the electricity generation without uncertainty and financial risk consideration. By considering the best uncertain demand of electricity and fuel price, we pay 100% more and produce 6% more than the base load demand at a 50% fuel price increase and 6% CO_2 reduction. By considering financial risk, we pay 114% more and produce 6% more than the base load electricity demand at a 50% fuel price increase and 6% CO_2 reduction as shown in Table B.37, Table B.40 and Table B.43 (Appendix B).

At a 10% fuel price increase there is no significant change in electricity load distribution. However, at a 50% fuel price increase the load on new technology IGCC and NGCC plant is increased. At a 100% fuel price increase the load on fossil fuel plants is reduced and load is switched from NGCC to IGCC with CO_2 capture as shown in Table B.38, Table B.41 and table B.44 (Appendix B).

6.2.3.3 Increase in CO_2 Reduction from 6% to 20%

Results were compared between a 6% CO_2 reduction and a 20% CO_2 reduction with *new technologies*. In the scenario, C^+, the cost of over-production or a shortfall in demand was assumed to be \$40/MWh, However, C^-, the more serious case of excessive demand resulting in a shortage of power, was assumed to be \$400/MWh. The results are show in Table B.45 and Table B.46 (Appendix B).

The results show that there is a 4.4% increase in the best total cost under uncertainty and a 4% increase in the financial risk cost when there is an increase CO_2 reduction from 6% to 20%. The total electricity generation is the same at 1.3044E+8 MWh. There is a reduction of fossil power at a weighting factor of 1.0. The reduction in total cost and financial risk cost is due to the higher efficiency and lower operating cost of *new technologies*.

6.2.4 Evaluation of Results & Decision Analysis

6.2.4.1 Total Cost & Electricity Generation under Uncertainty

Figure 6.6 Figure shows the total electricity cost and the financial risk cost versus weighing factor λ with penalty $C^+ = 40$; $C^- = 400$ for various fuel price increases with *new technologies*.

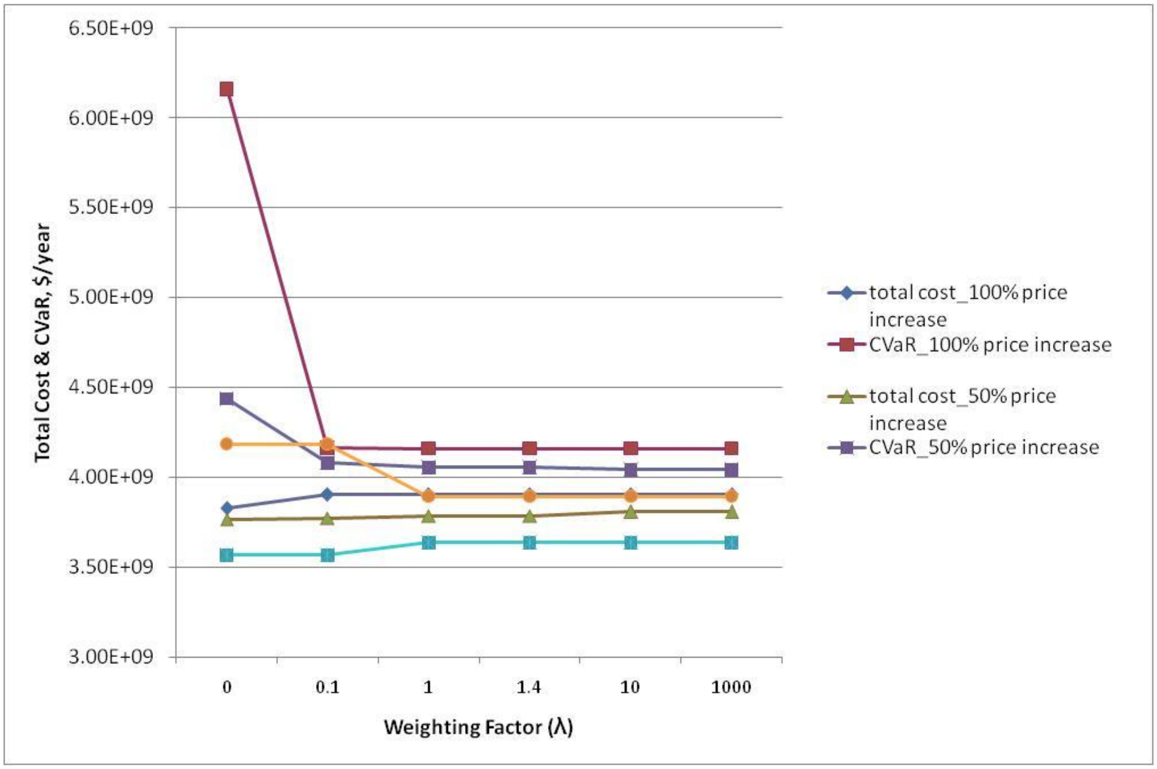


Figure 6.6 Total Cost of Electricity & Financial Risk Cost vs. Weighting Factor λ with Penalty $C^+ = 40$; $C^- = 400$ for Various Fuel Price Increases with *New Technologies*

When the weighting factor increases, the total cost increases and the financial risk cost decreases. After a certain weighing factor λ, there is no impact on the total cost and the financial risk cost. Then the lines become straight. The trend is the same as shown in Figure 6.6 without *new technologies*. The only difference is that the total cost and the financial risk cost decrease with *new technologies* and we have to pay less due to uncertainty and financial risk.

Figure 6.7 Figure shows the total electricity cost and the financial risk cost versus weighing factor λ with penalty $C^+ = 40$; $C^- = 400$ for 50% fuel price increases with *new technologies*.

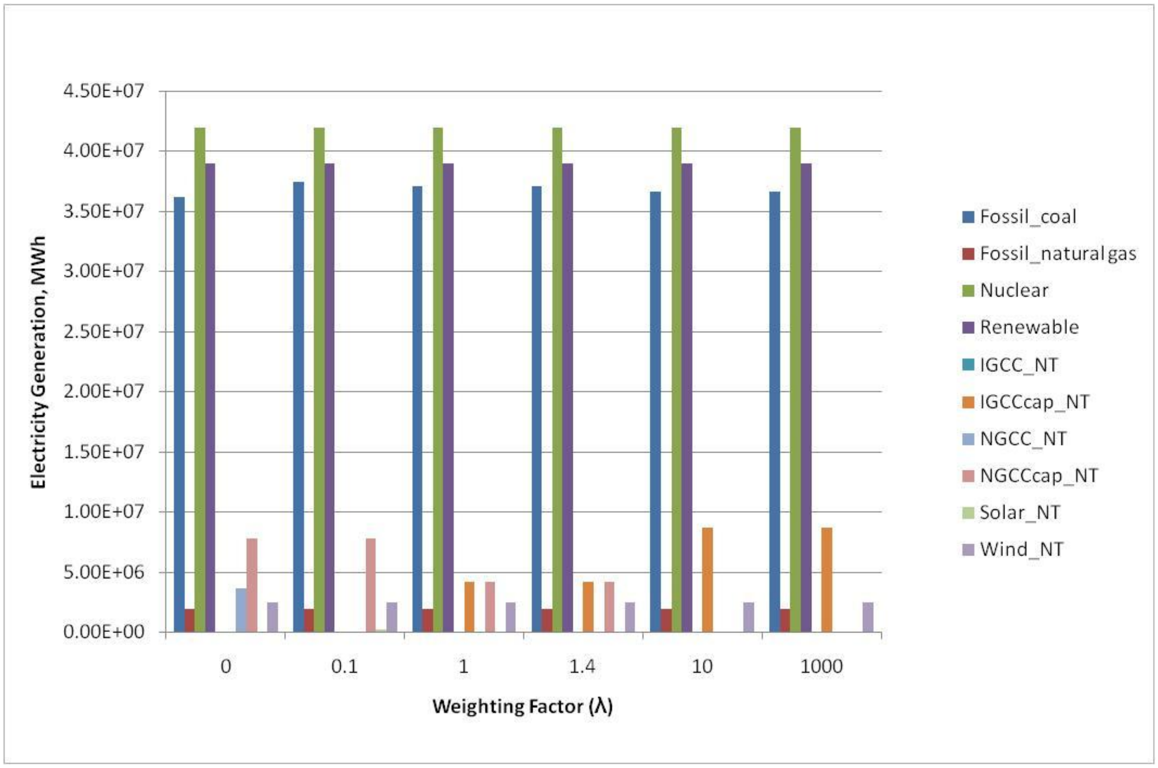


Figure 6.7 Electricity Generation Distribution vs. Weighting Factor *λ* for Various Types of Power Stations with Penalty $C^+ = 40$; $C^- = 400$ and Fuel Price Increase by 50% with *New Technologies*

When the fuel price increases, the total cost and the financial risk cost also increase as explained in Section 6.1.5. As the weighting factor grows, the total cost increases and the financial risk cost decreases.

When the weighting factor increases, the electricity generation at a 10% fuel price increase and there is no significant change in electricity load distribution. At a 50% fuel price increase the load on IGCC with CO_2 capture power plant is increased and the load on NGCC with CO_2 capture is reduced as shown in Figure 6.8. At a 100% fuel price increase the load on fossil fuel plants and nuclear plant increase and the load on IGCC with capture is reduced as shown Tables B.31, B.34 and B.37 (Appendix B).

The total electricity generation is 6% more than the electricity generation without uncertainty and financial risk at the base load demand and 6% CO_2 reduction.

7.0 Conclusions, Contributions and Future Work

In this chapter, a summary of the results of this thesis is given, conclusions are drawn, and future research is envisaged.

7.1 Conclusions

7.1.1 Literature Search & Methodology

Several methodologies were developed during the last three decades. They focus on one or two tools or steps. There are several steps, such as integration of *new technologies*, financial risk management and process reliability analyses, that are not included in these methodologies. However, several techniques and approaches are proposed in the literature to screen alternatives, such as experienced-based approach, application of various optimization methods and in some cases, optimization combined with thermodynamic methods.

There is no set methodology that every industry can use. There is no concept of model development for screening alternatives. Financial risk management and reliability analysis are not part of the industrial methodology. One of the most evident problems in industries is the evaluation and integration of existing plants. The retrofit problem is sometimes difficult because of many constraints such as space, operating conditions, etc. This problem has received little attention in the literature. The work in retrofit design has been limited because of the above difficulties. The same problem could be encountered with integration of *new technology* if a systematic methodology is not used.

One of the main benefits of the proposed methodology is that it guides the decision-maker in a systematic manner through the steps of analyzing the process, identifying technologies, generating options, evaluating options and implementing options.

There is a gap between industry and academia. Very few papers are written and published on real industry problems or by industry experts. Most of the papers are theoretical. Also, there seems to be no thorough review of *new technologies*.

7.1.2 Integration of *New Technologies* – Deterministic Model

Without *new technology*, the maximum CO_2 reduction achieved is 40% at base load demand even with the new fossil plants. Electricity cost increases as demand increases. The slope above 20% CO_2 reduction turns steep because for up to 20% CO_2 reduction, only fossil fuel and renewable power stations are selected; above 20%, the load on new power stations is increased. The power generation from fossil fuel stations remains the same or slight change from 6% to 40% CO_2 reduction due to fuel balancing and switching load from lower efficient power stations to higher efficient stations. The CO_2 reduction cost increases by 12% from 0% to 40% CO_2 reduction at 1% growth in base load demand because of a new NGCC power unit.

Without *new technologies* and at 20% growth in base demand, only up to 6% CO_2 reduction is achieved. The growth is achieved by adjusting the capacity at higher efficiency power stations and new NGCC power units. The total cost and cost of electricity increase by 13%, when fuel price increases by 50% and based load demand increases by 20%. This increase is not proportional to price because of the shifting of the power load from lower efficiency power stations to higher efficiency power stations, shutting down lower efficiency power stations and shifting load from existing power stations to the new NGCC power stations.

Without *new technologies* and with CO_2 constraints, the electricity cost increases as fuel price increases. No matter how much fuel price increases, the slope of electricity cost stays almost the same. The electricity cost increases by 71.6% along with CO_2 emissions as the base load increases to 20% without CO_2 constraints. This is probably due to the additional load given to lower efficiency power stations in order to meet the increased demand. Carbon reduction cost increases as demand growth increases.

With *new technologies*, 60% CO_2 reduction can be achieved. The total cost and cost of electricity increase when CO_2 reduction increases. The increase in electricity cost is lower than increase in electricity cost without new technologies. This is because the *new technology* power stations are more efficient in terms of fuel usage and fuel conversion. The operating cost is also lower than the existing technology power stations.

With *new technology*, the total cost and cost of electricity increase when fuel price increases. The total cost and cost of electricity increase by 1%, when fuel price increases by 10% at base load demand increases by 20%.

Electricity costs with *new technologies* are lower than with existing technologies. The trends are the same at various growths at base load demands. The operating cost and CO_2 emissions are a lot lower than that of existing technologies.

Wind and solar technologies appear to be economical at higher CO_2 reduction levels.. IGCC with capture and NGCC with and without capture were found to be feasible and economical.

The cost of electricity at base case demand with 6% CO_2 reduction is 1.57 ¢/KWh as compared to Linda's optimization 1.57 ¢/KWh. However, with *new technologies*, the electricity cost is 2.24 ¢/KWh at base case load demand with 60% CO_2 reduction versus

Linda's 2.44 ¢/KWh by using CO_2 capture. At 10% growth with 60% CO_2 reduction is 2.77 ¢/KWh versus Linda's 3.37 ¢/KWh by using carbon capture.

7.1.3 Financial Risk Management – Stochastic Model

The total cost, which is a summation of fixed cost and expected cost, increases when the weighting factor increases and financial risk decreases. After a certain level of weighting factor, there is no impact on total cost and financial risk.

Electricity generation from fossil power stations decreases as total cost increases and financial risk decreases. At weighting factor 1.0, the total electricity generation at base load demand with 6% CO_2 reduction without new technologies and with penalty is 1.2857E+8 MWh, and the total cost is $3.0376E+9/year with financial risk. Without financial risk, the electricity generation at base load demand with 6% CO_2 reduction is 1.2058E+8 MWh, and the total cost is a lot lower than the financial risk, which is $1.8893E+9/year. As weighting factor increases, the financial risk management becomes more important, while cost minimization turns less important. The total cost increases by 60% and produce 6.6% more power with financial risk management.

When the weighting factor increases, cost increases, while risk decreases. The total cost of electricity generation includes capital investment, operating cost and penalty cost power over-production or under-production as compared to the demand load. Risk is the expected value of total cost of electricity generation exceeding a certain target and its probability. CVaR is applied to measure the financial risk. However, the objective function value does not change for all changing weighting factors, only certain effective points.

When fuel price increases, total cost and financial risk cost increase accordingly. As the weighting factor grows, the total cost increases and CVaR decreases. Both curves have the same trends.

If demands for different scenarios are the same and the probability for medium fuel price is 1, while others 0, then the total cost and financial risk minimization cost are almost the same as the deterministic model's total cost, which shows that stochastic model is the same as the deterministic model in the sense that the uncertainties are equally known.

With *new technologies*, the trends and concepts are the same as without *new technologies*. However, the total cost of electricity is lower than that of existing technologies due to lower operating cost and higher efficiency. The trends are the same as the deterministic model.

7.2 Contributions

A new methodology is proposed to obtain potential process improvement with addition of so-called *new technologies*, while minimizing financial risks. Application of a *new technology* is always perceived as a potential threat. Therefore, financial risk assessment and reliability risk analysis help alleviate risks of investment.

New technologies offer new opportunities and are crucial for profitable growth. The broad-spectrum technologies open up new and attractive business opportunities for the customers. However, to be used effectively, the *new technologies* must be carefully selected and integrated to match the complex requirements of an overall process and achieve the required results. The new proposed methodology will help to develop and apply a systematic process for the integration of various improvement options, including *new technologies*, into the existing mature processes.

The research contributes to the understanding of financial risk management of the selected options and technologies in supporting the decision process. The model was modified to incorporate financial risk management in order to pursue financial risks associated with selected options and their influence on the decision-making process.

An industrial problem was selected as a case study for the validation of the methodology and application of *new technology*. Evaluation is based on knowledge gained from industrial experience.

7.3 Recommendations for Future Work

The following are recommendations for future work:

7.3.1 Further Testing and Improvement of the Methodology

The one case study is considered to validate the methodology. The real industrial problem in the power generation sector was selected for the validation of methodology, and *new technologies* in energy are integrated and evaluated based on industrial experience and available data. However, there is a need to benchmark this methodology with the real industrial problems in other industrial sectors, such as petrochemical and refining areas. This would include an assessment of how the proposed methodology integrates with the values and benefits from the existing plant data and information gathering systems, process models, controls and operational experience. We also need to automate the different steps in the methodology by taking advantage of package software and spreadsheet programs.

7.3.2 Generation of Multiple Incentives & Evaluation of Alternatives

The new methodology presented covers only the incentives of improving the production efficiency, reducing energy and reducing operating costs. A considerable number of other benefits exist, such as the improvement of reliability, improvement of plant service factor, improvement of environmental performance, improvement of safety, improvement of flexibility and others. These incentives are not covered in overall incentive programs of the methodology. There is an opportunity to extend this research to find methods to quantify these incentives, and the research potential could be extended to include other incentives.

The total cost impact of potential structured alternatives can only be viewed as an order-of-magnitude estimation of the attainable cost savings. Therefore, it would be desirable to refine this indicator so that actual cost savings can be calculated. Such an indicator could be used effectively to reduce the number of alternatives to be studied in the detailed evaluation procedure. The standard packages could be used to make these accurate estimates.

In this methodology, operability and the safety and environmental impact on the improved design were particularly considered. Safety and environmental concerns change conceptual process design. They bring about extended system boundaries, inherent multi-objectivity and more constraints. All these changes influence further screening of reaction path, generation of flow sheet alternatives and solution of safety and environmental criteria and optimization methods.

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Appendix A

Integration of *New Technologies* – Industry Methodology

A.1 Questionnaire

1. Does the attached Current Industrial Methodology (CIM) reasonably represent the methodology used in your industry? (Yes/No)

2. If not, what are the major differences between the CIM and the approach used in your industry?

3. What are the major weaknesses in the CIM that you would like to see improved in a new methodology?

- Financial risk management
- Reliability identification and analysis
- Screening and ranking of new alternatives and technologies by using a model
- Business case development
- Decision analysis

4. Do you have any additional comments?

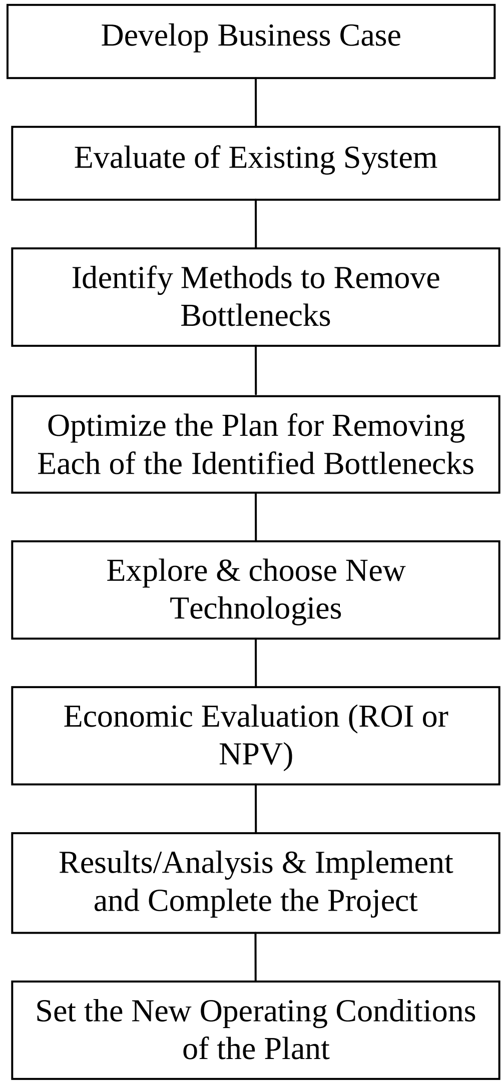

Figure A.1 Current Industrial Methodology

A.2 Responses

A.2.1 Response 1

Respondent 1 has over 35 years of experience in the chemical process industries in various capacities. His areas of expertise have been technology transfer in chemical and petrochemical industries while he was with Stauffer and European Vinyl Corporation (EVC). He has completed a number of projects in Europe, Africa, India and the USA. He is currently working as a process engineering consultant with Kellogg Brown Root (KBR) Company in Delaware.

1. Does the attached Current Industrial Methodology (CIM) reasonably represent the methodology used in your industry? (Yes/No)

   Yes

2. If not, what are the major differences between the CIM and the approach used in your industry?

   A major weakness is the assessment of new technology *that is being considered for integration in old plants. The* new technology *may be great, but it may require complete revamping of the current equipment in an old plant. There is a financial risk because sometimes it may cost more than a new plant. Financial risk management is a critical part missing in the methodology.*

   So the new technology *must be carefully evaluated for integration. This applies to the process as well as the control systems.*

3. What are the major weaknesses in the CIM that you would like to see improved in a new methodology?

- Financial risk management
- Reliability identification and analysis
- Screening and ranking of new alternatives and technologies by using a model
- Business case development
- Decision analysis

Financial risk management and reliability analysis must be completed.

Screening and ranking of new alternatives by using a model must be completed. Before using a model, the basic parameters and ultimate outcome (energy savings, better yield, less cycle time, increased capacity, etc.) must be established.

Business case development must consider global competition. If the same product or service can be provided in other country at a lower cost, then the project will become unprofitable.

4. Do you have any additional comments?

    No comments

A.2.2 Response 2

Respondent 2 has over 36 years of experience in chemicals, refining and ethylene plants in various capacities. He retired from Shell as a technical advisor. Currently, he is working as a consultant with Fluor Company on major projects.

1. Does the attached Current Industrial Methodology (CIM) reasonably represent the methodology used in your industry? (Yes/No)

   Yes

2. If not, what are the major differences between the CIM and approach used in your industry?

3. What are the major weaknesses in the CIM that you would like to see improved in a new methodology?

- Financial risk management
- Reliability identification and analysis
- Screening and ranking of new alternatives and technologies by using a model
- Business case development
- Decision analysis

In the current CIM plan as shown, there is no mention on how to evaluate the current system and identify bottlenecks. In industry, the methodology is very simple. All of the above should be an integral part of evaluating and integrating new technologies *and their application to the existing systems.*

4. Do you have any additional comments?

   The attached industrial methodology is a typical system used in industry for the evaluation and application of new technology. *What is confusing is one starts with analysis of an existing system and leads into new/alternate technology application. There is no rigorous mathematical evaluation of various alternatives* *and evaluation of risks. This could be because the staff is not trained in these tools. Therefore, the decisions for investment are not sound.*

A.2.3 Response 3

Respondent 3 has over 30 years of experience in the energy industries and petrochemical industries in various capacities at Bechtel Corporation and Dynegy Energy. He handled major projects in both energy and petrochemical areas. He is currently working for Worley Parson as a project director.

1. Does the attached Current Industrial Methodology (CIM) reasonably represent the methodology used in your industry? (Yes/No)

   Yes

   The industry methodology represents the introduction of a new technology *based on a business case. However, the industry is based on real life problems, which are a combination of technical, environmental and financial problems. These drivers have an important bearing on the approach used to resolve problems.*

2. If not, what are the major differences between the CIM and the approach used in your industry?

3. What are the major weaknesses in the CIM that you would like to see improved in a new methodology?

- Financial risk management
- Reliability identification and analysis
- Screening and ranking of new alternatives and technologies by using a model
- Business case development
- Decision analysis

The major component I would like to see is a very clear definition of the problems, goals and final objectives to be achieved. These should include technical, financial risk, business and resource issues. A rigorous market analysis and evaluation of alternatives should supplement the overlying premise. Technology alternatives and their feasibility should be addressed realistically. Non-realistic technologies need to be screened out.

4. Do you have any additional comments?

   New feasible technologies must translate into practical solutions over a finite period of time. The practicality of a solution will determine its long term potential and ease of implementation.

Appendix B

Distribution of Load & Cost in Selected Power Plants

B.1 Deterministic Model – without *New Technologies*

Table B.1 Electricity Generation Distribution for Various Types of Power Stations without CO_2 Emission Constraint and without *New Technologies*

Power Stations	Base Load (MWh)	1% Growth (MWh)	5% Growth (MWh)	10% Growth (MWh)	20% Growth (MWh)
Lambton	1.0122E+7	1.0122E+7	1.0122E+7	9.6011E+6	1.0122E+7
Nanticoke	2.2378E+7	2.2378E+7	2.2378E+7	2.2378E+7	2.2378E+7
Atitokan	8.3123E+5	8.3123E+5	8.3123E+5	8.3123E+5	8.3123E+5
Lakeview	2.1696E+6	2.4796E+6	1.3322E+6	9.9689E+5	2.4796E+6
Lennox	1.8938E+6	2.7896E+6	1.8746E+6	1.8746E+6	2.7896E+6
Thunder Bay	1.5049E+6	1.5049E+6	1.5049E+6	1.5049E+6	1.5049E+6
Nuclear	4.2319E+7	4.2319E+7	4.2319E+7	4.2319E+7	4.2319E+7
Hydro	3.8639E+7	3.8639E+7	3.8639E+7	3.8639E+7	3.8639E+7
Wind	7.2013E+5	7.2013E+5	7.2013E+5	7.2013E+5	7.2013E+5
Coal11_new	0	0	0	0	0
Coal12_new	0	0	0	0	0
Coal13_new	0	0	0	0	0
Coal14_new	0	0	0	0	0
Coal21_new	0	0	3.4427E+6	3.4427E+6	3.4427E+6
Coal22_new	0	0	3.4427E+6	3.4427E+6	3.4427E+6
Coal23_new	0	0	0	3.4427E+6	3.4427E+6
Coal24_new	0	0	0	3.4427E+6	3.4427E+6
NGCC11_new	0	0	0	0	0
NGCC12_new	0	0	0	0	0
NGCC13_new	0	0	0	0	0
NGCC14_ new	0	0	0	0	0
NGCC21_ new	0	0	0	0	0
NGCC22_ new	0	0	0	0	0
NGCC23_ new	0	0	0	0	0
NGCC24_ new	0	0	0	0	0
NGCC31_ new	0	0	0	0	3.3310E+6
NGCC32_ new	0	0	0	0	3.3310E+6
NGCC33_ new	0	0	0	0	2.4769E+6
NGCC34_ new	0	0	0	0	0

Table B.2 Electricity Generation Distribution for Various Types of Power Stations vs. Various CO_2 Emission Constraints with Base Load and without *New Technologies*

Power Stations	0% CO_2 Reduction (MWh)	6% CO_2 Reduction (MWh)	20% CO_2 Reduction (MWh)	40% CO_2 Reduction (MWh)
Lambton	1.0122E+7	1.0122E+7	1.0122E+7	1.0122E+7
Nanticoke	2.2378E+7	2.2378E+7	2.2378E+7	2.2378E+7
Atitokan	8.3123E+5	8.3123E+5	8.3123E+5	8.3123E+5
Lakeview	2.1696E+6	2.1696E+6	1.4772E+6	2.1696E+6
Lennox	1.8938E+6	1.8938E+6	2.5862E+6	1.8938E+6
Thunder Bay	1.5049E+6	1.5049E+6	1.5049E+6	1.5049E+6
Nuclear	4.2319E+7	4.2319E+7	4.2319E+7	4.2319E+7
Hydro	3.8639E+7	3.8639E+7	3.8639E+7	3.8639E+7
Wind	7.2013E+5	7.2013E+5	7.2013E+5	7.2013E+5
Coal11_new	0	0	0	0
Coal12_new	0	0	0	0
Coal13_new	0	0	0	0
Coal14_new	0	0	0	0
Coal21_new	0	0	0	0
Coal22_new	0	0	0	0
Coal23_new	0	0	0	0
Coal24_new	0	0	0	0
NGCC11_new	0	0	0	0
NGCC12_new	0	0	0	0
NGCC13_new	0	0	0	0
NGCC14_ new	0	0	0	0
NGCC21_ new	0	0	0	0
NGCC22_ new	0	0	0	0
NGCC23_ new	0	0	0	0
NGCC24_ new	0	0	0	0
NGCC31_ new	0	0	0	0
NGCC32_ new	0	0	0	0
NGCC33_ new	0	0	0	0
NGCC34_ new	0	0	0	0

Table B.3 Electricity Generation Distribution for Various Types of Power Stations vs. Various CO_2 Emission Constraints with 1% Growth in Base Load Demand and without *New Technologies*

Power Stations	0% CO_2 Reduction (MWh)	6% CO_2 Reduction (MWh)	20% CO_2 Reduction (MWh)	40% CO_2 Reduction (MWh)
Lambton	1.0122E+7	1.0122E+7	1.0122E+7	1.0122E+7
Nanticoke	2.2378E+7	2.2378E+7	2.2378E+7	2.2378E+7
Atitokan	8.3123E+5	8.3123E+5	8.3123E+5	8.3123E+5
Lakeview	2.4796E+6	2.4796E+6	2.4410E+6	1.0587E+6
Lennox	2.7896E+6	2.7896E+6	1.8746E+6	1.8746E+6
Thunder Bay	1.5049E+6	1.5049E+6	1.5049E+6	1.5049E+6
Nuclear	4.2319E+7	4.2319E+7	4.2319E+7	4.2319E+7
Hydro	3.8639E+7	3.8639E+7	3.8639E+7	3.8639E+7
Wind	7.2013E+5	7.2013E+5	7.2013E+5	7.2013E+5
Coal11_new	0	0	0	0
Coal12_new	0	0	0	0
Coal13_new	0	0	0	0
Coal14_new	0	0	0	0
Coal21_new	0	0	0	0
Coal22_new	0	0	0	0
Coal23_new	0	0	0	0
Coal24_new	0	0	0	0
NGCC11_new	0	0	0	0
NGCC12_new	0	0	0	0
NGCC13_new	0	0	0	0
NGCC14_ new	0	0	0	0
NGCC21_ new	0	0	0	0
NGCC22_ new	0	0	0	0
NGCC23_ new	0	0	0	0
NGCC24_ new	0	0	0	0
NGCC31_ new	0	0	9.5352E+5	2.3359E+6
NGCC32_ new	0	0	0	0
NGCC33_ new	0	0	0	0
NGCC34_ new	0	0	0	0

Table B.4 Electricity Generation Distribution for Various Types of Power Stations vs. Various CO_2 Emission Constraints with 5% Growth in Base Load Demand and without *New Technologies*

Power Stations	0% CO_2 Reduction (MWh)	6% CO_2 Reduction (MWh)	20% CO_2 Reduction (MWh)	40% CO_2 Reduction (MWh)
Lambton	1.0122E+7	1.0122E+7	1.0122E+7	6.5494E+6
Nanticoke	2.2378E+7	2.2378E+7	2.2378E+7	1.9732E+7
Atitokan	8.3123E+5	8.3123E+5	8.3123E+5	0
Lakeview	1.8397E+6	2.2235E+6	2.4758E+6	0
Lennox	1.8746E+6	1.8746E+6	1.8746E+6	2.0661E+6
Thunder Bay	1.5049E+6	1.5049E+6	1.5049E+6	0
Nuclear	4.2319E+7	4.2319E+7	4.2319E+7	4.2319E+7
Hydro	3.8639E+7	3.8639E+7	3.8639E+7	3.8639E+7
Wind	7.2013E+5	7.2013E+5	7.2013E+5	7.2013E+5
Coal11_new	0	0	0	0
Coal12_new	0	0	0	0
Coal13_new	0	0	0	0
Coal14_new	0	0	0	0
NGCC11_ new	0	0	0	0
NGCC12_ new	0	0	0	0
NGCC13_ new	0	0	0	0
NGCC14_ new	0	0	0	0
NGCC21_ new	0	0	0	2.1334E+6
NGCC22_ new	0	0	0	2.5952E+6
NGCC23_ new	0	0	0	2.5952E+6
NGCC24_ new	0	0	0	2.5952E+6
NGCC31_ new	3.0469E+6	2.6631E+6	2.4108E+6	3.3310E+6
NGCC32_ new	3.3310E+6	3.3310E+6	3.3310E+6	3.3310E+6
NGCC33_ new	0	0	0	0
NGCC34_ new	0	0	0	0

Table B.5 Electricity Generation Distribution for Various Types of Power Stations vs. Various CO_2 Emission Constraints with 10% Growth in Base Load Demand and without *New Technologies*

Power Stations	0% CO_2 Reduction (MWh)	6% CO_2 Reduction (MWh)	20% CO_2 Reduction (MWh)	30% CO_2 Reduction (MWh)
Lambton	1.0122E+7	1.0122E+7	1.0122E+7	1.0122E+7
Nanticoke	2.2378E+7	2.2378E+7	2.2378E+7	2.2378E+7
Atitokan	8.3123E+5	8.3123E+5	8.3123E+5	0
Lakeview	1.8822E+6	2.1946E+6	2.4796E+6	0
Lennox	1.8746E+6	1.8746E+6	2.7896E+6	1.8746E+6
Thunder Bay	1.5049E+6	1.5049E+6	1.5049E+6	5.8699E+5
Nuclear	4.2319E+7	4.2319E+7	4.2319E+7	4.2319E+7
Hydro	3.8639E+7	3.8639E+7	3.8639E+7	3.8639E+7
Wind	7.2013E+5	7.2013E+5	7.2013E+5	7.2013E+5
Coal11_ new	0	0	0	0
Coal 12_ new	0	0	0	0
Coal 13_ new	0	0	0	0
Coal 14_ new	0	0	0	0
NGCC11_ new	0	0	0	0
NGCC12_ new	0	0	0	0
NGCC13_ new	0	0	0	0
NGCC14_ new	0	0	0	0
NGCC21_ new	0	0	0	0
NGCC22_ new	0	0	0	76485.685
NGCC23_ new	0	0	0	0
NGCC24_ new	0	0	0	2.5952E+6
NGCC31_ new	2.3713E+6	2.0589E+6	8.5896E+5	3.3310E+6
NGCC32_ new	3.3310E+6	3.3310E+6	3.3310E+6	3.3310E+6
NGCC33_ new	3.3310E+6	3.3310E+6	3.3310E+6	3.3310E+6
NGCC34_ new	3.3310E+6	3.3310E+6	3.3310E+6	3.3310E+6

Table B.6 Electricity Generation Distribution for Various Types of Power Stations vs. Various CO_2 Emission Constraints with 20% Growth in Base Load Demand and without *New Technologies*

Power Stations	0% CO_2 Reduction (MWh)	6% CO_2 Reduction (MWh)
Lambton	1.0122E+7	1.0122E+7
Nanticoke	2.2378E+7	2.2378E+7
Atitokan	8.3123E+5	8.3123E+5
Lakeview	2.4796E+6	2.4796E+6
Lennox	2.7896E+6	2.7418E+6
Thunder Bay	1.5049E+6	1.5049E+6
Nuclear	4.2319E+7	4.2319E+7
Hydro	3.8639E+7	3.8639E+7
Wind	7.2013E+5	7.2013E+5
Coal11_ new	0	0
Coal 21_ new	0	0
Coal 22_ new	0	0
Coal 23_ new	0	0
NGCC11_ new	0	0
NGCC12_ new	0	0
NGCC13_ new	0	0
NGCC14_ new	0	0
NGCC21_ new	2.5952E+6	2.5952E+6
NGCC22_ new	2.5952E+6	2.5952E+6
NGCC23_ new	2.5952E+6	2.5952E+6
NGCC24_ new	1.8002E+6	1.8480E+6
NGCC31_ new	3.3310E+6	3.3310E+6
NGCC32_ new	3.3310E+6	3.3310E+6
NGCC33_ new	3.3310E+6	3.3310E+6
NGCC34_ new	3.3310E+6	3.3310E+6

Table B.7 Electricity Generation Distribution for Various Types of Power Stations vs. Various Aggregated Growth Demands with 10% Fuel Price Increase and 6% CO_2 Reduction without *New Technologies*

Power Stations	Base Load (MWh)	1% Growth (MWh)	5% Growth (MWh)	10% Growth (MWh)	20% Growth (MWh)
Lambton	1.0122E+7	1.0122E+7	1.0122E+7	1.0122E+7	1.0122E+7
Nanticoke	2.2378E+7	2.2378E+7	2.2378E+7	2.2378E+7	2.2378E+7
Atitokan	8.3123E+5	8.3123E+5	8.3123E+5	8.3123E+5	8.3123E+5
Lakeview	2.1696E+6	2.4796E+6	2.2235E+6	2.1946E+6	2.4796E+6
Lennox	1.8938E+6	2.7896E+6	1.8746E+6	2.1946E+6	2.7418E+6
Thunder Bay	1.5049E+6	1.5049E+6	1.5049E+6	1.5049E+6	1.5049E+6
Nuclear	4.2319E+7	4.2319E+7	4.2319E+7	4.2319E+7	4.2319E+7
Hydro	3.8639E+7	3.8639E+7	3.8639E+7	3.8639E+7	3.8639E+7
Wind	7.2013E+5	7.2013E+5	7.2013E+5	7.2013E+5	7.2013E+5
Coal11_new	0	0	0	0	0
Coal12_new	0	0	0	0	0
Coal13_new	0	0	0	0	0
Coal14_new	0	0	0	0	0
Coal21_new	0	0	0	0	0
Coal22_new	0	0	0	0	0
Coal23_new	0	0	0	0	0
Coal24_new	0	0	0	0	0
NGCC11_new	0	0	0	0	0
NGCC12_new	0	0	0	0	0
NGCC13_new	0	0	0	0	0
NGCC14_ new	0	0	0	0	0
NGCC21_ new	0	0	0	0	2.5952E+6
NGCC22_ new	0	0	0	0	2.5952E+6
NGCC23_ new	0	0	0	0	2.5952E+6
NGCC24_ new	0	0	0	0	1.8480E+6
NGCC31_ new	0	0	2.6631E+6	2.0589E+6	3.3310E+6
NGCC32_ new	0	0	3.3310E+6	3.3310E+6	3.3310E+6
NGCC33_ new	0	0	0	3.3310E+6	3.3310E+6
NGCC34_ new	0	0	0	3.3310E+6	3.3310E+6

Table B.8 Electricity Generation Distribution for Various Types of Power Stations vs. Various Aggregated Growth Demands with 50% Fuel Price Increase and 6% CO_2 Reduction without *New Technologies*

Demand Growth	Base Load (MWh)	1% Growth (MWh)	5% Growth (MWh)	10% Growth (MWh)	20% Growth (MWh)
Lambton	1.0122E+7	1.0122E+7	1.0122E+7	1.0122E+7	1.0122E+7
Nanticoke	2.2378E+7	2.2378E+7	2.2378E+7	2.2378E+7	2.2378E+7
Atitokan	8.3123E+5	8.3123E+5	8.3123E+5	8.3123E+5	8.3123E+5
Lakeview	2.1696E+6	2.4796E+6	1.8436E+6	1.8105E+6	2.4796E+6
Lennox	1.8938E+6	2.7896E+6	2.7896E+6	2.7896E+6	2.7896E+6
Thunder Bay	1.5049E+6	1.5049E+6	1.5049E+6	1.5049E+6	1.5049E+6
Nuclear	4.2319E+7	4.2319E+7	4.2319E+7	4.2319E+7	4.2319E+7
Hydro	3.8639E+7	3.8639E+7	3.8639E+7	3.8639E+7	3.8639E+7
Wind	7.2013E+5	7.2013E+5	7.2013E+5	7.2013E+5	7.2013E+5
Coal11_new	0	0	0	0	0
Coal12_new	0	0	0	0	0
Coal13_new	0	0	0	0	0
Coal14_new	0	0	0	0	0
Coal21_new	0	0	0	0	0
Coal22_new	0	0	0	0	0
Coal23_new	0	0	0	0	2.8667E+6
Coal24_new	0	0	0	0	3.4427E+6
NGCC11_new	0	0	2.1281E+6	1.5280E+6	0
NGCC12_new	0	0	0	0	0
NGCC13_new	0	0	0	0	0
NGCC14_ new	0	0	0	0	0
NGCC21_ new	0	0	0	0	0
NGCC22_ new	0	0	0	0	2.5952E+6
NGCC23_ new	0	0	0	0	0
NGCC24_ new	0	0	0	0	6.8111E+5
NGCC31_ new	0	0	0	0	3.3310E+6
NGCC32_ new	0	0	3.3310E+6	3.3310E+6	3.3310E+6
NGCC33_ new	0	0	0	3.3310E+6	3.3310E+6
NGCC34_ new	0	0	0	3.3310E+6	3.3310E+6

Table B.9 Electricity Generation Distribution for Various Types of Power Stations vs. Various Aggregated Growth Demands with 100% Fuel Price Increase and 6% CO_2 Reduction without *New Technologies*

Demand Growth	Base Load (MWh)	1% Growth (MWh)	5% Growth (MWh)	10% Growth (MWh)	20% Growth (MWh)
Lambton	1.0122E+7	1.0122E+7	1.0122E+7	1.0122E+7	1.0122E+7
Nanticoke	2.2378E+7	2.2378E+7	2.2378E+7	2.2378E+7	2.2378E+7
Atitokan	8.3123E+5	8.3123E+5	8.3123E+5	8.3123E+5	8.3123E+5
Lakeview	2.1696E+6	2.4796E+6	2.4796E+6	2.4796E+6	2.4796E+6
Lennox	1.8938E+6	2.7896E+6	2.7896E+6	2.7896E+6	2.7896E+6
Thunder Bay	1.5049E+6	1.5049E+6	1.5049E+6	1.5049E+6	1.5049E+6
Nuclear	4.2319E+7	4.2319E+7	4.2319E+7	4.2319E+7	4.2319E+7
Hydro	3.8639E+7	3.8639E+7	3.8639E+7	3.8639E+7	3.8639E+7
Wind	7.2013E+5	7.2013E+5	7.2013E+5	7.2013E+5	7.2013E+5
Coal11_new	0	0	0	0	0
Coal12_new	0	0	0	0	0
Coal13_new	0	0	0	0	0
Coal14_new	0	0	0	0	0
Coal21_new	0	0	0	0	0
Coal22_new	0	0	0	0	0
Coal23_new	0	0	0	0	2.8667E+6
Coal24_new	0	0	3.4427E+6	0	3.4427E+6
NGCC11_new	0	0	3.4427E+6	5.2389E+5	0
NGCC12_new	0	0	0	0	0
NGCC13_new	0	0	0	0	0
NGCC14_ new	0	0	0	0	0
NGCC21_ new	0	0	0	0	0
NGCC22_ new	0	0	0	0	2.5952E+6
NGCC23_ new	0	0	0	0	0
NGCC24_ new	0	0	0	0	6.8111E+5
NGCC31_ new	0	0	0	0	3.3310E+6
NGCC32_ new	0	0	0	0	3.3310E+6
NGCC33_ new	0	0	0	0	3.3310E+6
NGCC34_ new	0	0	0	0	3.3310E+6

B.2 Deterministic Model – with *New Technologies*

Table B.10 Electricity Generation Distribution for Various Types of Power Station vs. Various CO_2 Emission Constraints with Base Load and with *New Technologies*

Power Stations	0% CO_2 Reduction (MWh)	6% CO_2 Reduction (MWh)	20% CO_2 Reduction (MWh)	40% CO_2 Reduction (MWh)	60% CO_2 Reduction (MWh)
Lambton	1.0122E+7	1.0122E+7	1.0122E+7	1.0028E+7	6.5494E+6
Nanticoke	2.2378E+7	2.2378E+7	2.2378E+7	2.2378E+7	1.5245E+7
Atitokan	8.3123E+5	8.3123E+5	8.3123E+5	8.3123E+5	0
Lakeview	2.1888E+6	2.1751E+6	8.7476E+5	9.6903E+5	0
Lennox	1.8746E+6	1.8883E+6	1.8746E+6	1.8746E+6	1.8746E+6
Thunder Bay	1.5049E+6	1.5049E+6	1.5049E+6	1.5049E+6	0
Nuclear	4.2319E+7	4.2319E+7	4.2319E+7	4.2319E+7	4.2319E+7
Hydro	3.8639E+7	3.8639E+7	3.8639E+7	3.8639E+7	3.8639E+7
Wind	7.2013E+5	7.2013E+5	7.2013E+5	7.2013E+5	7.2013E+5
IGCC1_ NT	0	0	0	0	0
IGCC2_ NT	0	0	0	0	0
IGCC3_ NT	0	0	0	0	0
NGCC1_ NT	0	0	0	0	0
NGCC2_ NT	0	0	0	0	0
NGCC3_ NT	0	0	0	0	5.0627E+6
IGCCc1_ NT	0	0	0	0	0
IGCCc2_ NT	0	0	0	0	0
IGCCc3_ NT	0	0	0	0	0
NGCCc1_ NT	0	0	0	0	0
NGCCc2_ NT	0	0	0	0	3.5890E+6
NGCCc3_ NT	0	0	0	0	4.1698E+6
Solar1_NT	0	0	0	0	0
Solar2_NT	0	0	0	0	0
Wind1_NT	0	0	0	0	1.0950E+6
Wind2_NT	0	0	1.3140E+6	1.3140E+6	1.3140E+6

Table B.11 Electricity Generation Distribution for Various Types of Power Stations vs. Various CO_2 Emission Constraints with 1% Growth in Base Load Demand and with *New Technologies*

Power Stations	0% CO_2 Reduction (MWh)	6% CO_2 Reduction (MWh)	20% CO_2 Reduction (MWh)	40% CO_2 Reduction (MWh)	60% CO_2 Reduction (MWh)
Lambton	1.0122E+7	1.0122E+7	1.0122E+7	1.0122E+7	6.5494E+6
Nanticoke	2.2378E+7	2.2378E+7	2.2378E+7	2.2378E+7	1.2631E+7
Atitokan	8.3123E+5	8.3123E+5	8.3123E+5	8.3123E+5	0
Lakeview	2.4796E+6	2.0805E+6	2.0656E+6	2.0805E+6	0
Lennox	2.7896E+6	1.8746E+6	1.8896E+6	1.8746E+6	1.8746E+6
Thunder Bay	1.5049E+6	1.5049E+6	1.5049E+6	1.5049E+6	0
Nuclear	4.2319E+7	4.2319E+7	4.2319E+7	4.2319E+7	4.2319E+7
Hydro	3.8639E+7	3.8639E+7	3.8639E+7	3.8639E+7	3.8639E+7
Wind	7.2013E+5	7.2013E+5	7.2013E+5	7.2013E+5	7.2013E+5
IGCC1_ NT	0	0	0	0	0
IGCC2_ NT	0	0	0	0	0
IGCC3_ NT	0	0	0	0	0
NGCC1_ NT	0	0	0	0	3.5741E+6
NGCC2_ NT	0	0	0	0	4.1698E+6
NGCC3_ NT	0	0	0	0	4.7278E+6
IGCCc1_ NT	0	0	0	0	0
IGCCc2_ NT	0	0	0	0	0
IGCCc3_ NT	0	0	0	0	0
NGCCc1_ NT	0	0	0	0	0
NGCCc2_ NT	0	0	0	0	0
NGCCc3_ NT	0	0	0	0	4.1698E+6
Solar1_NT	0	0	0	0	0
Solar2_NT	0	0	0	0	
Wind1_NT	0	0	0	0	1.0950E+6
Wind2_NT	0	1.3140E+6	1.3140E+6	1.3140E+6	1.3140E+6

Table B.12 Electricity Generation Distribution for Various Types of Power Stations vs. Various CO_2 Emission Constraints with 5% Growth in Base Load Demand and with *New Technologies*

Power Stations	0% CO_2 Reduction (MWh)	6% CO_2 Reduction (MWh)	20% CO_2 Reduction (MWh)	40% CO_2 Reduction (MWh)	60% CO_2 Reduction (MWh)
Lambton	1.0122E+7	1.0122E+7	1.0122E+7	1.0122E+7	6.5494E+6
Nanticoke	2.2378E+7	2.2378E+7	2.2378E+7	2.2378E+7	1.3795E+7
Atitokan	8.3123E+5	8.3123E+5	8.3123E+5	8.3123E+5	0
Lakeview	2.4796E+6	2.3967E+6	2.3815E+6	4.7142E+5	0
Lennox	2.1289E+6	1.8746E+6	1.8746E+6	1.8746E+6	1.8746E+6
Thunder Bay	1.5049E+6	1.5049E+6	1.5049E+6	1.5049E+6	0
Nuclear	4.2319E+7	4.2319E+7	4.2319E+7	4.2319E+7	4.2319E+7
Hydro	3.8639E+7	3.8639E+7	3.8639E+7	3.8639E+7	3.8639E+7
Wind	7.2013E+5	7.2013E+5	7.2013E+5	7.2013E+5	7.2013E+5
IGCC1_ NT	0	0	0	0	0
IGCC2_ NT	0	0	0	0	0
IGCC3_ NT	0	0	0	0	0
NGCC1_ NT	0	3.4119E+6	3.4271E+6	0	3.5741E+6
NGCC2_ NT	4.1698E+6	0	0	0	4.1698E+6
NGCC3_ NT	0	0	0	5.1510E+6	1.5061E+6
IGCCc1_ NT	0	0	0	0	0
IGCCc2_ NT	0	0	0	0	0
IGCCc3_ NT	0	0	0	0	0
NGCCc1_ NT	0	0	0	0	3.2911E+6
NGCCc2_ NT	0	0	0	0	3.5890E+6
NGCCc3_ NT	0	0	0	0	4.1698E+6
Solar1_NT	0	0	0	1.8615E+5	0
Solar2_NT	0	0	0	0	0
Wind1_NT	0	1.0950E+6	1.0950E+6	1.0950E+6	1.0950E+6
Wind2_NT	1.3140E+6	1.3140E+6	1.3140E+6	1.3140E+6	1.3140E+6

Table B.13 Electricity Generation Distribution for Various Types of Power Stations vs. Various CO_2 Emission Constraints with 10% Growth in Base Load Demand and with *New Technologies*

Power Stations	0% CO_2 Reduction (MWh)	6% CO_2 Reduction (MWh)	20% CO_2 Reduction (MWh)	40% CO_2 Reduction (MWh)	60% CO_2 Reduction (MWh)
Lambton	1.0122E+7	1.0122E+7	1.0122E+7	9.0330E+6	6.5494E+6
Nanticoke	2.2378E+7	2.2378E+7	2.2378E+7	2.2378E+7	1.1428E+7
Atitokan	8.3123E+5	8.0404E+5	8.3123E+5	8.3123E+5	0
Lakeview	2.4466E+6	2.4796E+6	2.4759E+6	0	0
Lennox	1.8835E+6	1.8778E+6	1.8746E+6	1.8746E+6	1.8746E+6
Thunder Bay	1.5049E+6	1.5049E+6	1.5049E+6	1.5049E+6	0
Nuclear	4.2319E+7	4.2319E+7	4.2319E+7	4.2319E+7	4.2319E+7
Hydro	3.8639E+7	3.8639E+7	3.8639E+7	3.8639E+7	3.8639E+7
Wind	7.2013E+5	7.2013E+5	7.2013E+5	7.2013E+5	7.2013E+5
IGCC1_ NT	0	0	0	0	0
IGCC2_ NT	0	0	0	0	0
IGCC3_ NT	0	0	0	0	0
NGCC1_ NT	0	0	0	3.5741E+6	3.5741E+6
NGCC2_ NT	4.1698E+6	4.1698E+6	4.1698E+6	0	4.1698E+6
NGCC3_ NT	5.2122E+6	5.2122E+6	5.1918E+6	5.1829E+6	5.1444E+6
IGCCc1_ NT	0	0	0	0	0
IGCCc2_ NT	0	0	0	0	0
IGCCc3_ NT	0	0	0	0	4.5718E+6
NGCCc1_ NT	0	0	0	0	3.2911E+6
NGCCc2_ NT	0	0	0	0	3.5890E+6
NGCCc3_ NT	0	0	0	4.1698E+6	4.1698E+6
Solar1_NT	0	0	0	0	0
Solar2_NT	0	0	0	0	1.8615E+5
Wind1_NT	1.0950E+6	1.0950E+6	1.0950E+6	1.0950E+6	1.0950E+6
Wind2_NT	1.3140E+6	1.3140E+6	1.3140E+6	1.3140E+6	1.3140E+6

Table B.14 Electricity Generation Distribution for Various Types of Power Stations vs. Various CO_2 Emission Constraints with 20% Growth in Base Load Demand and with *New Technologies*

Power Stations	0% CO_2 Reduction (MWh)	6% CO_2 Reduction (MWh)	20% CO_2 Reduction (MWh)	40% CO_2 Reduction (MWh)	60% CO_2 Reduction (MWh)
Lambton	1.0122E+7	1.0122E+7	1.0122E+7	7.1773E+6	6.5494E+6
Nanticoke	2.2378E+7	2.2378E+7	2.2378E+7	2.2378E+7	1.0320E+7
Atitokan	8.3123E+5	8.3123E+5	8.3123E+5	8.3123E+5	0
Lakeview	2.4707E+6	2.4462E+6	2.4788E+6	0	0
Lennox	1.8746E+6	1.8746E+6	1.8746E+6	1.8746E+6	1.8746E+6
Thunder Bay	1.5049E+6	1.5049E+6	1.5049E+6	1.5049E+6	0
Nuclear	4.2319E+7	4.2319E+7	4.2319E+7	4.2319E+7	4.2319E+7
Hydro	3.8639E+7	3.8639E+7	3.8639E+7	3.8639E+7	3.8639E+7
Wind	7.2013E+5	7.2013E+5	7.2013E+5	7.2013E+5	7.2013E+5
IGCC1_ NT	0	0	0	0	0
IGCC2_ NT	0	0	0	0	0
IGCC3_ NT	0	0	0	0	0
NGCC1_ NT	3.5741E+6	3.5741E+6	3.5741E+6	3.5741E+6	3.5741E+6
NGCC2_ NT	4.1698E+6	4.1698E+6	4.1698E+6	4.1698E+6	4.1698E+6
NGCC3_ NT	5.2122E+6	5.2122E+6	5.2122E+6	3.9138E+6	4.5085E+6
IGCCc1_ NT	0	0	0	0	0
IGCCc2_ NT	0	0	0	4.1325E+6	4.1325E+6
IGCCc3_ NT	0	0	0	0	4.5718E+6
NGCCc1_ NT	0	0	0	3.2911E+6	3.2911E+6
NGCCc2_ NT	0	0	0	3.5890E+6	3.5890E+6
NGCCc3_ NT	0	0	0	4.1698E+6	4.1698E+6
Solar1_NT	0	0	0	0	0
Solar2_NT	0	0	0	0	0
Wind1_NT	1.0950E+6	1.0950E+6	1.0950E+6	1.0950E+6	1.0950E+6
Wind2_NT	1.3140E+6	1.3140E+6	1.3140E+6	1.3140E+6	1.3140E+6

Table B.15 Electricity Generation Distribution for Various Types of Power Stations vs. Various Aggregated Growth Demands with 10% Fuel Price Increase and 6% CO_2 Reduction with *New Technologies*

Power Stations	Base Load (MWh)	1% Growth (MWh)	5% Growth (MWh)	10% Growth (MWh)	20% Growth (MWh)
Lambton	1.0122E+7	1.0122E+7	1.0122E+7	1.0122E+7	1.0122E+7
Nanticoke	2.2378E+7	2.2378E+7	2.2378E+7	2.2378E+7	2.2378E+7
Atitokan	8.3123E+5	8.3123E+5	8.3123E+5	8.0404E+5	8.3123E+5
Lakeview	2.1751E+6	2.0805E+6	2.4382E+6	2.4796E+6	2.4796E+6
Lennox	1.8883E+6	1.8746E+6	1.8746E+6	1.8778E+6	1.9309E+6
Thunder Bay	1.5049E+6	1.5049E+6	1.5049E+6	1.5049E+6	1.5049E+6
Nuclear	4.2319E+7	4.2319E+7	4.2319E+7	4.2319E+7	4.2319E+7
Hydro	3.8639E+7	3.8639E+7	3.8639E+7	3.8639E+7	3.8639E+7
Wind	7.2013E+5	7.2013E+5	7.2013E+5	7.2013E+5	7.2013E+5
IGCC1_ NT	0	0	0	0	0
IGCC2_ NT	0	0	0	0	0
IGCC3_ NT	0	0	0	0	0
NGCC1_ NT	0	0	3.3704E+6	0	3.5741E+6
NGCC2_ NT	0	0	0	4.1698E+6	4.1698E+6
NGCC3_ NT	0	0	0	5.2122E+6	5.2122E+6
IGCCc1_ NT	0	0	0	0	0
IGCCc2_ NT	0	0	0	0	0
IGCCc3_ NT	0	0	0	0	0
NGCCc1_ NT	0	0	0	0	0
NGCCc2_ NT	0	0	0	0	0
NGCCc3_ NT	0	0	0	0	0
Solar1_NT	0	0	0	0	0
Solar2_NT	0	0	0	0	0
Wind1_NT	0	0	1.0950E+6	1.0950E+6	1.0950E+6
Wind2_NT	0	1.3140E+6	1.3140E+6	1.3140E+6	1.3140E+6

Table B.16 Electricity Generation Distribution for Various Types of Power Stations vs. Various Aggregated Growth Demands with 50% Fuel Price Increase and 6% CO_2 Reduction with *New Technologies*

Power Stations	Base Load (MWh)	1% Growth (MWh)	5% Growth (MWh)	10% Growth (MWh)	20% Growth (MWh)
Lambton	1.0122E+7	1.0122E+7	1.0122E+7	1.0122E+7	1.0122E+7
Nanticoke	2.2378E+7	2.2378E+7	2.2378E+7	2.2378E+7	2.2378E+7
Atitokan	8.3123E+5	8.3123E+5	8.3123E+5	8.3123E+5	8.3123E+5
Lakeview	2.1751E+6	2.0805E+6	2.4796E+6	2.4796E+6	2.4757E+6
Lennox	1.8883E+6	1.8746E+6	2.7546E+6	2.7896E+6	2.7896E+6
Thunder Bay	1.5049E+6	1.5049E+6	1.5049E+6	1.5049E+6	1.5049E+6
Nuclear	4.2319E+7	4.2319E+7	4.2319E+7	4.2319E+7	4.2319E+7
Hydro	3.8639E+7	3.8639E+7	3.8639E+7	3.8639E+7	3.8639E+7
Wind	7.2013E+5	7.2013E+5	7.2013E+5	7.2013E+5	7.2013E+5
IGCC1_ NT	0	0	0	0	0
IGCC2_ NT	0	0	0	0	0
IGCC3_ NT	0	0	0	0	5.7185E+6
NGCC1_ NT	0	0	2.4491E+6	3.5741E+6	3.5741E+6
NGCC2_ NT	0	0	0	0	4.1698E+6
NGCC3_ NT	0	0	0	4.8688E+6	5.2122E+6
IGCCc1_ NT	0	0	0	0	0
IGCCc2_ NT	0	0	0	0	0
IGCCc3_ NT	0	0	0	0	0
NGCCc1_ NT	0	0	0	0	0
NGCCc2_ NT	0	0	0	0	0
NGCCc3_ NT	0	0	0	0	0
Solar1_NT	0	0	0	0	0
Solar2_NT	0	0	0	0	0
Wind1_NT	0	0	1.0950E+6	1.0950E+6	1.0950E+6
Wind2_NT	0	1.3140E+6	1.3140E+6	1.3140E+6	1.3140E+6

Table B.17 Electricity Generation Distribution for Various Types of Power Stations vs. Various Aggregated Growth Demands with 100% Fuel Price Increase and 6% CO_2 Reduction with *New Technologies*

Power Stations	Base Load (MWh)	1% Growth (MWh)	5% Growth (MWh)	10% Growth (MWh)	20% Growth (MWh)
Lambton	1.0122E+7	1.0122E+7	1.0122E+7	1.0122E+7	1.0122E+7
Nanticoke	2.2378E+7	2.2378E+7	2.2378E+7	2.2378E+7	2.2378E+7
Atitokan	8.3123E+5	8.3123E+5	8.3123E+5	8.3123E+5	8.3123E+5
Lakeview	2.1751E+6	2.0805E+6	2.4796E+6	2.4796E+6	2.4796E+6
Lennox	1.8883E+6	1.8746E+6	2.5234E+6	2.6768E+6	2.7896E+6
Thunder Bay	1.5049E+6	1.5049E+6	1.5049E+6	1.5049E+6	1.5049E+6
Nuclear	4.2319E+7	4.2319E+7	4.2319E+7	4.2319E+7	4.2319E+7
Hydro	3.8639E+7	3.8639E+7	3.8639E+7	3.8639E+7	3.8639E+7
Wind	7.2013E+5	7.2013E+5	7.2013E+5	7.2013E+5	7.2013E+5
IGCC1_ NT	0	0	0	0	0
IGCC2_ NT	0	0	0	0	4.7654E+6
IGCC3_ NT	0	0	0	5.7185E+6	5.7185E+6
NGCC1_ NT	0	0	0	0	3.1773E+6
NGCC2_ NT	0	0	0	0	0
NGCC3_ NT	0	0	0	0	0
IGCCc1_ NT	0	0	0	0	0
IGCCc2_ NT	0	0	0	0	0
IGCCc3_ NT	0	0	0	0	0
NGCCc1_ NT	0	0	0	0	0
NGCCc2_ NT	0	0	0	0	0
NGCCc3_ NT	0	0	0	0	0
Solar1_NT	0	0	0	0	0
Solar2_NT	0	0	0	0	0
Wind1_NT	0	0	1.0950E+6	1.0950E+6	1.0950E+6
Wind2_NT	0	1.3140E+6	1.3140E+6	1.3140E+6	1.3140E+6

B.3 Stochastic Model – without *New Technologies*

Table B.18 Electricity Generation Distribution for Various Types of Power Stations vs. Weighting Factor λ with Penalty C^+ = 40; C^- = 400 & 6% CO_2 Reduction without *New Technologies*

Power Stations	λ=0 (MWh)	λ=0.1 (MWh)	λ=0.5 (MWh)	λ=0.6 (MWh)	λ=1 (MWh)
Lambton	1.1214E+7	1.1214E+7	1.1214E+7	1.1214E+7	9.6066E+6
Nanticoke	3.4339E+7	3.4339E+7	3.4339E+7	3.4339E+7	3.4339E+7
Atitokan	1.8834E+6	1.8834E+6	1.8834E+6	1.8834E+6	1.8834E+6
Lakeview	5.8525E+5	5.8525E+5	5.8525E+5	5.8525E+5	0
Lennox	1.8746E+6	1.8746E+6	1.8746E+6	1.8746E+6	1.8746E+6
Thunder Bay	0	0	0	0	0
Nuclear	4.1900E+7	4.1900E+7	4.1900E+7	4.1900E+7	4.1900E+7
Hydro	3.8256E+7	3.8256E+7	3.8256E+7	3.8256E+7	3.8256E+7
Wind	7.1300E+5	7.1300E+5	7.1300E+5	7.1300E+5	7.1300E+5
Coal11_new	0	0	0	0	0
Coal12_new	0	0	0	0	0
Coal13_new	0	0	0	0	0
Coal14_new	0	0	0	0	0
Coal21_new	0	0	0	0	0
Coal22_new	0	0	0	0	0
Coal23_new	0	0	0	0	0
Coal24_new	0	0	0	0	0
NGCC11_new	0	0	0	0	0
NGCC12_new	0	0	0	0	0
NGCC13_new	0	0	0	0	0
NGCC14_ new	0	0	0	0	0
NGCC21_ new	0	0	0	0	0
NGCC22_ new	0	0	0	0	0
NGCC23_ new	0	0	0	0	0
NGCC24_ new	0	0	0	0	0
NGCC31_ new	0	0	0	0	0
NGCC32_ new	0	0	0	0	0
NGCC33_ new	0	0	0	0	0
NGCC34_ new	0	0	0	0	0

Table B.19 Total Cost of Electricity& Financial Risk Cost vs. Weighting Factor *λ* with Penalty $C^+ = 40$; $C^- = 400$ and Fuel Price Increase by 10% and 6% CO_2 Reduction without *New Technologies*

λ	*TotCost* ($/year)	*FixCost* ($/year)	*ExpC* ($/year)	*CVaR* ($/year)
0	4.0051E+9	2.2022E+9	1.8029E+9	7.0810E+9
0.1	4.0151E+9	2.1834E+9	1.8317E+9	6.8834E+9
0.5	4.4049E+9	1.9211E+9	2.4838E+9	5.0457E+9
0.6	4.4049E+9	1.9211E+9	2.4838E+9	5.0457E+9
1	4.4049E+9	1.9211E+9	2.4838E+9	5.0457E+9
∞	4.4250E+9	1.9492E+9	2.4758E+9	5.0440E+9

Table B.20 Electricity Generation Distribution vs. Weighting Factor *λ* for Various Types of Power Stations with Penalty $C^+ = 40$; $C^- = 400$ and Fuel Price Increase by 10% and 6% CO_2 Reduction without *New Technologies*

λ	Fossil Fuel (MWh)	Nuclear (MWh)	Renewable (MWh)	Coal-new (MWh)	NGCC - new (MWh)
0	3.7699E+7	4.1900E+7	3.8969E+7	0	0
0.1	3.5979E+7	4.1900E+7	3.8969E+7	0	2.5952E+6
0.5	1.5026E+7	4.1900E+7	3.8969E+7	0	3.2274E+7
0.6	1.5026E+7	4.1900E+7	3.8969E+7	0	3.2274E+7
1	1.5026E+7	4.1900E+7	3.8969E+7	0	3.2274E+7
∞	1.5101E+7	4.1900E+7	3.8969E+7	0	3.2274E+7

Table B.21 Detailed Electricity Generation Distribution vs. Weighting Factor *λ* for Various Types of Power Stations with Penalty $C^+ = 40$; $C^- = 400$ and Fuel Price Increase by 10% and 6% CO_2 Reduction without *New Technologies*

Power Stations	λ=0 (MWh)	λ=0.1 (MWh)	λ=0.5 (MWh)	λ=0.6 (MWh)	λ=1 (MWh)
Lambton	8.6460E+6	8.6460E+6	8.6460E+6	8.6460E+6	0
Nanticoke	2.7179E+7	2.5458E+7	4.5056E+6	4.5056E+6	1.3226E+7
Atitokan	0	0	0	0	0
Lakeview	0	0	0	0	0
Lennox	1.8746E+6	1.8746E+6	1.8746E+6	1.8746E+6	1.8746E+6
Thunder Bay	0	0	0	0	0
Nuclear	4.1900E+7	4.1900E+7	4.1900E+7	4.1900E+7	4.1900E+7
Hydro	3.8256E+7	3.8256E+7	3.8256E+7	3.8256E+7	3.8256E+7
Wind	7.1300E+5	7.1300E+5	7.1300E+5	7.1300E+5	7.1300E+5
NGCC	0	2.5952E+6	3.2274E+7	3.2274E+7	3.2274E+7

Table B.22 Total Cost of Electricity& Financial Risk Cost vs. Weighting Factor *λ* with Penalty C^+ = 40; C^- = 400 and Fuel Price Increase by 50% and 6% CO_2 Reduction without *New Technologies*

λ	*TotCost* ($/year)	*FixCost* ($/year)	*ExpC* ($/year)	*CVaR* ($/year)
0	4.0051E+9	2.2022E+9	1.8029E+9	7.0810E+9
0.1	4.0051E+9	2.2022E+9	1.8029E+9	7.0810E+9
0.5	4.0577E+9	2.1834E+9	1.8743E+9	6.9368E+9
0.6	4.2775E+9	2.1298E+9	2.1477E+9	6.5071E+9
1	4.6233E+9	1.9806E+9	2.6427E+9	5.9683E+9
∞	4.9513E+9	1.9492E+9	3.0021E+9	5.7019E+9

Table B.23 Electricity Generation Distribution vs. Weighting Factor *λ* for Various Types of Power Stations with Penalty C^+ = 40; C^- = 400 and Fuel Price Increase by 50% and 6% CO_2 Reduction without *New Technologies*

λ	Fossil Fuel (MWh)	Nuclear (MWh)	Renewable (MWh)	Coal-new (MWh)	NGCC-new (MWh)
0	3.7699E+7	4.1900E+7	3.8969E+7	0	0
0.1	3.7699E+7	4.1900E+7	3.8969E+7	0	0
0.5	3.5979E+7	4.1900E+7	3.8969E+7	0	2.5952E+6
0.6	3.0816E+7	4.1900E+7	3.8969E+7	0	1.0381E+7
1	2.1170E+7	4.1900E+7	3.8969E+7	0	2.3705E+7
∞	1.5101E+7	4.1900E+7	3.8969E+7	0	3.2274E+7

Table B.24 Detailed Electricity Generation Distribution vs. Weighting Factor *λ* for Various Types of Power Stations with Penalty C^+ = 40; C^- = 400 and Fuel Price Increase by 50% and 6% CO_2 Reduction without *New Technologies*

Power Stations	λ=0 (MWh)	λ=0.1 (MWh)	λ=0.5 (MWh)	λ=0.6 (MWh)	λ=1 (MWh)
Lambton	8.6460E+6	8.6460E+6	8.6460E+6	8.6460E+6	8.6460E+6
Nanticoke	2.7179E+7	2.7179E+7	2.5458E+7	2.0296E+7	1.0649E+7
Atitokan	0	0	0	0	0
Lakeview	0	0	0	0	0
Lennox	1.8746E+6	1.8746E+6	1.8746E+6	1.8746E+6	1.8746E+6
Thunder Bay	0	0	0	0	0
Nuclear	4.1900E+7	4.1900E+7	4.1900E+7	4.1900E+7	4.1900E+7
Hydro	3.8256E+7	3.8256E+7	3.8256E+7	3.8256E+7	3.8256E+7
Wind	7.1300E+5	7.1300E+5	7.1300E+5	7.1300E+5	7.1300E+5
NGCC	0	0	2.5952E+6	1.0381E+7	2.3705E+7

Table 6.25 Total Cost of Electricity& Financial Risk Cost vs. Weighting Factor *λ* with Penalty $C^+ = 40$; $C^- = 400$ and Fuel Price Increase by 100% and 6% CO_2 Reduction without *New Technologies*

λ	*TotCost* ($/year)	*FixCost* ($/year)	*ExpC* ($/year)	*CVaR* ($/year)
0	4.0051E+9	2.2022E+9	1.8029E+9	7.0810E+9
0.1	4.0051E+9	2.2022E+9	1.8029E+9	7.0810E+9
0.5	4.0051E+9	2.2022E+9	1.8029E+9	7.0810E+9
0.6	4.0051E+9	2.2022E+9	1.8029E+9	7.0810E+9
1	4.0051E+9	2.2022E+9	1.8029E+9	7.0810E+9
∞	5.6091E+9	1.9492E+9	3.6599E+9	6.5242E+9

Table 6.26 Electricity Generation Distribution vs. Weighting Factor *λ* for Various Types of Power Stations with Penalty $C^+ = 40$; $C^- = 400$ and Fuel Price Increase by 100% and 6% CO_2 Reduction without *New Technologies*

λ	Fossil Fuel (MWh)	Nuclear (MWh)	Renewable (MWh)	Coal-new (MWh)	NGCC-new (MWh)
0	3.7699E+7	4.1900E+7	3.8969E+7	0	0
0.1	3.7699E+7	4.1900E+7	3.8969E+7	0	0
0.5	3.7699E+7	4.1900E+7	3.8969E+7	0	0
0.6	3.7699E+7	4.1900E+7	3.8969E+7	0	0
1	3.7699E+7	4.1900E+7	3.8969E+7	0	0
∞	1.5101E+7	4.1900E+7	3.8969E+7	0	3.2274E+7

Table B.27 Electricity Generation Distribution vs. Weighting Factor *λ* for Various Types of Power Stations with Penalty $C^+ = 40$; $C^- = 400$ and Fuel Price Increase by 100% and 6% CO_2 Reduction without *New Technologies*

Power Stations	λ=0 (MWh)	λ=0.1 (MWh)	λ=0.5 (MWh)	λ=0.6 (MWh)	λ=1 (MWh)
Lambton	8.6460E+6	8.6460E+6	8.6460E+6	8.6460E+6	8.6460E+6
Nanticoke	2.7179E+7	2.7179E+7	2.7179E+7	2.7179E+7	2.7179E+7
Atitokan	0	0	0	0	0
Lakeview	0	0	0	0	0
Lennox	1.8746E+6	1.8746E+6	1.8746E+6	1.8746E+6	1.8746E+6
Thunder Bay	0	0	0	0	0
Nuclear	4.1900E+7	4.1900E+7	4.1900E+7	4.1900E+7	4.1900E+7
Hydro	3.8256E+7	3.8256E+7	3.8256E+7	3.8256E+7	3.8256E+7
Wind	7.1300E+5	7.1300E+5	7.1300E+5	7.1300E+5	7.1300E+5
NGCC	0	0	0	0	0

Table B.28 Total Cost of Electricity & Financial Risk Cost vs. Weighting Factor *λ* with Penalty C^+ = 40, C^- = 400 at 20% CO_2 Reduction without *New Technologies*

λ	***TotCost*** **($/year)**	***FixC*** **($/year)**	***ExpC*** **($/year)**	***CVaR*** **($/year)**
0	3.0395E+9	1.0468E+9	1.9927E+9	3.5218E+9
0.1	3.0395E+9	1.0468E+9	1.9927E+9	3.5218E+9
0.5	3.0395E+9	1.0468E+9	1.9927E+9	3.5218E+9
0.6	3.0395E+9	1.0468E+9	1.9927E+9	3.5218E+9
1	3.1706E+9	1.0447E+9	2.1259E+9	3.3314E+9
∞	3.1706E+9	1.0447E+9	2.1259E+9	3.3314E+9

Table B.29 Electricity Generation Distribution vs. Weighting Factor *λ* for Various Types of Power Stations with Penalty C^+ = 40, C^- = 400 at 20% CO_2 Reduction without *New Technologies*

λ	Fossil Fuel (MWh)	Nuclear (MWh)	Renewable (MWh)	Coal-new (MWh)	NGCC-new (MWh)
0	4.9896E+7	4.1900E+7	8.0869E+7	0	0
0.1	4.9896E+7	4.1900E+7	8.0869E+7	0	0
0.5	4.9896E+7	4.1900E+7	8.0869E+7	0	0
0.6	4.9896E+7	4.1900E+7	8.0869E+7	0	0
1	4.7704E+7	4.1900E+7	8.0869E+7	0	0
∞	4.7704E+7	4.1900E+7	8.0869E+7	0	0

B.4 Stochastic Model – with *New Technologies*

Table B.30 Total Cost of Electricity& Financial Risk Cost vs. Weighting Factor *λ* with 6% CO_2 Reduction and Penalty C^+ = 20; C^- = 200 with *New Technologies*

λ	*TotCost* ($/year)	*FixCost* ($/year)	*ExpC* ($/year)	*CVaR* ($/year)
0	2.6617E+9	2.4205E+9	2.4121E+8	2.9028E+9
0.1	2.6627E+9	2.4046E+9	2.5807E+8	2.8807E+9
1	2.6782E+9	2.3201E+9	3.5813E+8	2.7586E+9
1.4	2.6782E+9	2.3201E+9	3.5813E+8	2.7586E+9
10	2.6782E+9	2.3201E+9	3.5813E+8	2.7586E+9
∞	2.6782E+9	2.3201E+9	3.5813E+8	2.7586E+9

Table B.31 Electricity Generation Distribution vs. Weighting Factor *λ* for Various Types of Power Stations with Penalty C^+ = 20; C^- = 200 at 6% CO_2 Reduction with *New Technologies*

λ	Fossil Fuel (MWh)	Nuclear (MWh)	Renewable (MWh)	IGCC-NT (MWh)	IGCCc-NT (MWh)	NGCC-NT (MWh)	NGCCc-NT (MWh)
0	5.0457E+7	4.1900E+7	3.8969E+7	0	0	0	0
0.1	5.0141E+7	4.1900E+7	3.8969E+7	0	0	0	0
1	4.8264E+7	4.1900E+7	3.8969E+7	0	0	0	0
1.4	4.8264E+7	4.1900E+7	3.8969E+7	0	0	0	0
10	4.8264E+7	4.1900E+7	3.8969E+7	0	0	0	0
∞	4.8264E+7	4.1900E+7	3.8969E+7	0	0	0	0

Table B.32 Detailed Electricity Generation Distribution vs. Weighting Factor *λ* for Various Types of Power Stations with Penalty $C^+ = 20$; $C^- = 200$ at 6% CO_2 Reduction with *New Technologies*

Power Stations	λ=0 (MWh)	λ=0.1 (MWh)	λ=1 (MWh)	λ=1.4 (MWh)	λ=10 (MWh)
Lambton	8.6460E+6	9.3280E+6	8.6460E+6	8.6460E+6	8.6460E+6
Nanticoke	3.4339E+7	3.4339E+7	3.3632E+7	3.3632E+7	3.3632E+7
Atitokan	1.8834E+6	1.8834E+6	1.8834E+6	1.8834E+6	1.8834E+6
Lakeview	9.9813E+5	0	0	0	0
Lennox	1.8746E+6	1.8746E+6	1.8746E+6	1.8746E+6	1.8746E+6
ThunderBay	2.7156E+6	2.7156E+6	2.2281E+6	2.2281E+6	2.2281E+6
Nuclear	4.1900E+7	4.1900E+7	4.1900E+7	4.1900E+7	4.1900E+7
Hydro	3.8256E+7	3.8256E+7	3.8256E+7	3.8256E+7	3.8256E+7
Wind	7.1300E+5	7.1300E+5	7.1300E+5	7.1300E+5	7.1300E+5
IGCC1_ NT	0	0	0	0	0
IGCC2_ NT	0	0	0	0	0
IGCC3_ NT	0	0	0	0	0
NGCC1_NT	0	0	0	0	0
NGCC2_NT	0	0	0	0	0
NGCC3_NT	0	0	0	0	0
IGCCc1_NT	0	0	0	0	0
IGCCc2_NT	0	0	0	0	0
IGCCc3_NT	0	0	0	0	0
NGCCc1_NT	0	0	0	0	0
NGCCc2_NT	0	0	0	0	0
NGCCc3_NT	0	0	0	0	0
Solar1_NT	0	0	0	0	0
Solar2_NT	0	0	0	0	0
Wind1_NT	0	0	0	0	0
Wind2_NT	1.3140E+6	1.3140E+6	1.3140E+6	1.3140E+6	1.3140E+6

Table B.33 Total Cost of Electricity& Financial Risk Cost vs. Weighting Factor *λ* with 6% CO_2 Reduction and Penalty $C^+ = 40$; $C^- = 400$ with *New Technologies*

λ	*TotCost* ($/year)	*FixCost* ($/year)	*ExpC* ($/year)	*CVaR* ($/year)
0	2.9029E+9	2.4205E+9	4.8241E+8	3.3852E+9
0.1	2.9029E+9	2.4205E+9	4.8241E+8	3.3852E+9
1	3.0364E+9	2.3201E+9	7.1625E+8	3.1971E+9
1.4	3.0364E+9	2.3201E+9	7.1625E+8	3.1971E+9
10	3.0364E+9	2.3201E+9	7.1625E+8	3.1971E+9
∞	2.9029E+9	2.4205E+9	7.1625E+8	3.1971E+9

Table B.34 Electricity Generation Distribution vs. Weighting Factor *λ* for Various Types of Power Stations with Penalty C^+ = 40; C^- = 400 at 6% CO_2 Reduction with *New Technologies*

λ	Fossil Fuel (MWh)	Nuclear (MWh)	Renewable (MWh)	IGCC-NT (MWh)	IGCCc-NT (MWh)	NGCC-NT (MWh)	NGCCc-NT (MWh)
0	5.0457E+7	4.1900E+7	3.8969E+7	0	0	0	0
0.1	5.0457E+7	4.1900E+7	3.8969E+7	0	0	0	0
1	4.8264E+7	4.1900E+7	3.8969E+7	0	0	0	0
1.4	4.8264E+7	4.1900E+7	3.8969E+7	0	0	0	0
10	4.8264E+7	4.1900E+7	3.8969E+7	0	0	0	0
∞	4.8264E+7	4.1900E+7	3.8969E+7	0	0	0	0

Table B.35 Detailed Electricity Generation Distribution vs. Weighting Factor *λ* for Various Types of Power Stations with Penalty C^+ = 40; C^- = 400 at 6% CO_2 Reduction with *New Technologies*

Power Stations	λ=0 (MWh)	λ=0.1 (MWh)	λ=1 (MWh)	λ=1.4 (MWh)	λ=10 (MWh)
Lambton	8.6460E+6	8.6460E+6	8.6460E+6	8.6460E+6	8.6460E+6
Nanticoke	3.4339E+7	3.4339E+7	3.3632E+7	3.3632E+7	3.3632E+7
Atitokan	1.8834E+6	1.8834E+6	1.8834E+6	1.8834E+6	1.8834E+6
Lakeview	9.9813E+5	9.9813E+5	0	0	0
Lennox	1.8746E+6	1.8746E+6	1.8746E+6	1.8746E+6	1.8746E+6
ThunderBay	2.7156E+6	2.7156E+6	2.2281E+6	2.2281E+6	2.2281E+6
Nuclear	4.1900E+7	4.1900E+7	4.1900E+7	4.1900E+7	4.1900E+7
Hydro	3.8256E+7	3.8256E+7	3.8256E+7	3.8256E+7	3.8256E+7
Wind	7.1300E+5	7.1300E+5	7.1300E+5	7.1300E+5	7.1300E+5
IGCC1_ NT	0	0	0	0	0
IGCC2_ NT	0	0	0	0	0
IGCC3_ NT	0	0	0	0	0
NGCC1_NT	0	0	0	0	0
NGCC2_NT	0	0	0	0	0
NGCC3_NT	0	0	0	0	0
IGCCc1_NT	0	0	0	0	0
IGCCc2_NT	0	0	0	0	0
IGCCc3_NT	0	0	0	0	0
NGCCc1_NT	0	0	0	0	0
NGCCc2_NT	0	0	0	0	0
NGCCc3_NT	0	0	0	0	0
Solar1_NT	0	0	0	0	0
Solar2_NT	0	0	0	0	0
Wind1_NT	0	0	0	0	0
Wind2_NT	1.3140E+6	1.3140E+6	1.3140E+6	1.3140E+6	1.3140E+6

Table B.36 Total Cost of Electricity& Financial Risk Cost vs. Weighting Factor *λ* with Penalty $C^+ = 40$; $C^- = 400$ and Fuel Price Increase by 10% and 6% CO_2 Reduction with *New Technologies*

λ	*TotCost* ($/year)	*FixCost* ($/year)	*ExpC* ($/year)	*CVaR* ($/year)
0	3.5684E+9	2.4878E+9	1.0805E+9	4.1872E+9
0.1	3.5684E+9	2.4878E+9	1.0805E+9	4.1872E+9
1	3.6377E+9	2.5012E+9	1.1366E+9	3.8948E+9
1.4	3.6377E+9	2.5012E+9	1.1366E+9	3.8948E+9
10	3.6377E+9	2.5012E+9	1.1366E+9	3.8948E+9
∞	3.6377E+9	2.5012E+9	1.1366E+9	3.8948E+9

Table B.37 Electricity Generation Distribution vs. Weighting Factor *λ* for Various Types of Power Stations with Penalty $C^+ = 40$; $C^- = 400$ and Fuel Price Increase by 10% and 6% CO_2 Reduction with *New Technologies*

λ	Fossil Fuel (MWh)	Nuclear (MWh)	Renewable (MWh)	IGCC-NT (MWh)	IGCCc-NT (MWh)	NGCC-NT (MWh)	NGCCc-NT (MWh)
0	3.8021E+7	4.1900E+7	3.8969E+7	0	0	3.5741E+6	7.7587E+6
0.1	3.8021E+7	4.1900E+7	3.8969E+7	0	0	3.5741E+6	7.7587E+6
1	3.9308E+7	4.1900E+7	3.8969E+7	0	0	0	7.6755E+6
1.4	3.9308E+7	4.1900E+7	3.8969E+7	0	0	0	7.6755E+6
10	3.9308E+7	4.1900E+7	3.8969E+7	0	0	0	7.6755E+6
∞	3.9308E+7	4.1900E+7	3.8969E+7	0	0	0	7.6755E+6

Table B.38 Detailed Electricity Generation Distribution vs. Weighting Factor *λ* for Various Types of Power Stations with Penalty $C^+ = 40$; $C^- = 400$ and Fuel Price Increase by 10% and 6% CO_2 Reduction with *New Technologies*

Power Stations	λ=0 (MWh)	λ=0.1 (MWh)	λ=1 (MWh)	λ=1.4 (MWh)	λ=10 (MWh)
Lambton	8.6460E+6	8.6460E+6	8.6460E+6	8.6460E+6	8.6460E+6
Nanticoke	2.7500E+7	2.7500E+7	2.7500E+7	2.8787E+7	2.8787E+7
Atitokan	0	0	0	0	0
Lakeview	0	0	0	0	0
Lennox	1.8746E+6	1.8746E+6	1.8746E+6	1.8746E+6	1.8746E+6
ThunderBay	0	0	0	0	0
Nuclear	4.1900E+7	4.1900E+7	4.1900E+7	4.1900E+7	4.1900E+7
Hydro	3.8256E+7	3.8256E+7	3.8256E+7	3.8256E+7	3.8256E+7
Wind	7.1300E+5	7.1300E+5	7.1300E+5	7.1300E+5	7.1300E+5
IGCC1_ NT	0	0	0	0	0
IGCC2_ NT	0	0	0	0	0
IGCC3_ NT	0	0	0	0	0
NGCC1_NT	3.5741E+6	3.5741E+6	0	0	0
NGCC2_NT	0	0	0	0	0
NGCC3_NT	0	0	0	0	0
IGCCc1_NT	0	0	0	0	0
IGCCc2_NT	0	0	0	0	0
IGCCc3_NT	0	0	0	0	0
NGCCc1_NT	0	0	0	0	0
NGCCc2_NT	3.5890E+6	3.5890E+6	3.5890E+6	3.5890E+6	3.5890E+6
NGCCc3_NT	4.1698E+6	4.1698E+6	4.0865E+6	4.0865E+6	4.0865E+6
Solar1_NT	0	0	0	0	0
Solar2_NT	0	0	1.8615E+5	1.8615E+5	1.8615E+5
Wind1_NT	1.0950E+6	1.0950E+6	1.0950E+6	1.0950E+6	1.0950E+6
Wind2_NT	1.3140E+6	1.3140E+6	1.3140E+6	1.3140E+6	1.3140E+6

Table B.39 Total Cost of Electricity& Financial Risk Cost vs. Weighting Factor *λ* with Penalty $C^+ = 40$; $C^- = 400$ and Fuel Price Increase by 50% and 6% CO_2 Reduction with *New Technologies*

λ	*TotCost* ($/year)	*FixCost* ($/year)	*ExpC* ($/year)	*CVaR* ($/year)
0	3.7688E+9	2.4878E+9	1.2809E+9	4.4377E+9
0.1	3.7755E+9	2.5010E+9	1.2745E+9	4.0803E+9
1	3.7874E+9	2.5843E+9	1.2031E+9	4.0560E+9
1.4	3.7874E+9	2.5843E+9	1.2031E+9	4.0560E+9
10	3.8108E+9	2.7036E+9	1.1071E+9	4.0427E+9
∞	3.8108E+9	2.7036E+9	1.1071E+9	4.0427E+9

Table B.40 Electricity Generation Distribution vs. Weighting Factor *λ* for Various Types of Power Stations with Penalty C^+ = 40; C^- = 400 and Fuel Price Increase by 50% and 6% CO_2 Reduction with *New Technologies*

λ	Fossil Fuel (MWh)	Nuclear (MWh)	Renewable (MWh)	IGCC-NT (MWh)	IGCCc-NT (MWh)	NGCC-NT (MWh)	NGCCc-NT (MWh)
0	3.8021E+7	4.1900E+7	3.8969E+7	0	0	3.5741E+6	7.7587E+6
0.1	3.9302E+7	4.1900E+7	3.8969E+7	0	0	0	7.7587E+6
1	3.8944E+7	4.1900E+7	3.8969E+7	0	4.1325E+6	0	4.1698E+6
1.4	3.8944E+7	4.1900E+7	3.8969E+7	0	4.1325E+6	0	4.1698E+6
10	3.8512E+7	4.1900E+7	3.8969E+7	0	8.6579E+6	0	0
∞	3.8512E+7	4.1900E+7	3.8969E+7	0	8.6579E+6	0	0

Table B.41 Detailed Electricity Generation Distribution vs. Weighting Factor *λ* for Various Types of Power Stations with Penalty C^+ = 40; C^- = 400 and Fuel Price Increase by 50% and 6% CO_2 Reduction with *New Technologies*

Power Stations	λ=0 (MWh)	λ=0.1 (MWh)	λ=1 (MWh)	λ=1.4 (MWh)	λ=10 (MWh)
Lambton	8.6460E+6	8.6460E+6	8.6460E+6	8.6460E+6	8.6460E+6
Nanticoke	2.7500E+7	2.8781E+7	2.8424E+7	2.8424E+7	2.7991E+7
Atitokan	0	0	0	0	0
Lakeview	0	0	0	0	0
Lennox	1.8746E+6	1.8746E+6	1.8746E+6	1.8746E+6	1.8746E+6
ThunderBay	0	0	0	0	0
Nuclear	4.1900E+7	4.1900E+7	4.1900E+7	4.1900E+7	4.1900E+7
Hydro	3.8256E+7	3.8256E+7	3.8256E+7	3.8256E+7	3.8256E+7
Wind	7.1300E+5	7.1300E+5	7.1300E+5	7.1300E+5	7.1300E+5
IGCC1_ NT	0	0	0	0	0
IGCC2_ NT	0	0	0	0	0
IGCC3_ NT	0	0	0	0	0
NGCC1_NT	3.5741E+6	0	0	0	0
NGCC2_NT	0	0	0	0	0
NGCC3_NT	0	0	0	0	0
IGCCc1_NT	0	0	0	0	0
IGCCc2_NT	0	0	4.1325E+6	4.1325E+6	4.0860E+6
IGCCc3_NT	0	0	0	0	4.5718E+6
NGCCc1_NT	0	0	0	0	0
NGCCc2_NT	3.5890E+6	3.5890E+6	0	0	0
NGCCc3_NT	4.1698E+6	4.1698E+6	4.1698E+6	4.1698E+6	4.1698E+6
Solar1_NT	0	0	0	0	0
Solar2_NT	0	1.8615E+5	0	0	0
Wind1_NT	1.0950E+6	1.0950E+6	1.0950E+6	1.0950E+6	1.0950E+6
Wind2_NT	1.3140E+6	1.3140E+6	1.3140E+6	1.3140E+6	1.3140E+6

Table B.42 Total Cost of Electricity& Financial Risk Cost vs. Weighting Factor *λ* with Penalty C^+ = 40; C^- = 400 and Fuel Price Increase by 100% and 6% CO_2 Reduction with *New Technologies*

λ	***TotCost*** **($/year)**	***FixCost*** **($/year)**	***ExpC*** **($/year)**	***CVaR*** **($/year)**
0	3.8272E+9	2.3209E+9	1.5063E+9	6.1611E+9
0.1	3.9039E+9	2.7035E+9	1.2004E+9	4.1660E+9
1	3.9057E+9	2.7036E+9	1.2021E+9	4.1614E+9
1.4	3.9057E+9	2.7036E+9	1.2021E+9	4.1614E+9
10	3.9057E+9	2.7036E+9	1.2021E+9	4.1614E+9
∞	3.9057E+9	2.7036E+9	1.2021E+9	4.1614E+9

Table B.43 Electricity Generation Distribution vs. Weighting Factor *λ* for Various Types of Power Stations with Penalty C^+ = 40; C^- = 400 and Fuel Price Increase by 100% and 6% CO_2 Reduction with *New Technologies*

λ	Fossil Fuel (MWh)	Nuclear (MWh)	Renewable (MWh)	IGCC-NT (MWh)	IGCCc-NT (MWh)	NGCC-NT (MWh)	NGCCc-NT (MWh)
0	3.9762E+7	4.1900E+7	3.8969E+7	0	0	0	0
0.1	3.8506E+7	4.1900E+7	3.8969E+7	0	8.7044E+6	0	0
1	3.8512E+7	4.1900E+7	3.8969E+7	0	8.6579E+6	0	0
1.4	3.8512E+7	4.1900E+7	3.8969E+7	0	8.6579E+6	0	0
10	3.8512E+7	4.1900E+7	3.8969E+7	0	8.6579E+6	0	0
∞	3.8512E+7	4.1900E+7	3.8969E+7	0	8.6579E+6	0	0

Table B.44 Detailed Electricity Generation Distribution vs. Weighting Factor *λ* for Various Types of Power Stations with Penalty C^+ = 40; C^- = 400 and Fuel Price Increase by 100% and 6% CO_2 Reduction with *New Technologies*

Power Stations	λ=0 (MWh)	λ=0.1 (MWh)	λ=1 (MWh)	λ=1.4 (MWh)	λ=10 (MWh)
Lambton	8.6460E+6	8.6460E+6	8.6460E+6	8.6460E+6	8.6460E+6
Nanticoke	2.9241E+7	2.7985E+7	2.7991E+7	2.7991E+7	2.7991E+7
Atitokan	0	0	0	0	0
Lakeview	0	0	0	0	0
Lennox	1.8746E+6	1.8746E+6	1.8746E+6	1.8746E+6	1.8746E+6
ThunderBay	0	0	0	0	0
Nuclear	4.1900E+7	4.1900E+7	4.1900E+7	4.1900E+7	4.1900E+7
Hydro	3.8256E+7	3.8256E+7	3.8256E+7	3.8256E+7	3.8256E+7
Wind	7.1300E+5	7.1300E+5	7.1300E+5	7.1300E+5	7.1300E+5
IGCC1_ NT	0	0	0	0	0
IGCC2_ NT	0	0	0	0	0
IGCC3_ NT	0	0	0	0	0
NGCC1_NT	0	0	0	0	0
NGCC2_NT	0	0	0	0	0
NGCC3_NT	0	0	0	0	0
IGCCc1_NT	0	0	0	0	0
IGCCc2_NT	0	4.1325E+6	4.0860E+6	4.0860E+6	4.0860E+6
IGCCc3_NT	0	4.5718E+6	4.5718E+6	4.5718E+6	4.5718E+6
NGCCc1_NT	0	0	0	0	0
NGCCc2_NT	0	0	0	0	0
NGCCc3_NT	0	0	0	0	0
Solar1_NT	0	0	0	0	0
Solar2_NT	0	0	0	0	0
Wind1_NT	1.0950E+6	1.0950E+6	1.0950E+6	1.0950E+6	1.0950E+6
Wind2_NT	1.3140E+6	1.3140E+6	1.3140E+6	1.3140E+6	1.3140E+6

Table B.45 Total Cost of Electricity& Financial Risk Cost vs. Weighting Factor *λ* with 20% CO_2 Reduction and Penalty C^+ = 40; C^- = 400 with *New Technologies*

λ	*TotCost* ($/year)	*FixC* ($/year)	*ExpC* ($/year)	*CVaR* ($/year)
0	3.0369E+9	2.5545E+9	4.8241E+8	3.5192E+9
0.1	3.0369E+9	2.5545E+9	4.8241E+8	3.5192E+9
1	3.1689E+9	2.4526E+9	7.1625E+8	3.3296E+9
1.4	3.1689E+9	2.4526E+9	7.1625E+8	3.3296E+9
10	3.1689E+9	2.4526E+9	7.1625E+8	3.3296E+9
∞	3.1689E+9	2.4526E+9	7.1625E+8	3.3296E+9

Table B.46 Electricity Generation Distribution vs. Weighting Factor λ for Various Types of Power Stations with Penalty $C^+ = 40$; $C^- = 400$ and 20% CO_2 Reduction with *New Technologies*

λ	Fossil Fuel (MWh)	Nuclear (MWh)	Renewable (MWh)	IGCC-NT (MWh)	IGCCc-NT (MWh)	NGCC-NT (MWh)	NGCCc-NT (MWh)
0	5.0457E+7	4.1900E+7	3.8969E+7	0	0	0	0
0.1	5.0457E+7	4.1900E+7	3.8969E+7	0	0	0	0
1	4.9578E+7	4.1900E+7	3.8969E+7	0	0	0	0
1.4	4.9578E+7	4.1900E+7	3.8969E+7	0	0	0	0
10	4.9578E+7	4.1900E+7	3.8969E+7	0	0	0	0
∞	4.9578E+7	4.1900E+7	3.8969E+7	0	0	0	0

Appendix C

Benefits of Financial Risk Management

There are many benefits of managing financial risk. The key benefit is the achievement of company objectives. Other benefits are better focus, strengthening of the planning process, and having the means to help management identify opportunities. The benefits to the management process include: a cultural change that supports open discussion about risks and potentially risk information; improved financial and operational management by ensuring that risks are adequately considered in the decision-making process; and increased accountability of management.

C.1 Net-Present Value

The net-present value model is used to generate a number or an approximate value for each project to allow comparison between projects. It does not tell how much each project is worth because the model predicts the future. It is therefore the best tool for comparison of projects, which makes it a deal for security risk management, because that is all we want to do:

- Analyze many competing ideas
- Create a value for ideas
- Compare those values against each other
- Select the ones with the highest value

C.2 Financial Risk Management (FRM)

In broader terms, financial risk management is defined as uncertain future events that could expose the firm to the chance of loss. Here, loss is a relative concept. It needs a reference level to be defined. The reference level is the list of objectives stated in the business plan of the firms. Consequently, risk can be defined as uncertain events that could influence the achievement of the firms' strategic, operational, and financial objectives. Jorion (2001) used risk as the volatility of unexpected outcomes.

Financial risk management is process, which provides assurance that:

- Objectives are more likely to be achieved
- Benefits will be or are more likely to be achieved

- Losses will not happen or are not likely to happen

The aim of FRM is not to eliminate risk, but rather to manage opportunities and minimize adverse effects. It is a process to identify risks and impacts of these risks and then provides a method for addressing these impacts to reduce threats.

The FRM process involves:

- The identification of finance risks
- The measurement and assessment of these risks from a current exposure perspective
- The determination of a target or desired level of exposure

C.3 Benefits of Financial Risk Management

The benefits of FRM approach are:

- The ability to deliver improved performance
- The improved probability of the achievement of objectives
- The ability to demonstrate enhanced stakeholder value
- The ability to improve confidence level

Other benefits are:

- Supporting strategies and business planning
- Support effective use of resources
- Promoting continuous improvement
- Fewer shocks and unwelcome surprises

C.4 Financial Risk Management in the Framework of Two-Stage Stochastic Programming

The main objective of FRM is a mathematical formulation for problem dealing with planning and design under uncertainty that allows management of financial risk according to the decision maker's preference. A new step toward this objective is a formal probabilistic definition of financial risk (Bagajewicz, 2004) is adopted to be used and its relation to downside risk is analyzed using these definitions. Two-stage programming models are introduced to manage financial risk.

This kind of optimization problem is characterized by two essential features:

- Uncertainty in the problem data
- Sequence of decisions

Some of the model parameters are considered random variables with a certain probability distribution. In turn, some decisions are taken at the beginning stage, that is, before the uncertainty is revealed, whereas a number of other decisions can be made only after the uncertain data become known. The first class of decision is called the first stage decision, and the period when these decisions are taken is referred to as the first stage. On the other hand, the decisions made after the uncertainty is unveiled are called second stage or recourse decisions, and the corresponding period is called the second stage.

The first stage decisions are structured and most of the time related to capital investment at the beginning of the project, whereas, the second-stage decisions are often operational.

Conditional value ate risk, CVaR, a measurement of financial risk, is introduced to describe risk. CVaR is a risk measure and is expected value of the costs in the five percent worst cases to be minimized. Risk is presented because the two stage stochastic models do not take into account the variability of the second stage cost except for its expected value. Therefore, the concept of downside risk to measure the recourse cost variability and obtain solutions is appealing to a risk adverse investor.

Appendix D

Parameters Used in Model

1. Capital Cost

Parameter	Value ($/MW)
Capital cost for new plants without capture	
Capital cost for new PC	
PC11	1,578,000
PC12	1,578,000
PC13	1,578,000
PC14	1,578,000
PC21	1,413,000
PC22	1,413,000
PC23	1,413,000
PC24	1,413,000
Capital cost for new NGCC	
NGCC11	617,000
NGCC12	617,000
NGCC13	617,000
NGCC14	617,000
NGCC21	552,000
NGCC22	552,000
NGCC23	552,000
NGCC24	552,000
NGCC31	442,000
NGCC32	442,000
NGCC33	442,000
NGCC34	442,000
Capital cost for new plants with capture	
Capital cost for new PC with capture	
PCcap11	2,613,000
PCcap12	2,613,000
PCcap13	2,613,000
PCcap14	2,613,000
PCcap21	2,468,000
PCcap22	2,468,000
PCcap23	2,468,000
PCcap24	2,468,000
PCcap31	2,271,000

PCcap32	2,271,000
PCcap33	2,271,000
PCcap34	2,271,000
Capital cost for new NGCC with capture	
NGcap11	1,437,000
NGcap12	1,437,000
NGcap13	1,437,000
NGcap14	1,437,000
NGcap21	1,207,000
NGcap22	1,207,000
NGcap23	1,207,000
NGcap24	1,207,000
Capital cost of *new technologies*	
Solar1	4,100,000
Solar2	3,981,000
Wind1	1,250,000
Wind2	1,167,000
IG1	2,175,000
IG2	1,813,000
IG3	1,722,000
NG1	620,000
NG2	554,000
NG3	443,000
IC1	2,610,000
IC2	2,390,000
IC3	2,239,000
NC1	1,364,000
NC2	1,172,000
NC3	1,050,000

2. Operating Cost

Parameter		Value ($/MWh)
Operating cost for renewable energy		
Operating cost for nuclear		21.33
Operating cost for hydroelectric		3.33
Operating cost for wind		2.67
Operating cost for existing fossil station		
Lambton operating cost		
	Coal	Ng
L1	23	32.1
L2	23	32.1
L3	17	26.1

L4	17	26.1
Nanticoke operating cost		
N1	20	29.1
N2	20	29.1
N3	20	29.1
N4	20	29.1
N5	20	29.1
N6	20	29.1
N7	20	29.1
N8	20	29.1
Atitokan operating cost		
A1	20	29.1
Lakeview operating cost		
LV1	23.33	32.43
LV2	23.33	32.43
LV3	23.33	32.43
LV4	23.33	32.43
LV5	23.33	32.43
LV6	23.33	32.43
LV7	23.33	32.43
LV8	23.33	32.43
Lennox operating cost		
LN1	46.67	46.67
LN2	46.67	46.67
LN3	46.67	46.67
LN4	46.67	46.67
Thunder Bay operating cost		
TB1	20	29.1
TB1	20	29.1
Operating cost for new power plants without capture		
Operating cost for new PC		
PC11		2.53
PC12		2.53
PC13		2.53
PC14		2.53
PC21		2.47
PC22		2.47
PC23		2.47
PC24		2.47
Operating cost for new NGCC		
NGCC11		8.1

NGCC12	8.1
NGCC13	8.1
NGCC14	8.1
NGCC21	9.37
NGCC22	9.37
NGCC23	9.37
NGCC24	9.37
NGCC31	8.3
NGCC32	8.3
NGCC33	8.3
NGCC34	8.3
Operating cost for new power plants with capture	
Operating cost for new PC with capture	
PCcap11	18.03
PCcap12	18.03
PCcap13	18.03
PCcap14	18.03
PCcap21	18.06
PCcap22	18.06
PCcap23	18.06
PCcap24	18.06
PCcap31	18.16
PCcap32	18.16
PCcap33	18.16
PCcap34	18.16
Operating cost for new NGCC with capture	
NGcap11	9.68
NGcap12	9.68
NGcap13	9.68
NGcap14	9.68
NGcap21	5.3
NGcap22	5.3
NGcap23	5.3
NGcap24	5.3
Operating cost of *new technologies*	
Solar1	50
Solar2	30
Wind1	7.5
Wind2	5
IG1	13.3
IG2	10.6
IG3	9

NG1	3
NG2	3.1
NG3	3.3
IC1	16.6
IC2	13.3
IC3	11.3
NC1	5.6
NC2	4.6
NC3	4.5

3. CO_2 Emissions

Parameter		**Value (tonnes/MWh)**
CO_2 emissions in tonne per year		37,338,013
CO_2 emissions from existing fossil station		
CO_2 emissions from Lambton		
	Coal	Natural Gas
L1	0.9386	0.5631
L2	0.9386	0.5631
L3	0.9384	0.5628
L4	0.9384	0.5628
CO_2 emissions from Nanticoke		
N1	0.93	0.558
N2	0.93	0.558
N3	0.93	0.558
N4	0.93	0.558
N5	0.93	0.558
N6	0.93	0.558
N7	0.93	0.558
N8	0.93	0.558
CO_2 emissions from Atitokan		
A1	1.023	0.6138
CO_2 emissions from Lakeview		
LV1	0.9765	0.5859
LV2	0.9765	0.5859
LV3	0.9765	0.5859
LV4	0.9765	0.5859
LV5	0.9765	0.5859
LV6	0.9765	0.5859
LV7	0.9765	0.5859
LV8	0.9765	0.5859
CO_2 emissions from Lennox		
LN1	0.651	0.651
LN2	0.651	0.651
LN3	0.651	0.651

LN4	0.651	0.651
CO_2 emissions from Thunder Bay		
TB1	1.023	0.6138
TB2	1.023	0.6138
CO_2 emissions from new power plants without capture		
CO_2 emissions from new PC		
PC11		0.8333
PC12		0.8333
PC13		0.8333
PC14		0.8333
PC21		0.89
PC22		0.89
PC23		0.89
PC24		0.89
CO_2 emissions from new NGCC		
NGCC11		0.4
NGCC12		0.4
NGCC13		0.4
NGCC14		0.4
NGCC21		0.37
NGCC22		0.37
NGCC23		0.37
NGCC24		0.37
NGCC31		0.404
NGCC32		0.404
NGCC33		0.404
NGCC34		0.404
CO_2 emissions from new power plants with capture		
CO_2 emissions from new PC with capture		
PCcap11		0.1112
PCcap12		0.1112
PCcap13		0.1112
PCcap14		0.1112
PCcap21		0.119
PCcap22		0.119
PCcap23		0.119
PCcap24		0.119
PCcap31		0.118
PCcap32		0.118
PCcap33		0.118
PCcap34		0.118
CO_2 emissions from new NGCC with capture		
NGcap11		0.048
NGcap12		0.048

NGcap13	0.048
NGcap14	0.048
NGcap21	0.0495
NGcap22	0.0495
NGcap23	0.0495
NGcap24	0.0495
CO_2 emmissions for *new technology* without capture	
IGCC1	0.4
IGCC2	0.45
IGCC3	0.5
NGCC1	0.2
NGCC2	0.22
NGCC3	0.25
CO_2 emmissions for *new technology* with capture	
IGCC1	0.04
IGCC2	0.07
IGCC3	0.09
NGCC1	0.02
NGCC2	0.025
NGCC3	0.04

4. Plant Capacity

Parameter	**Value (MWh/year)**
Maximum electricity generation for existing power stations	
Lambton net electricity generation	
L1	4,323,020
L2	4,323,020
L3	4,323,020
L4	4,323,020
Nanticoke net electricity generation	
N1	4,292,400
N2	4,292,400
N3	4,292,400
N4	4,292,400
N5	4,292,400
N6	4,292,400
N7	4,292,400
N8	4,292,400
Atitoken net electricity generation	
A1	1,883,400
Lakeview net electricity generation	
LV1	1,246,110
LV2	1,246,110
LV3	1,246,110

LV4	1,246,110
LV5	1,246,110
LV6	1,246,110
LV7	1,246,110
LV8	1,246,110
Lennox net electricity generation	
LN1	4,686,600
LN2	4,686,600
LN3	4,686,600
LN4	4,686,600
Thunder Bay net electricity generation	
TB1	1,357,800
TB2	1,357,800
Installed capacity (MW) for new candidate power plants without capture	
PC11	4,012,080
PC12	4,012,080
PC13	4,012,080
PC14	4,012,080
PC21	4,590,240
PC22	4,590,240
PC23	4,590,240
PC24	4,590,240
NGCC11	2,856,636
NGCC12	2,856,636
NGCC13	2,856,636
NGCC14	2,856,636
NGCC21	3,460,200
NGCC22	3,460,200
NGCC23	3,460,200
NGCC24	3,460,200
NGCC31	4,441,320
NGCC32	4,441,320
NGCC33	4,441,320
NGCC34	4,441,320
Installed capacity (MW) for new candidate power plants with capture	
PCcap11	2,987,160
PCcap12	2,987,160
PCcap13	2,987,160
PCcap14	2,987,160
PCcap21	4,012,080
PCcap22	4,012,080
PCcap23	4,012,080
PCcap24	4,012,080
PCcap31	4,309,920
PCcap31	4,309,920

PCcap31	4,309,920
PCcap31	4,309,920
NGcap11	3,784,320
NGcap12	3,784,320
NGcap13	3,784,320
NGcap14	3,784,320
NGcap21	6,570,000
NGcap22	6,570,000
NGcap23	6,570,000
NGcap24	6,570,000
Actual electricity generation for existing power plants for NomE	
Lambton actual electricity generation	
L1	1,768,705
L2	1,768,705
L3	3,242,295
L4	3,242,295
Nanticoke actual electricity generation	
N1	3,219,300
N2	3,219,300
N3	2,619,567
N4	2,619,567
N5	2,619,567
N6	2,619,567
N7	2,619,567
N8	2,619,567
Atitokan actual electricity generation	
A1	823,000
Lakeview actual electricity generation	
LV1	306,875
LV2	306,875
LV3	306,875
LV4	306,875
LV5	306,875
LV6	306,875
LV7	306,875
LV8	306,875
Lennox actual electricity generation	
LN1	690,500
LN2	690,500
LN3	690,500
LN4	690,500
Thunder Bay actual electricity generation	
TB1	745,000
TB2	745,000
Nuclear actual electricity generation	

Pick-A	0
Pick-B	14,300,000
Darling	27,600,000
Hydroelectric actual electricity generation	
NW-Cari	347,328
NW-Car	88,128
NW-Mani	373,248
NW-White	352,512
NW-Silv	248,832
NW-Kaba	129,600
NW-Came	414,720
NW-Pine	720,576
NW-Alex	347,328
NW-Aqua	243,648
NW-Aub	851,472
NW-WElls	1,256,184
NW-Ray	241,776
NW-Red	215,496
NE-Kip	741,096
NE-Harm	741,096
NE-Otter	956,592
NE-Smok	273,312
NE-Long	699,048
NE-Abi	1,629,360
NE-Sturg	26,280
NE-Sandy	15,768
NE-Wawai	57,816
NE-Ind	15,768
NE-Hound	21,024
NE-Notch	1,440,144
NE-Mata	52,560
O-Huld	1,277,208
O-Joa	2,254,824
O-Chen	756,864
O-Cala	26,280
O-Barr	925,056
O-Mount	893,520
O-Stew	956,592
O-Amp	430,992
O-Chats	504,576
O-Saund	5,340,096
N-DeCew	120,888
N-DeCew2	756,864

N-Beck1	2,617,488
N-Beck2	7,384,680
N-Beck3	914,544
E-Mc	15,768
E-Conis	26,280
E-Crys	42,048
E-Nipi	10,512
E-Bing	5,256
E-Elli	10,512
E-Ragg	42,048
E-Eddy	42,048
E-Chute	52,560
E-Hanna	5,256
E-Treth	10,512
E-South	21,024
E-High	15,768
E-Mern	10,512
E-Lake	10,512
E-Heal	63,072
E-Sey	31,536
E-Ran	47,304
E-Aub	10,512
E-Eugen	31,536
E-Sills	10,512
E-Hag	21,024
E-Frank	15,768
E-Sid	21,024
E-Meyer	21,900
Wind actual electricity generation	
Tiverton	713,000

5. Fuel Cost

Parameter	Value ($/GJ)
price of coal	2.2
price of NG	6.1

6. Heat Rate

Parameter	Value (GJ/MWh)
hrPP1	9.12
hrPP2	9.16
hrPI1	7.37
hrPI2	7.9
hrPI3	8.78
hrPN1	7.1
hrPN2	6.74
hrPN3	6.37
hrPC1	12.19
hrPC2	12.17
hrPC3	12.1
hrIC1	10.46
hrIC2	9.97
hrNC1	7.48
hrNC2	7.8

7. Sequestration Cost

Parameter	Value (\$/tonne CO_2 Storage)	
Sequestration cost for existing fossil station		
Sequestration cost for Lambton		
	Erie	Huron
L1	40.64	51.25
L2	40.64	51.25
L3	43.08	53.69
L4	43.08	53.69
Sequestration cost for Nanticoke		
N1	37.43	53.07
N2	37.43	53.07
N3	40.49	56.13
N4	40.49	56.13
N5	40.49	56.13
N6	40.49	56.13
N7	40.49	56.13
N8	40.49	56.13
Sequestration cost for Atikokan		
A1	196.10	163.26
Sequestration cost for Lakeview		
LV1	127.77	136.51
LV2	127.77	136.51
LV3	127.77	136.51
LV4	127.77	136.51
LV5	127.77	136.51
LV6	127.77	136.51

LV7	127.77	136.51
LV8	127.77	136.51
Sequestration cost for Lennox		
LN1	10.5	11.0
LN2	10.5	11.0
LN3	10.5	11.0
LN4	10.5	11.0
Sequestration cost for Thunder Bay		
TB1	221.26	144.02
TB2	221.26	144.02
Sequestration cost for new plants with capture ($/yr)		
Sequestration cost for new PC with capture		
PCcap11	36,554,157	80,054,157
PCcap12	36,554,157	80,054,157
PCcap13	36,554,157	80,054,157
PCcap14	36,554,157	80,054,157
PCcap21	38,272,571	81,772,571
PCcap22	38,272,571	81,772,571
PCcap23	38,272,571	81,772,571
PCcap24	38,272,571	81,772,571
PCcap31	39,168,000	82,668,000
PCcap32	39,168,000	82,668,000
PCcap33	39,168,000	82,668,000
PCcap34	39,168,000	82,668,000
Sequestration cost for new NGCC		
NGcap11	34,034,578	77,534,578
NGcap12	34,034,578	77,534,578
NGcap13	34,034,578	77,534,578
NGcap14	34,034,578	77,534,578
NGcap21	35,176,854	78,676,854
NGcap22	35,176,854	78,676,854
NGcap23	35,176,854	78,676,854
NGcap24	35,176,854	78,676,854

8. Retrofit Cost

Parameter	**Value ($/tonne CO_2 capture)**
Retrofit cost due to capture process on existing fossil stations	
Capture cost from Lambton	
L1	26.62
L2	26.62
L3	29.06
L4	29.06
Capture cost for Nanticoke	
N1	24.02
N2	24.02

N3		27.08
N4		27.08
N5		27.08
N6		27.08
N7		27.08
N8		27.08
Capture Cost for Atikokan		
A1		40.74
Capture Cost for Lakeview		
LV1		64.54
LV2		64.54
LV3		64.54
LV4		64.54
LV5		64.54
LV6		64.54
LV7		64.54
LV8		64.54
Capture Cost for Lennox		
	Erie	Huron
LN1	300	300
LN2	300	300
LN3	300	300
LN4	300	300
Capture cost from Thunder Bay		
TB1		33.79
TB2		33.79
Electricity required for CO_2 capture		
	Coal	Natural Gas
L1	0.317	0.356
L2	0.317	0.356
L3	0.317	0.356
L4	0.317	0.356
N1	0.317	0.356
N2	0.317	0.356
N3	0.317	0.356
N4	0.317	0.356
N5	0.317	0.356
N6	0.317	0.356
N7	0.317	0.356
N8	0.317	0.356
A1	0.317	0.356
LV1	0.317	0.356
LV2	0.317	0.356
LV3	0.317	0.356
LV4	0.317	0.356

LV5	0.317	0.356
LV6	0.317	0.356
LV7	0.317	0.356
LV8	0.317	0.356
LN1	0.356	0.356
LN2	0.356	0.356
LN3	0.356	0.356
LN4	0.356	0.356
TB1	0.317	0.356
TB2	0.317	0.356

9. General

Parameter	Value
Annual operating time	8,760 (hr/year)
ACF	0.75
ACFnuc	0.85
Ammortized factor	0.15
ACF lower bound	0.1
Allowable electricity increment	0.01
Retrofit cost factor due to fuel switching ($M20 per 1000 MW)	20000
Percent CO_2 capture	0.9
Eletricity required for CO_2 capture (MWh per tonne CO_2 capture)	0.317
Sensitivity analysis for capital cost	1.0
Electricity generated at peak time	13764 (MWe)
Maximum energ requirement for capture	1E9 (MWh/yr)
Big number used in CO_2 emission constraints	1E11
Big number used in linearization for CCS retrofit	1E13
Big number used in linearization for new plant with capture	1E13