# A Multi-Period Optimization Model for Energy Planning with $CO_2$ Emission Consideration

by

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A thesis
presented to the University of Waterloo
in fulfillment of the
thesis requirement for the degree of
Master of Applied Science
in
Chemical Engineering

Waterloo, Ontario, Canada, 2007

## Author's Declaration

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.

I understand that my thesis may be made electronically available to the public.

Hamidreza Mirzaesmaeeli

# Abstract

Planning for Ontario's future energy supply mix is a very challenging undertaking which requires consideration of various drivers and decision criteria. From the literature review conducted, no published work has been found addressing the multi-period energy planning problem with $CO_2$ emission constraints and the option of carbon capture and storage (CCS). The objective of this project was to develop a novel multi-period mixed-integer non-linear programming (MINLP) model that is able to realize the optimal mix of energy supply sources which will meet current and future electricity demand, $CO_2$ emission targets, and lower the overall cost of electricity. This model was implemented in GAMS (General Algebraic Modeling System).

The model was formulated using an objective function that minimizes the net present value of the cost of electricity (COE) over a time horizon of 14 years. The formulation incorporates several time dependent parameters such as forecasted energy demand, fuel price variability, construction lead time, conservation initiatives, and increase in fixed operational and maintenance costs over time.

The model was applied to two case studies in order to examine the economical, structural, and environmental effects that would result if Ontario's electricity sector was required to reduce its $CO_2$ emissions to a specific limit. The first case study examined a base case scenario in which no $CO_2$ limits were imposed. The second case study examined a scenario in which Ontario's electricity sector must comply with $CO_2$ emission limits similar to the Kyoto target of 6% below 1990 levels.

The results indicate that in order to meet the $CO_2$ targets of 6% below 1990 levels, Nanticoke, Atikokan, and Thunder Bay coal-fired power plants must be fuel-switched, and Lambton coal-fired power plant must be retrofitted with a CCS system. Furthermore, a total $CO_2$ reduction of approximately 32% was achieved when compared to the base case. The total cost associated with reducing the $CO_2$ emissions to 6% below 1990 levels, per ton of $CO_2$, was $48.79 / ton $CO_2$ reduced. The total expenditure for Case Study II ($CO_2$ limit of 6% below 1990 levels) was approximately 10.1% higher than for the base case.

This model offers many potential benefits to Ontario's energy sector. In addition to providing an optimal solution for meeting future electricity demand, it can help Ontario meet its emissions targets while minimizing the overall cost of electricity. Furthermore, although this project was aimed at Ontario's future energy supply mix, it could also be readily applied to other regions or even countries as a whole.

## Acknowledgements

I would like to gratefully acknowledge my wonderful supervisors, Dr. Ali Elkamel, Dr. Peter L. Douglas, and Dr. Eric Croiset, for their continuous support, encouragement, and invaluable guidance.

My overwhelming thanks go to my friends from the $CO_2$ Capture and Storage System Group. I would specially like to thank Flora Chui, Colin Alie, and Guillermo Ordorica.

Finally, I would like to acknowledge the financial support of CANMET.

## Dedication

*This thesis is dedicated to my wonderful parents, my two amazing brothers, and my beloved Danijela, without whom my life would be empty.*

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## *List of Acronyms*

| | |
|---|---|
| CANDU | CANada Deuterium Uranium |
| CCS | Carbon capture and storage |
| CDM | Conservation and Demand Management |
| $CO_2$ | Carbon dioxide |
| COE | Cost of electricity |
| EIA | Energy Information Administration |
| GAMS | General Algebraic Modeling System |
| GHG | Greenhouse gas |
| IECM | Integrated Environmental Control Model |
| IESO | Independent Electricity System Operator |
| IGCC | Integrated gasification combined cycle |
| LSFCR | Large Scale Fuel Channel Replacement |
| MEA | Monoethanolamine |
| MILP | Mixed-integer linear programming |
| MINLP | Mixed-integer non-linear programming |
| Mt | Megatonnes |
| MW | Megawatts |
| MWh | Megawatt-hour |
| NEB | National Energy Board |
| NG | Natural gas |
| NGCC | Natural gas combined cycle |
| O&M | Operating and maintenance |
| OMI | Ontario-Manitoba interconnection |
| OPA | Ontario Power Authority |
| OPG | Ontario Power Generation |
| PC | Pulverized coal combustion |
| SP | Supply-Push |
| TV | Techno-Vert |
| TWh | Terawatt-hour |

# *Chapter 1*

## *1.1 Ontario's Emerging Energy Challenge*

Currently, Ontario's operable generation capacity equals approximately 30,662 MW from all sources (Ontario Power Authority, 2005). As shown in Figure 1, 37% of total capacity can be attributed to nuclear sources, 26% is renewable, 21% is coal-fired, and the remaining 16% consists of gas and oil fueled sources.

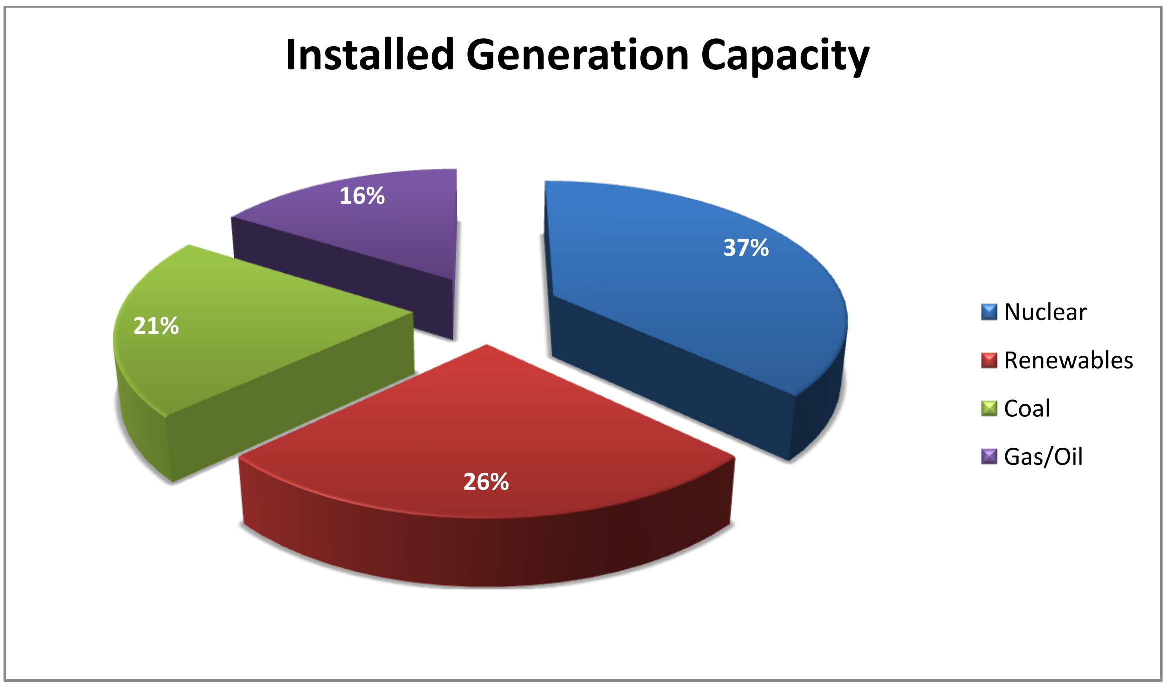



**Figure 1 –** Ontario's current installed generation capacity in terms of percentile (Ontario Power Authority, 2005).

Ontario's electricity sector faces one of the most challenging times in its history. While the demand for electricity has increased due to economic growth and rising population, the electricity sector's capacity has decreased over the past decade (Ontario Power Authority, 2005).

As shown in Figure 2, Ontario's supply capacity is projected to decline over the next two decades with a rapid decline in supply emerging in the next several years. Two major factors contribute to this decline in supply capacity. Firstly, it can be seen that Ontario's coal-fired capacity will be completely removed from the electricity supply mix by 2009. This is mainly due to Ontario's current government legislating the closure of all coal-fired plants within the next few years. Secondly, nuclear capacity declines sharply due to the retirement of many of the existing nuclear units. The combination of these two factors will decrease Ontario's installed capacity by approximately 17,316 MW in the next twenty years.

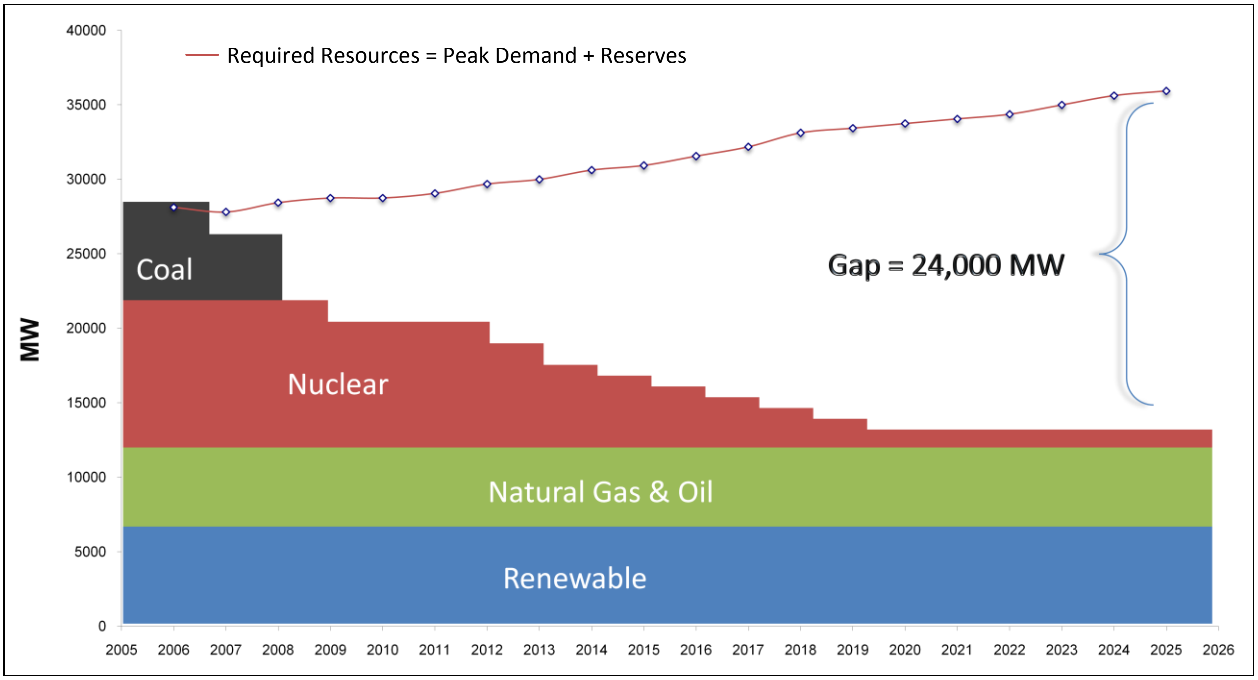



**Figure 2** -Ontario's demand growth and installed generating capacity portfolio over the next 20 years (Ontario Power Authority, 2005).

In the meantime, Ontario's demand increases steadily over the next two decades. If Ontario's current consumption and demand continue, the required resources rise from 27,000 MW in 2006 to approximately 37,000 MW in 2025.

The decline of supply and increase in demand results in a potential energy gap of 24,000 MW by year 2025. A solution must be found to fill this energy gap and meet the long-term capacity needs.

To further complicate Ontario's future supply-demand shortfall problem, greenhouse gas (GHG) emissions must be taken into consideration when evaluating potential solutions. Carbon dioxide ($CO_2$) is suspected to be the principal GHG responsible for global warming and climate change. With a growing concern with global warming and its effects on the environment, the industry is striving to reduce its $CO_2$ emissions.

Ontario Power Generation (OPG), which accounts for 70% of electricity generation in Ontario, has had wavering $CO_2$ emissions over the past few decades. From Figure 3, $CO_2$ emissions from OPG have varied from a high of 37 million tons in 2000 to a low of 15 million tons in 1994. The variability in $CO_2$ emissions from OPG is mainly due to changes in electricity demand and technological improvements. Since 1995, OPG has entered into a voluntary commitment to reduce their GHG emissions to levels equivalent to the 1990 baseline. Though some progress in achieving this target has been made over the past few years, OPG has often had to resort to buying $CO_2$ emission reduction credits to achieve their voluntary targets. As of this time, no long-term sustainable strategy has been established by OPG to address their ongoing $CO_2$ emission challenge.

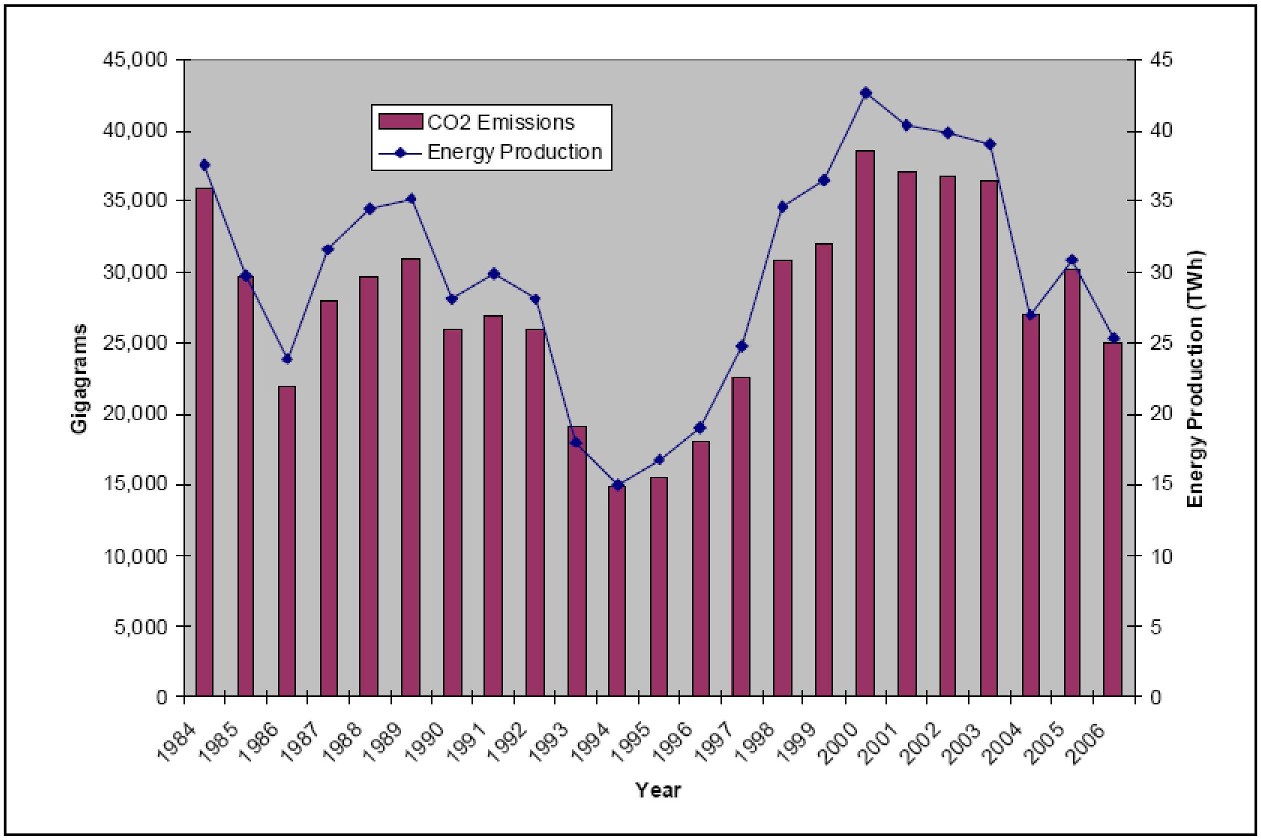



**Figure 3 –** Historical energy production (TWh) and carbon dioxide emissions from OPG (Ontario Power Generation, 2007).

The ratification of the international Kyoto protocol imposes additional pressure for the Canadian government to reduce its $CO_2$ emissions. Under the Kyoto protocol, which was signed by the Canadian government in 1998 and ratified in 2002, the country agreed to reduce GHG emissions by 6% below 1990 levels by 2008-2010.

Although the Kyoto directive is to reduce GHG emissions, there has been an increasing trend in emissions in Canada for the past several years. In 2003, Canada contributed about 740 Megatonnes (Mt) of $CO_2$ equivalent of GHGs to the atmosphere, an increase of about 3% over the recorded emissions from 2002 (Figure 4). This increase in GHG emissions is significantly greater than the 1% increase which occurred between 2001 and 2002. If no mitigating measures are taken, it is estimated that Canada's GHG emissions will rise to 809 Mt by the year 2010 (Environment Canada, 2005).

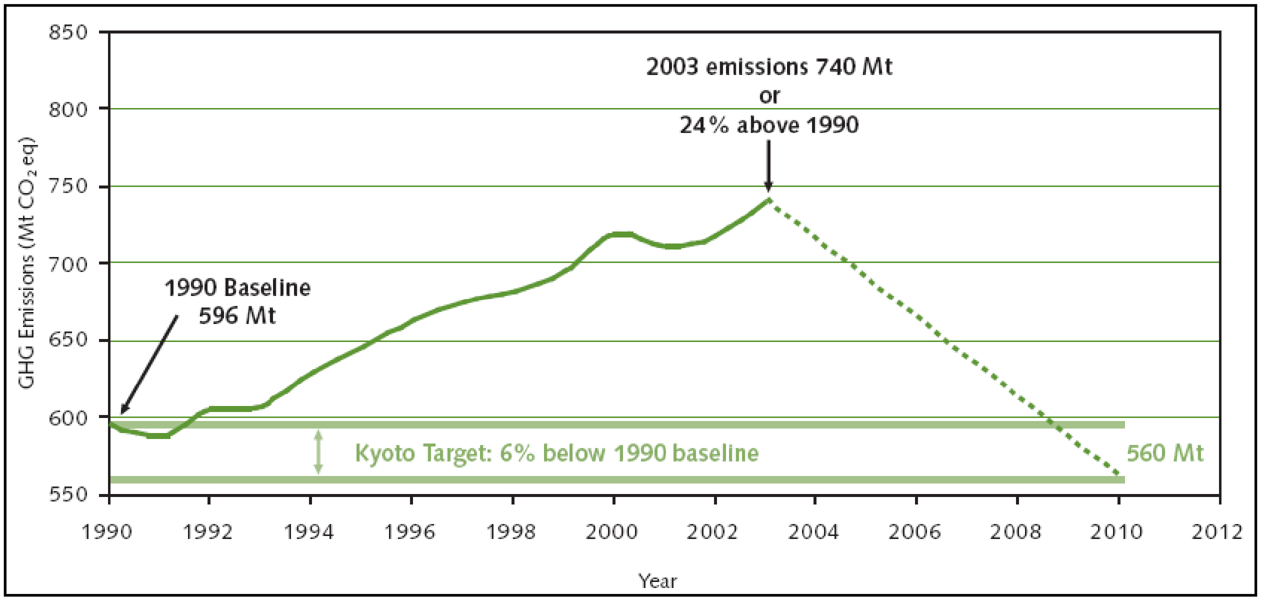



**Figure 4-** Canada's emission trend and Kyoto's emission target (Environment Canada, 2005).

## *1.2 Motivation for the Research*

As discussed in Section 1.1, Ontario is facing a large energy gap due to increasing demand and a decline in installed generating capacity. Furthermore, as environmental regulations become more stringent, there will be an increasing need to reduce the amount of GHGs and other pollutants emitted to the environment. Consideration must be given to meeting the rising energy demand in both an environmentally sound and cost-effective manner. In light of all the issues discussed, Ontario must find a sustainable energy mix in order to realize its future challenges.

There are various supply technologies available that could be used to help meet Ontario's energy demand. These supply options differ based on a few factors, including economical, environmental, and operational characteristics. Some technologies offer lower capital and operating cost at high emission rates, while other supply options have higher associated costs but lower environmental impacts. Furthermore, there are several options available for pollutant mitigation, such as Carbon Capture and Storage (CCS). The underlining question then becomes what mix of supply technologies and pollutant mitigation options should be selected to meet Ontario's energy demand and environmental limits at a minimal cost. This is the question that this thesis aims to answer and its main motivation.

## 1.3 Research Objectives

Planning for Ontario's future energy supply mix is a very challenging undertaking which requires consideration of various drivers and decision criteria. From the literature review conducted, no prior work has been found addressing the problem of finding the optimal strategy for energy planning with $CO_2$ emission constraints and the option to implement CCS. The objective of this thesis is to develop a novel optimization model in order to realize the optimal mix of energy supply sources, with consideration for $CO_2$ emissions.

This project aims to develop a deterministic multi-period mixed-integer non-linear programming (MINLP) model that is able to realize the optimal mix of energy supply sources which will meet current and future electricity demand, $CO_2$ emission targets, and lower the overall cost of electricity. This model is implemented in GAMS (General Algebraic Modeling System).

The model is formulated using an objective function that minimizes the net present value of the cost of electricity (COE) over a time horizon of 14 years. The formulation incorporates several time dependent parameters such as forecasted energy demand, fuel price variability, construction lead time, conservation initiatives, and increase in fixed operational and maintenance costs over time. Although this project is aimed at Ontario's future energy supply mix, it could also be readily applied to other regions or even countries as a whole.

The specific goals and deliverables of this thesis work are as follows:

- To formulate a deterministic multi-period MINLP model that is able to realize the optimal mix of energy supply sources which will meet Ontario's current and future electricity demand, $CO_2$ emission targets, and lower the overall cost of electricity.
- To program and implement the model in GAMS.

- To acquire detailed data on various supply options that can be used as parameters for the model.
- To examine the cost and feasibility of using CCS in Ontario.
- To apply the model to case studies examining the impact of legislative actions that would force Ontario's electricity sector to reduce $CO_2$ emissions to a specific limit. The relative impact is examined based on economical, structural, and environmental affects.

## *1.4 Contribution of the Research*

This model offers many potential benefits to Ontario's energy sector. Firstly, a novel deterministic multi-period MINLP model is developed that can be used to determine an optimal mix of energy sources needed to meet Ontario's current and future energy demand. Such a model is particularly important in light of the energy gap Ontario faces in the future. Furthermore, the research work aims to meet Ontario's $CO_2$ emission targets while minimizing the overall cost of electricity.

The application of the model to case studies will aid in understanding the role of different supply options in Ontario and their impact on overall cost and environment. In recent years, there has been a lot of focus on the use of CCS as a potential $CO_2$ mitigation option. The case studies examined in this thesis will help determine the feasibility of such $CO_2$ mitigation options in Ontario, and when they would be best implemented.

Though the model formulation is complex, the model is implemented in GAMS employing a user-friendly interface that makes it simple for future users to change parameters and implement different case studies. Although this project is aimed at Ontario's future energy supply mix, it could also be readily applied to other regions or even countries as a whole.

## 1.5 Methodology

The methodology of the project can be broken down into 5 main phases. The first phase involves defining the problem statement. The second phase focuses on conducting a thorough literature review on current and past research involving multi-period optimization planning. The third and fourth phase of the project involves gathering data and developing the mathematical model respectively. Finally, the last phase of the project consists of developing possible case studies for the model. Figure 5 outlines and briefly discusses the 5 main phases of the project.

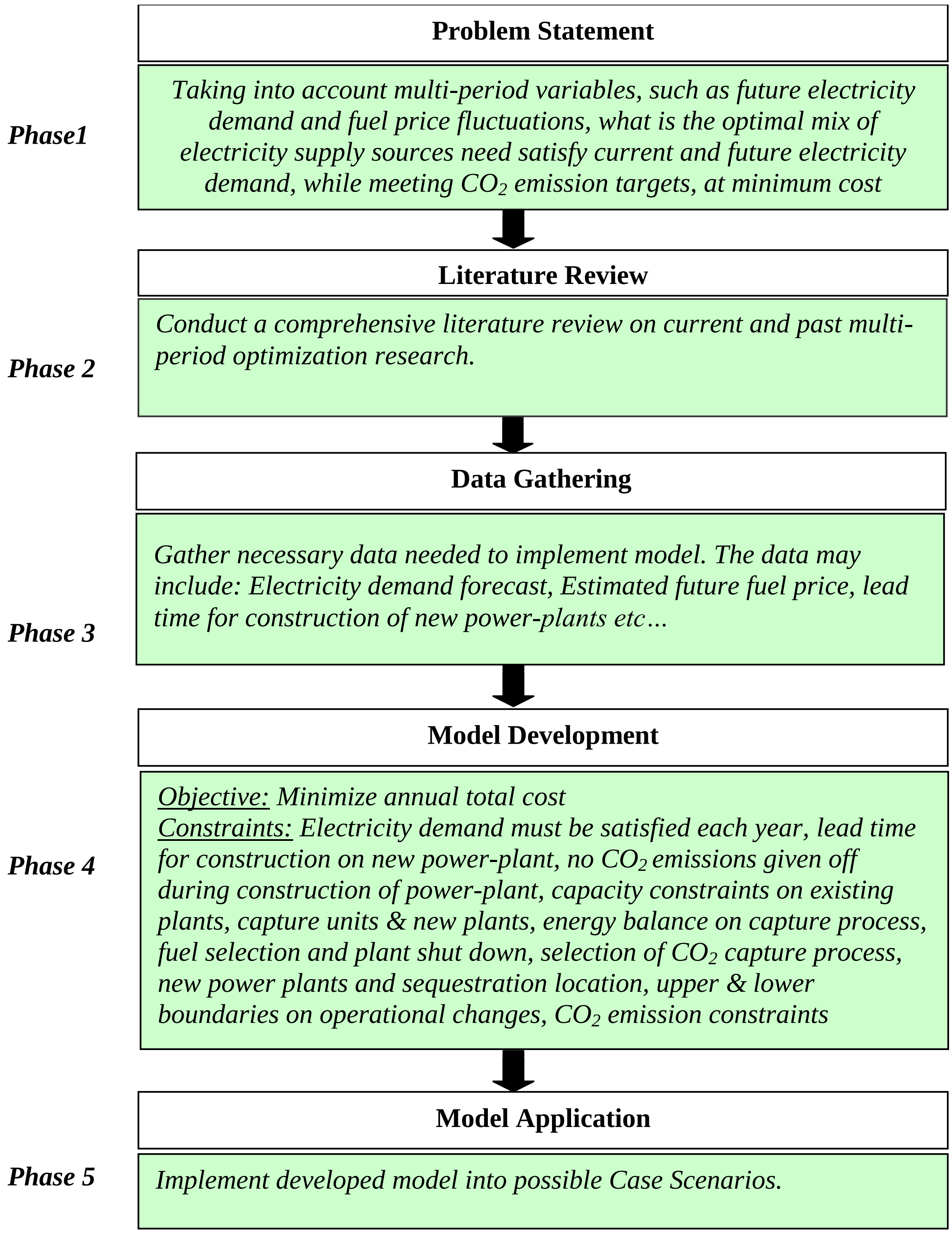



**Figure 5 -** Five phase methodology for thesis completion. The five phases involve: defining the problem statement, conducting a literature review, gathering data, developing the model, and implementation of case studies.

## 1.6 Organization of Thesis

The remainder of this dissertation is organized into four chapters. Chapter 2 provides a detailed background on potential supply technologies and $CO_2$ mitigating options. Moreover, this Chapter gives an overview of Ontario's current energy mix and projected future outlooks. The last section of Chapter 2 provides a journal review on current and past research done in the field of multi-period optimization planning.

Chapter 3 of this thesis presents the mathematical formulation for the deterministic multi-period MINLP model. Furthermore, this chapter presents the GAMS model statistics and provides a discussion in regards to solving the MINLP model.

Chapter 4 details the case studies used to implement the mathematical model developed in the previous chapter. Moreover, it contains data for the different parameters needed in the model and provides a comparative analysis between the case studies.

Finally, Chapter 5 contains the concluding remarks and presents recommendations for future work.

# Chapter 2

## 2.1 Overview

The following sections provide background information for the mathematical formulation and the case studies discussed in the upcoming chapters. The first section describes and provides the technical background for the different supply technologies discussed in this thesis. Section 2.3 describes the methodology behind current Carbon Capture and Storage (CCS) technologies and provides information on potential $CO_2$ sequestration sites in Ontario. The sections that follow outline background information regarding Ontario's current energy mix and projected future outlooks. The last section of this chapter provides a journal review on current and past research done in the field of multi-period optimization planning.

## 2.2 Supply Technologies

### 2.2.1 Nuclear Power Stations

Nuclear power stations produce, contain, and control the energy obtained from splitting of Uranium atoms. Nuclear reactors act like large steam engines. The energy released from electric power plants is used to heat water and produce steam, which then drives the turbine-generators to produce electricity. Just like fossil fuel plants use burning of coal, oil or gas as a heat source, nuclear power stations use heat given off from the splitting of $U_{235}$ atoms for its heat source.

The most common type of nuclear reactors are Pressurized Water Reactors, comprising 59 percent of reactor types used worldwide (Naini, Walden, Pinno, Stogran, & Mutysheva, 2005). These reactors can use either light water or heavy water to control the speed at which the atoms travel and hence increase the amount of energy released from fission of Uranium atoms. An example of a Pressurized Heavy Water Reactor (PHWR) is CANDU (CANada Deuterium Uranium) reactor technology. Figure 6 shows a typical CANDU plant.

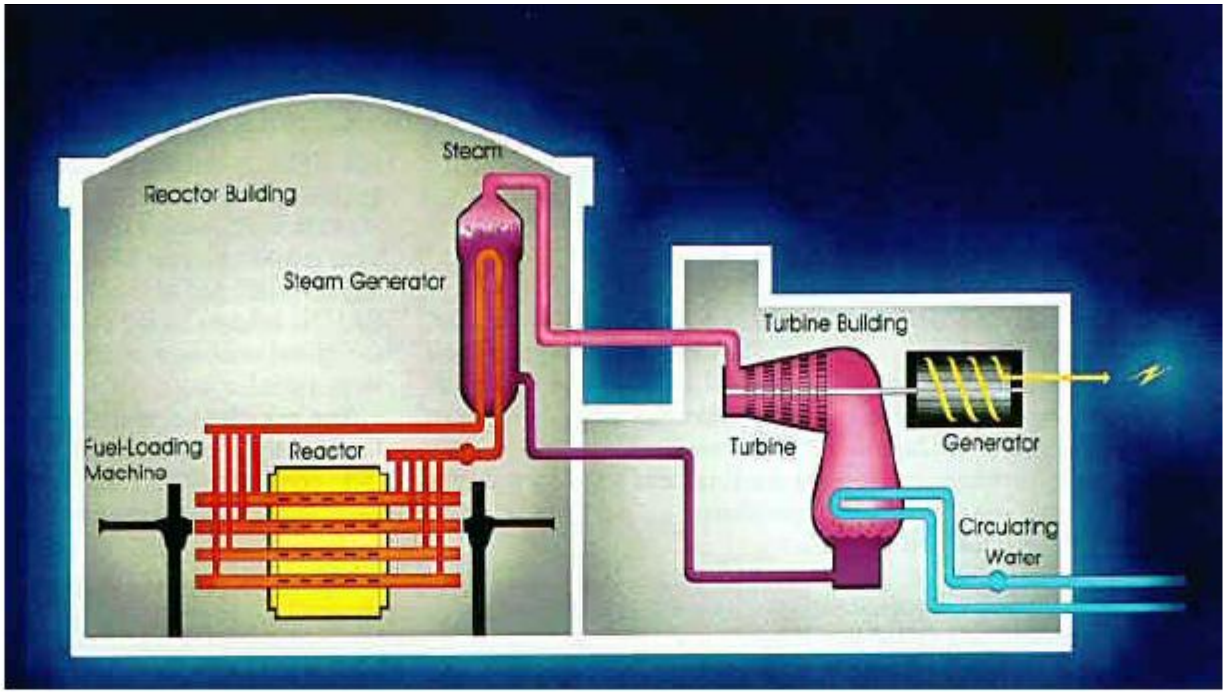



**Figure 6 –** Schematic diagram of typical CANDU 6 nuclear power plant (Naini et al., 2005).

A CANDU plant uses uranium as a fuel source. Uranium atoms are split in the reactor, giving off energy in the form of heat. This heat is then used to boil water in steam generators, producing high pressure steam which is used to turn the blades of a turbine. The turbines turn the electrical generators which produce electricity that is sent to the customers.

### *2.2.2 Natural Gas Power Stations*

Natural gas power stations use natural gas as a source of fuel. There are two types of turbines that can be used to provide power to natural gas power stations for electricity production: steam turbines or gas turbines. Steam turbine systems use high temperature and pressure steam to transfer energy to rotating turbine blades, while gas turbines use gas expansion. The turbines are then used to turn electrical generators for production of electricity.

There are three types of technologies that can be used in natural gas power stations: simple cycle gas turbine, natural gas combined cycle turbine and cogeneration turbine. Each technology is discussed in more detail in the following sections. A fourth type, fuel cells, is also available but will not be discussed here.

#### 2.2.2.1 Simple Cycle Gas Turbine

Simple cycle gas turbines compress air in an air compressor. This compressed air is used to burn natural gas in a combustion chamber. The resulting high temperature combustion gas and air mixture expands in the turbine, driving an electrical generator to produce electricity.

#### 2.2.2.2 Natural Gas Combined Cycle (NGCC)

Natural gas combined cycle (NGCC) power plants produce electricity from a combination of a gas cycle and a steam cycle. The gas cycle is identical to the one described in the simple cycle gas turbine section (refer to Section 2.2.2.1). In addition to the gas cycle, the waste heat of the exhaust gases leaving the gas turbine is used for steam generation in a heat exchanger. The steam generated from the heat exchanger is used to drive a steam generator and produce additional electricity.

#### 2.2.2.3 Cogeneration

Cogeneration is similar to NGCC, and uses exhaust gases leaving the gas cycle as feed to a heat exchanger. However, whereas NGCC uses steam produced from the heat exchanger to drive a steam generator and produce additional electricity, cogeneration uses the thermal energy of the steam directly for purposes such as industrial processes or water heating. Hence, in cogeneration, the steam is not used to produce electricity.

### 2.2.3 Coal Power Stations

Coal power plants use coal as a fuel source for power generation. Technologies used in coal power plants are categorized into two groups: combustion and gasification. Pulverized coal power stations use combustion technologies and are discussed in the following section. An example of gasification technology is an Integrated Gasification Combined Cycle, described in Section 2.2.3.2 below.

#### 2.2.3.1 Pulverized Coal Power Stations

Pulverized coal power stations use coal combustion technologies. Pulverized coal is fed to a steam boiler and steam turbine. A simple schematic of pulverized coal combustion is presented in Figure 7. Coal is first ground to a very fine powder for combustion. The pulverized coal is then combusted in a series of burners, generating hot gases that are used to produce steam in a boiler. The steam is used to turn a turbine which drives a generator and produces electricity. During the process of coal burning, ash is formed in the combustion chamber. The bottom ash consisting of large particles can be collected and removed. The rest of the coal ash remains in the combustion chamber and is known as fly ash. Some fly ash can be captured using various air pollution control technologies.

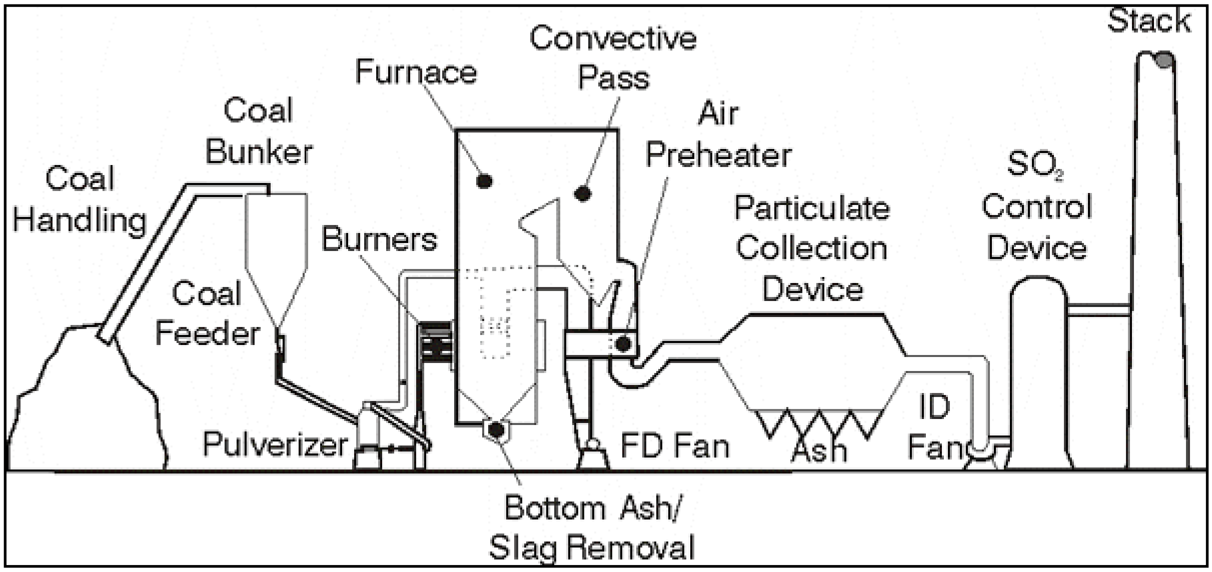



**Figure 7 –** Schematic diagram of a typical pulverized coal power stations (Naini et al., 2005).

### *2.2.3.2 Integrated Gasification Combined Cycle (IGCC)*

Integrated Gasification Combined Cycle (IGCC) uses coal gasification technologies. In coal gasification, coal is gasified by partial combustion to produce synthetic gas. This process uses a gasification agent consisting of air, oxygen and steam.

IGCC combines gas and steam turbines for electricity production. A schematic of an IGCC power plant is presented in Figure 8. Coal slurry is reacted with oxygen (or air) and steam, and syngas is produced, consisting mainly of CO and hydrogen. The raw syngas is cooled and cleaned to remove particulates and sulphur impurities. The clean syngas is burned in a combustion turbine which drives a generator to produce electricity. The hot exhaust gases are recovered and used to produce steam. The resulting steam is used to drive a steam turbine, which turns a generator and produces additional electricity.

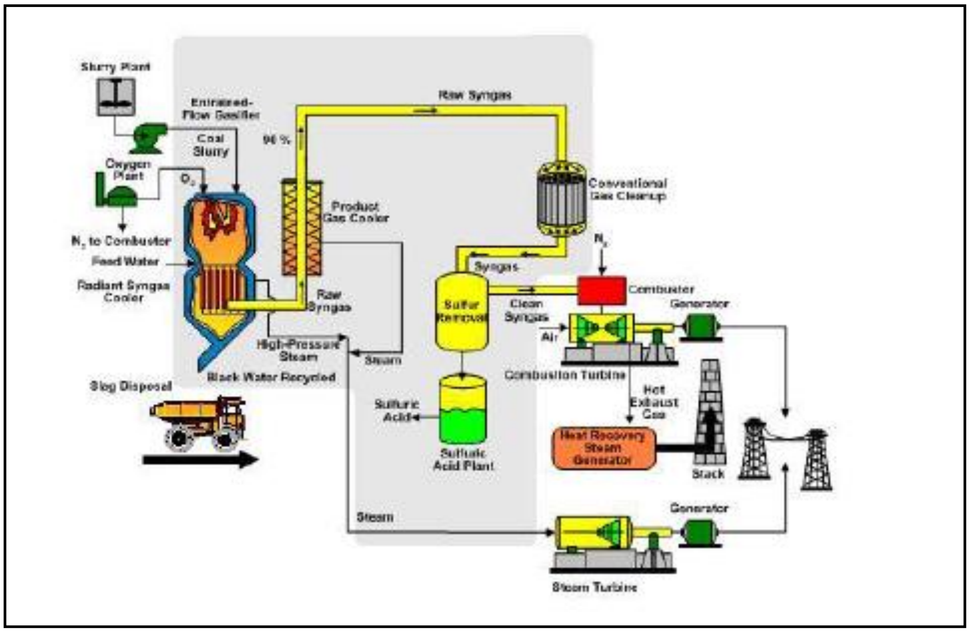



**Figure 8 –** Schematic diagram of typical Integrated Gasification Combined Cycle power station (Naini et al., 2005).

### *2.2.4 Hydroelectric Power Stations*

Hydroelectric power stations generate electricity using the force of water that falls into turbines and rotates the shaft of the turbines. By rotating the shaft of turbines, the potential energy of the water is converted into kinetic energy. The shaft from the turbine is connected to a generator. The kinetic energy from the shaft turns the electrical generator and produces electricity.

Water for use in hydroelectric power stations can be obtained by building a dam on a large river. Water is stored behind the dam in large reservoirs and can be released onto turbine propellers through a dam water intake. After passing through the turbine, the water is released back into the river.

### *2.2.5 Wind Power Plants*

Wind power plants generate electricity by using wind to turn wind turbines. In principle, wind's potential energy is converted to kinetic energy that rotates the blades of turbines, which in turn transfer this energy to an electrical generator. The electrical generators produce electricity.

### 2.2.6 Ontario-Manitoba Interconnection Project

The Ontario-Manitoba Interconnection (OMI) project aims to provide a long-term hydroelectric supply of electricity to Ontario via a cross-province transmission infrastructure. The total capacity of the OMI project is estimated to be from 1,500 MW to 3,000 MW (Ontario Power Authority, 2005). The electricity supply would come from a new hydroelectric power plant constructed at the Conawapa site on the Nelson River in Manitoba. If approved, the supply of electricity may be available to Ontario as early as 2012.

### 2.2.7 Comparison of Supply Technologies

In this section, the various supply technologies are compared in terms of operating characteristics, cost, and environmental impacts.

Nuclear power plants do not emit any GHGs or ozone precursors during normal operation. However, there are radioactive emissions from nuclear power plant's operation. These emissions have been found to be less than the radioactive emissions from coal-fired power plants (Naini et al., 2005). Capital costs and construction periods of nuclear power plants are generally higher than for coal or gas power stations. However, the fuel costs are considerably lower (Ontario Power Authority, 2005).

Natural gas power stations costs depend on the size of the power plant and the selected turbine technology. Simple cycle gas turbines have lower capital costs than combined cycle and cogenerators, but generally have lower efficiency. One advantage of simple cycle gas turbines is that they have fast start-up times and can hence provide electricity for peak-load demand. However, since they do not have long operating times, simple cycle gas turbines are not efficient for base-load service. NGCC's have higher capital costs than simple cycle gas turbines, but lower operating costs. Also, NGCC is generally more efficient then simple cycle gas turbines. NGCC's can be used for base-load or peak-load. Cogeneration has higher capital costs than NGCC's and simple cycle gas turbines, but higher efficiency (Ontario Power Authority, 2005).

Coal power stations generally have lower fuel costs than other fossil fuels. IGCC power plants generally have higher capital costs than other competing technologies. Also, IGCC power plants have higher operating costs than pulverized coal power stations. Coal power plants emit pollutants, such as $CO_2$, NOx, $SO_2$ and particulates. In addition, combustion of coal results in the release of mercury, benzene and formaldehydes. Radioactive elements such as radon and uranium are also released from coal power stations. Whereas pulverized coal power stations produce fly ash, none is generated by IGCC plants.

Use of hydroelectric power stations for electricity production is usually cheaper than use of other technologies because there are no fuel costs associated with hydroelectric plants. Also, the efficiency rate of electricity produced from hydro sources is about double compared to fossil fuel plants (Naini et al., 2005). However, hydroelectric plants depend on water availability which makes electricity production vulnerable to seasonal droughts and changes in weather.

Hydroelectric power stations do not generate any GHGs or other atmospheric emissions. However, there are some negative environmental implications associated with hydroelectricity production. Notably, hydroelectricity generation has adverse impacts on agriculture and river ecological system since dams can lower water tables, alter water temperatures and damage water wildlife.

Similarly to hydroelectric power stations, wind power plants have no fuel costs associated with their operation since they use wind energy to produce electricity. However, wind power plants heavily depend on wind conditions. Moreover, wind is intermittent by nature and the electricity generated by wind turbines will vary depending on wind strength (Ontario Power Authority, 2005).

## *2.3 Carbon Capture and Storage*

Carbon capture and storage (CCS) has received widespread interest as a potential method for controlling and reducing $CO_2$ emissions from fossil fuel power plants (Roa & Rubin, 2002). The basic design of a CCS system includes four fundamental processes. The first process involves the separation and concentration of the $CO_2$ present in the gas stream of fossil fuel power plants. Once the $CO_2$ is separated and concentrated to a nearly pure form, it is compressed beyond its critical value in order to convert the concentrated $CO_2$ gas into a liquid phase and allow for liquid phase transportation. The third stage of the process involves the transport of the concentrated liquid $CO_2$ stream via a network of pipelines to a storage location. Finally, the last stage of the process is the sequestration of the $CO_2$ into a medium such as a deep saline aquifer or a depleted oil and gas reservoir for long term storage (Benson & Surles, 2006). A schematic of a hypothetical CCS system is illustrated in Figure 9.

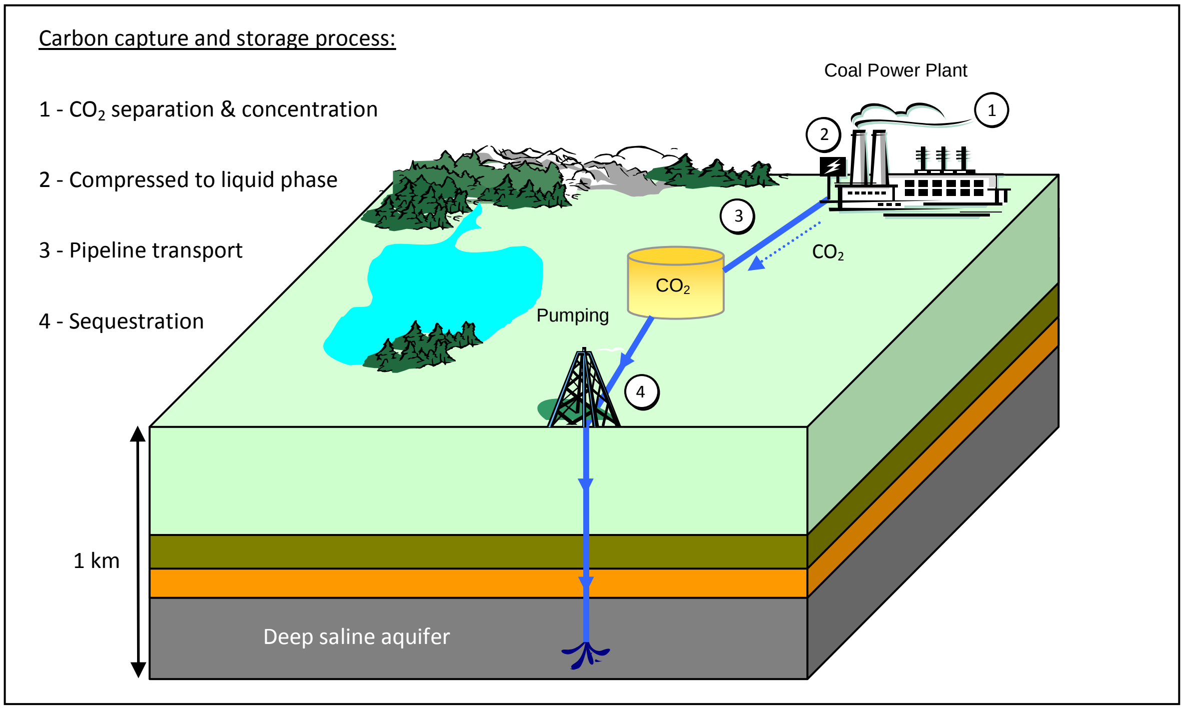



**Figure 9 -** Schematic diagram of a hypothetical carbon capture and storage system that uses a deep saline aquifer for long term storage of carbon dioxide.

A CCS system can be implemented on any new or existing power plant in order to reduce and control $CO_2$ emissions. The cost associated with retrofitting an existing power plant with a CCS system generally tends to be higher than of a new power plant with a CCS system already in place. This cost difference is largely due to the higher energy penalty that is incurred by less efficient heat integration as well as potential site specific difficulties that are inherent in most retrofit projects (Rao & Rubin, 2002). Although the cost of retrofitting an existing power plant with a CCS system may be higher, this may potentially be outweighed by the benefit of maintaining the operation of the power plant, while meeting $CO_2$ emission targets, without having to build a new plant.

## *2.3.1 Carbon Capture Technologies*

There exist a wide range of technologies that are currently available in order to separate and capture $CO_2$ present in a gas streams. The carbon capture technologies available can be grouped in three general categories: post-combustion capture, pre-combustion capture and oxy-fuel combustion.

A post-combustion carbon capture process involves the removal of $CO_2$ from the flue gas of power plants. The most common method for post-combustion carbon capture is a chemical absorption process that uses monoethanolamine (MEA) as a solvent. The process consists of running the flue gases through a low pressure gas/liquid absorber were the $CO_2$ is removed from the flue gas by partitioning with the amine solver. The amine is then heated to a specific temperature in order to release the pure $CO_2$ and regenerate the solvent.

Pre-combustion capture processes involve the removal of most of the carbon content in a fossil fuel before it is combusted. The process involves the pre-combustion reaction of the fossil fuel with steam and air, producing a syngas that is comprised of primarily CO and $H_2$. The CO is then reacted with water to produce a mixture of $CO_2$ and additional $H_2$, which can then be separated and utilized for energy production and the $CO_2$ stored respectively (Benson & Surles, 2006).

### *2.3.2 Carbon Dioxide Sequestration in Ontario*

Carbon dioxide sequestration refers to long term and safe storage of carbon dioxide in a medium such as a deep saline aquifer or a depleted oil and gas reservoir. The process of carbon dioxide sequestration is normally performed after the carbon dioxide has been separated and captured from the gas stream of a power plant by a suitable process.

In Ontario, two large reservoirs for $CO_2$ sequestration have been identified, one located in the southern part of Lake Huron and the other located within Lake Erie. The approximate storage capacity for these two reservoirs has been estimated to be 289 and 442 million tonnes of $CO_2$, respectively (Shafeen, Croiset, Douglas, & Chatzis, 2004a). In order to achieve the estimated storage capacity of the reservoir, the injected $CO_2$ must maintain a temperature and pressure condition beyond its critical value. This supercritical state of $CO_2$ increases the density of the $CO_2$ and allows large quantities of $CO_2$ to be stored in a relatively small volume. The supercritical state of $CO_2$ can only be maintained if it is stored at a minimum reservoir depth of 800 m (Shafeen, Croiset, Douglas, & Chatzis, 2004b). Figure 10 illustrates the geographical location of the two potential reservoirs for $CO_2$ sequestration in Ontario.


**Figure 10 –** Geographical location of two potential reservoirs that may be utilized for $CO_2$ storage. The two reservoirs identified are Lake Huron and Lake Erie.

## 2.4 Ontario's Current Energy Mix

Ontario's current energy mix is composed of a variety of supply sources. The main technologies supplying electricity to Ontario are nuclear, hydroelectric, coal, natural gas and oil. The current installed capacity from all the supply sources totals approximately 30,662 MW (Ontario Power Authority, 2005). Table 1 presents the installed capacity of each supply technology in Ontario's energy mix.

**Table 1 –** Ontario's current installed capacity based on supply sources (Ontario Power Authority, 2005).

| Technology | Existing Capacity (MW) |
|---|---|
| Nuclear | 11,397 |
| Hydroelectric | 7,756 |
| Coal | 6,434 |
| Gas/Oil | 4,976 |
| Other | 99 |
| **Total** | **30,622** |

### 2.4.1 Nuclear

Nuclear power plays a very important role in Ontario's energy supply mix. Currently, nuclear power accounts for approximately 37% of Ontario's installed capacity and provides over 50% of Ontario's electrical energy needs.

There are currently three CANDU nuclear power plants in Ontario: Pickering generating station, Darlington generating station and Bruce Power. Table 2 outlines the nuclear units available in Ontario and the expected operational lifespan of each unit. The end-of-service dates presented in Table 2 are uncertain estimates which may change based upon various factors such as refurbishment strategies and maintenance practices over the next few years.

**Table 2 –** Operational and out-of-service nuclear units in Ontario. The data presented in this table includes the gross capacity, first commercial operation and the estimated end-of-service date for each nuclear unit in Ontario.

| | Unit | Status | Gross Capacity (MW) | First Commercial Operation | End of Service Dates |
|---|---|---|---|---|---|
| **Pickering Nuclear Plant** | | | | | |
| Pickering A | Unit 1 | Operational – was returned to service in 2005 | 515 | 07/1971 | n/a |
| | Unit 2 | Out of Service | 515 | 12/1971 | n/a |
| | Unit 3 | Out of Service | 515 | 06/1972 | n/a |
| | Unit 4 | Operational – was returned to service in 2003 | 515 | 06/1973 | 2016 |
| Pickering B | Unit 5 | Operational | 516 | 05/1983 | 2008 |
| | Unit 6 | Operational | 516 | 02/1984 | 2009 |
| | Unit 7 | Operational | 516 | 01/1985 | 2010 |
| | Unit 8 | Operational | 516 | 01/1986 | 2011 |
| **Bruce Nuclear Plant** | | | | | |
| Bruce A | Unit 1 | Refurbished: Expected start date 2009 | 750 | 09/1977 | n/a |
| | Unit 2 | Refurbished: Expected start date 2010 | 750 | 01/1977 | n/a |
| | Unit 3 | Operational | 750 | 01/1978 | 2012 |
| | Unit 4 | Operational | 750 | 01/1979 | 2016 |
| Bruce B | Unit 5 | Operational | 785 | 03/1985 | 2010 |
| | Unit 6 | Operational | 820 | 09/1984 | 2009 |
| | Unit 7 | Operational | 785 | 04/1986 | 2011 |
| | Unit 8 | Operational | 785 | 05/1987 | 2012 |
| **Darlington Nuclear Plant** | | | | | |
| Darlington | Unit 1 | Operational | 881 | 11/1992 | 2017 |
| | Unit 2 | Operational | 881 | 10/1990 | 2015 |
| | Unit 3 | Operational | 881 | 02/1993 | 2018 |
| | Unit 4 | Operational | 881 | 02/1993 | 2018 |

As shown in Table 2, most of the nuclear units were built in the 1970s and 80s and are reaching the end of their expected service life. Consequently most nuclear units will need to be retired or refurbished before 2018 (Winfield, Horne, McClenaghan, & Peters, 2004).

Refurbishment of the existing nuclear units in Ontario would involve a wide range of work and require a great deal of economic investment. The most significant part of the refurbishment process, and incidentally the most expensive, is the replacement of the fuel channels of the reactors, a process referred to as Large Scale Fuel Channel Replacement (LSFCR). The LSFCR refurbishment process involves the restoration of the nuclear reactor core and requires the shut-down of the nuclear unit for a period of at least two years (Winfield et al., 2004).

### 2.4.2 Coal

Ontario's coal-fired power plants are a significant part of the current supply mix. Coal power plants account for approximately 21% of Ontario's installed capacity and provide for 19% of Ontario's electricity generation requirements.

Ontario currently operates four coal-fired power plants and one duel fuelled oil and natural gas power plant. The coal power plants are Lambton, Nanticoke, Atitokan, and Thunder Bay. The oil and natural gas power plant is the Lennox generating station. Table 3 presents the existing coal-fired power plants in Ontario.

**Table 3 –** Existing coal-fired power plants in Ontario.

| | Fuel | No. of Units | Capacity (MW) | % of fossil fuel capacity | Dates in service |
|---|---|---|---|---|---|
| Nanticoke | Coal | 8 | 3938 | 46 | 1973/1978 |
| Lambton | Coal | 4 | 1975 | 23 | 1969/1970 |
| Thunder Bay | Coal | 2 | 310 | 4 | 1981/1982 |
| Atikokan | Coal | 1 | 215 | 3 | 1985 |
| Lennox | Oil/Gas | 4 | 2140 | 25 | 1976/1977 |

### 2.4.3 Hydroelectric

In Ontario, hydroelectric power accounts for approximately 26% of the installed capacity available to the province, and provides for 23% of the electricity generation. There are currently 108 hydroelectric stations within Ontario, but only 58 stations are directly connected to the electricity grid (Ontario Ministry of Energy, 2005). The largest hydroelectric stations in Ontario are the Niagara Plant Group which operate on the Niagara River and at DeCew Falls in St.Catharines. These stations have a combined capacity of 2,278 MW (Ontario Power Generation, 2006).

### 2.4.4 Natural Gas

Currently, Natural Gas accounts for approximately 7% of the supply mix in Ontario. There are presently 60 Natural Gas power plants of various capacities in Ontario, but only 19 of these stations are connected to Ontario's electricity grid. The total installed capacity of all the natural gas-fired generating stations is approximately 2,100 MW (Ontario Ministry of Energy, 2007).

## 2.5 Future Outlook

### 2.5.1 Electricity Demand Forecast

A load duration curve is often used to help plan for electrical utilities. A typical curve is presented in Figure 11 (Murphy, Sen, & Soyster, 1982).

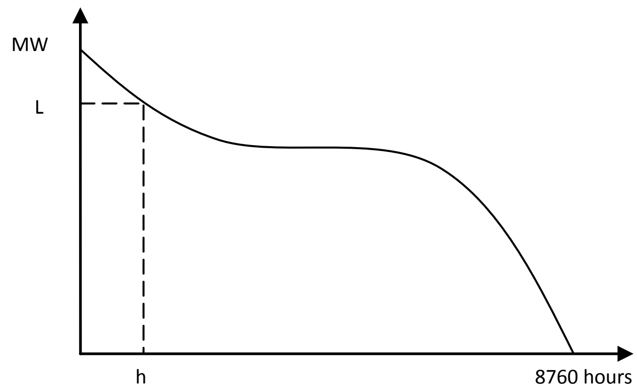



**Figure 11 –** Typical load-duration curve.

From Figure 11, *h* is the number of hours in a year during which the demand is greater than or equal to a given load *L* (MW). The area under the curve represents the amount of energy, given in megawatt-hours, for a given period of time.

For large-scale applications, such as large nuclear units and gas turbines, the load duration curve can be simplified using linear approximation. A typical two-step linear approximation is given in Figure 12.

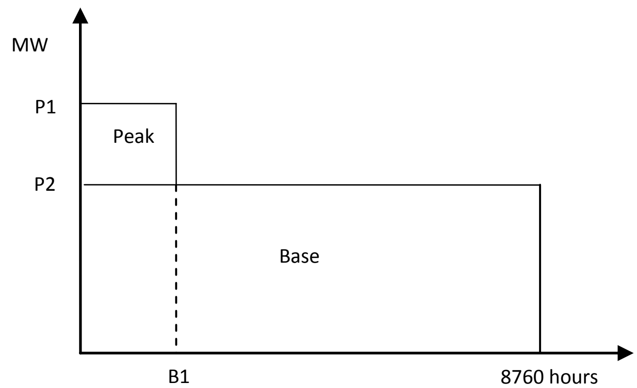



**Figure 12 –** Linear approximation of load-duration curve.

From Figure 12, a specific generating unit is assumed to operate in base-mode and/or peak-mode. This two-step linear approximation is used in this dissertation in order to simplify the problem.

Various electricity demand forecasts for Ontario have been published. In 2005, Independent Electricity System Operator (IESO) forecasted the energy and peak-load demand for Ontario for the ten-year period from 2006-2015. The results show that the energy demand is predicted to grow by 0.9% annually over the forecast period. Total energy demand is expected to increase from 157 TWh to 170 TWh by 2015. IESO predicts an increase in the normal weather peak from 24,200 MW in 2006 to 25,700 MW in 2015, while the normal weather summer peak is expected to increase from 24,000 MW to 26,900 MW over the same time period. Furthermore, the forecast shows an average annual increase of 0.7% for the winter peak and an average annual growth rate of 1.3% for the summer peak (IESO, 2006).

Navigant Consulting Ltd. used IESO 2005 forecast to extrapolate electricity demand to 2025. In this forecast, annual hourly data was extracted from IESO's forecast for the period of 2006-2015. For the remaining analysis period of 2016-2025, the 2015 typical week profile was extrapolated and fit to the annual energy and peak demand forecast (Navigant Consulting, 2005). The Ontario peak demand and energy consumption forecasts from Navigant Consulting Ltd. are shown in Table 4 below.

**Table 4 –** Forecasted peak demand (MW) and energy demand (TWh) from Navigant Consulting Ltd.

| | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 |
|---|---|---|---|---|---|---|---|---|---|---|
| Annual Energy (TWh) | 156.8 | 158.3 | 160.3 | 161.2 | 162.6 | 164.2 | 166.0 | 167.0 | 168.4 | 169.7 |
| Peak Demand (MW) | 24,205 | 24,374 | 24,627 | 25,045 | 25,228 | 25,534 | 25,840 | 26,461 | 26,461 | 26,874 |

| | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|---|---|---|---|
| Annual Energy (TWh) | 171.2 | 172.7 | 174.3 | 175.8 | 177.4 | 178.9 | 180.5 | 182.1 | 183.7 | 185.3 |
| Peak Demand (MW) | 27,211 | 27,552 | 27,898 | 28,248 | 28,602 | 28,961 | 29,692 | 29,692 | 30,064 | 30,441 |

Chui, Elkamel, Croiset, and Douglas (2006) used a stochastic model to forecast Ontario's electricity demand from 2006 to 2020. In this model, employment forecasts from the Ontario Ministry of Finance and various weather scenarios were used to predict electricity demand. This forecast contains a lower, median, and upper bound. The lower bound uses a low employment growth rate and mild weather conditions, while the median bound uses median employment growth rate and median weather scenarios. Finally, the upper bound uses high employment growth rate and extreme weather scenarios. The forecasted annual energy demand, annual peak-load demand, and annual base-load demand from Chui et al. (2006) are shown in Figure 13, 14, and 15 respectively.

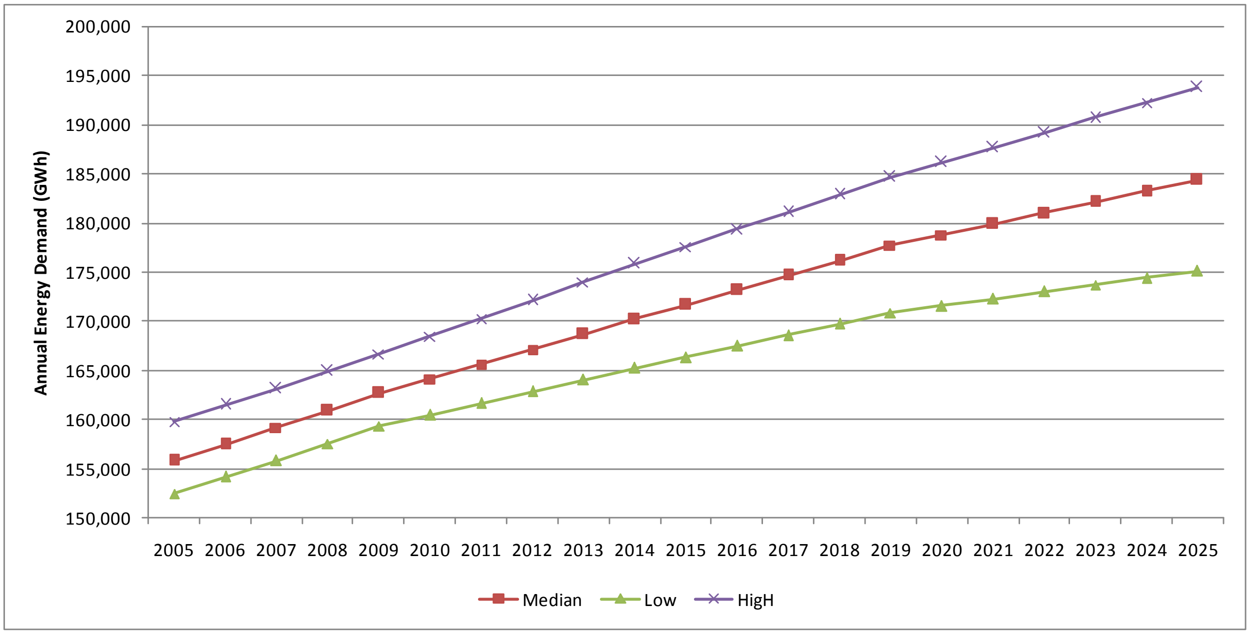



**Figure 13 –** Ontario's forecasted Annual Energy demand (GWh) for low, median and upper bound (Chui et al.,2006).

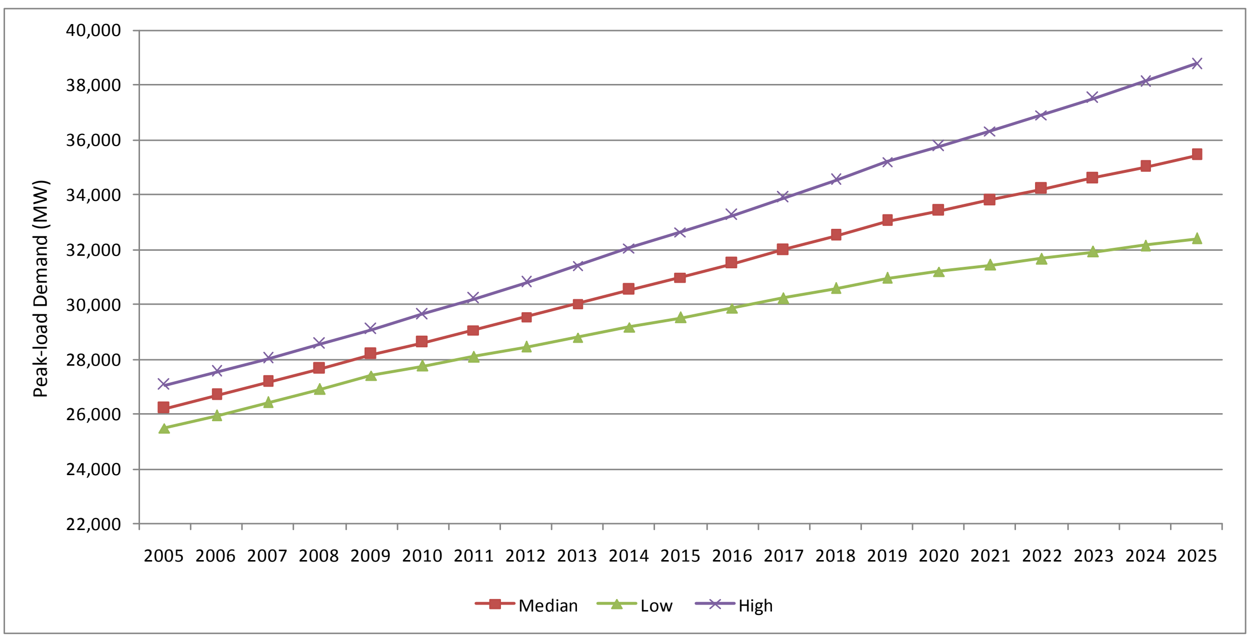



**Figure 14 –** Ontario's forecasted annual peak-load demand (MW) for low, median, and upper bound (Chui et al.,2006).

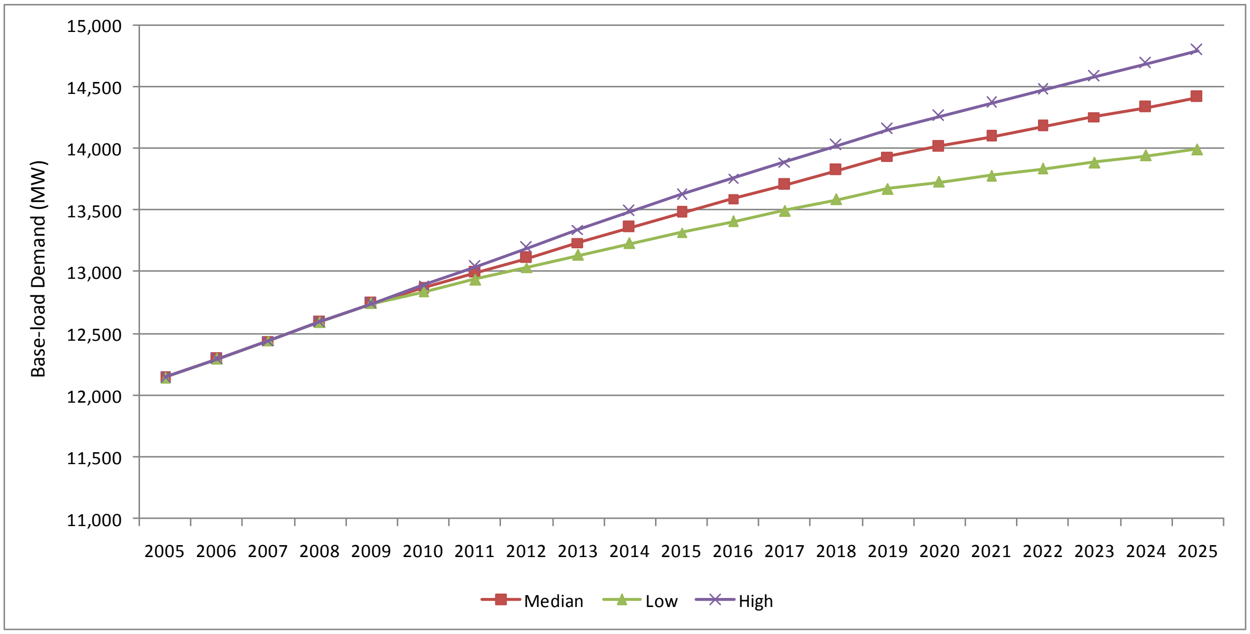



**Figure 15 –** Ontario's forecasted annual base-load demand (MW) for low, median, and upper bound (Chui et al.,2006).

As can be seen from Figure 13, Ontario's annual energy demand grows by a range of 0.7% to 0.97% from year 2006 to 2020. Figure 14 shows an annual increase in peak-load demand in the range of 1.21% to 1.82% for the same time period. Finally, from Figure 15 it can be seen that the annual base-load demand grows in the range of 0.71% to 0.99%.

This thesis paper uses the electricity forecast estimated by Chui et al. (2006) for the case studies discussed in Chapter 4. The data for annual energy demand, annual peak-load demand, and annual base-load demand used in the model is presented in Appendix A.

### *2.5.2 Fuel Price Forecast*

Future fuel prices in North America will be affected by numerous factors, such as demand growth, productive capacity, and the type of supply sources. For instance, the prices may vary depending on the availability of conventional and non-conventional supply sources and the industry's cost and ability to bring them to market.

### 2.5.2.1 Natural Gas Price Forecast

There are numerous natural gas price forecasts reported in literature. Sproule forecasted natural gas prices based on Henry Hub daily closing prices. Based on this forecast, an upward trend was observed from 1997 to 2007, and prices were expected to fall in 2008 as the new set of Liquefied Natural Gas (LNG) terminals come on-line (Naini et al., 2005). The Energy Information Administration's (EIA) Annual Energy Outlook (AEO) was released in 2005 and forecasts for the Lower 48 US Supplier's average wellhead price. Unlike the Sproule forecast, the EIA's AEO2005 forecast does not include the transportation costs of delivering natural gas to costumers and is hence based on lower prices than Henry Hub. The AEO2005 forecasts natural gas prices rising until 2008, and falling after the new LNG terminals come on-stream (Naini et al., 2005).

This paper uses the National Energy Board's (NEB) natural gas price forecasts. The NEB forecasts natural gas prices delivered to industrial consumers in Ontario. It is based on two scenarios: a Supply-Push (SP) case and a Techno-Vert (TV) case. The SP scenario is based on an assumption that technology advances gradually and that there is limited action on the environment in Canada. One of the major premises of the SP case is the security and development of conventional North American gas sources using proven technologies.

The TV scenario is based on the assumption that technology advances occur more rapidly and that Canadians take broad action on the environment. The heightened concern for the environment is assumed to result in an increasing demand for cleaner fuels and advances in technology. The outcome is rapid technological advances resulting in development of non-conventional gas sources (Naini et al., 2005).

The NEB's forecast is presented in Figure 16. Numerical data for the annual NG forecast is presented in Table 29 of Appendix B.

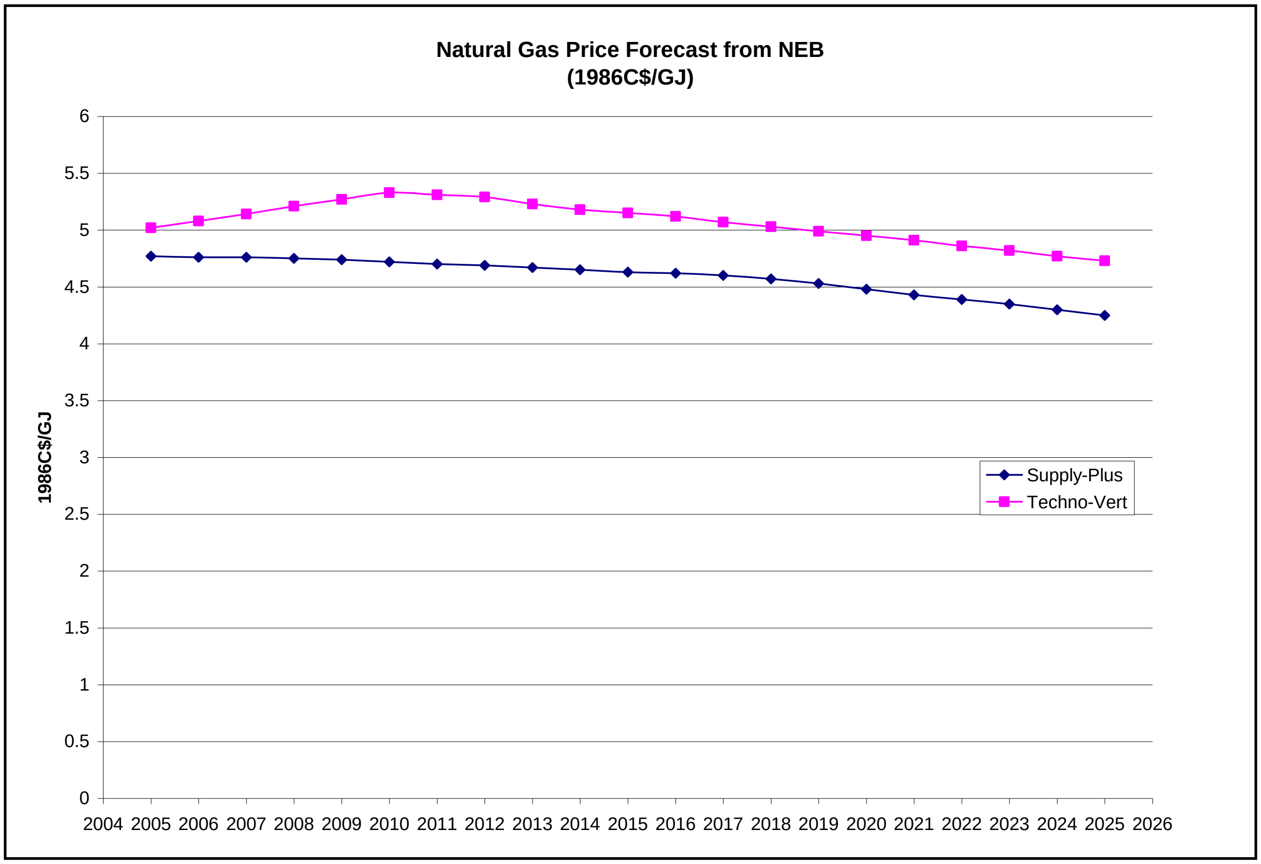



**Figure 16 -** Natural gas forecast from NEB showing both Supply-Plus and Techno-Vert scenarios. Numerical data for the annual natural gas forecast is presented in Table 29 of Appendix B. Costs are expressed in terms of 1986 Canadian dollars.

From Figure 16, the natural gas prices are forecasted to decrease after 2010 for both SP and TV scenarios. The TV scenario predicts a slight increase in prices between 2006 and 2010. Similarly to Sproule and AEO's outlooks, the gas price decrease may be a result of the assumption that LNG terminals come-on stream after 2010.

### *2.5.2.2 Coal Price Forecast*

Sproule and EIA's AEO2005 forecasts predict coal prices, measured in terms of US export price of coal, to decline from 2007 to 2025. AEO2005 forecast indicates coal prices will not drop below 2003US$ 35/short ton for the next two decades (Naini et al., 2005).

This paper uses coal price forecasts from the NEB. The NEB coal price forecast is shown in Figure 17. Numerical data for the annual NG forecast is presented in Table 30 of Appendix B.

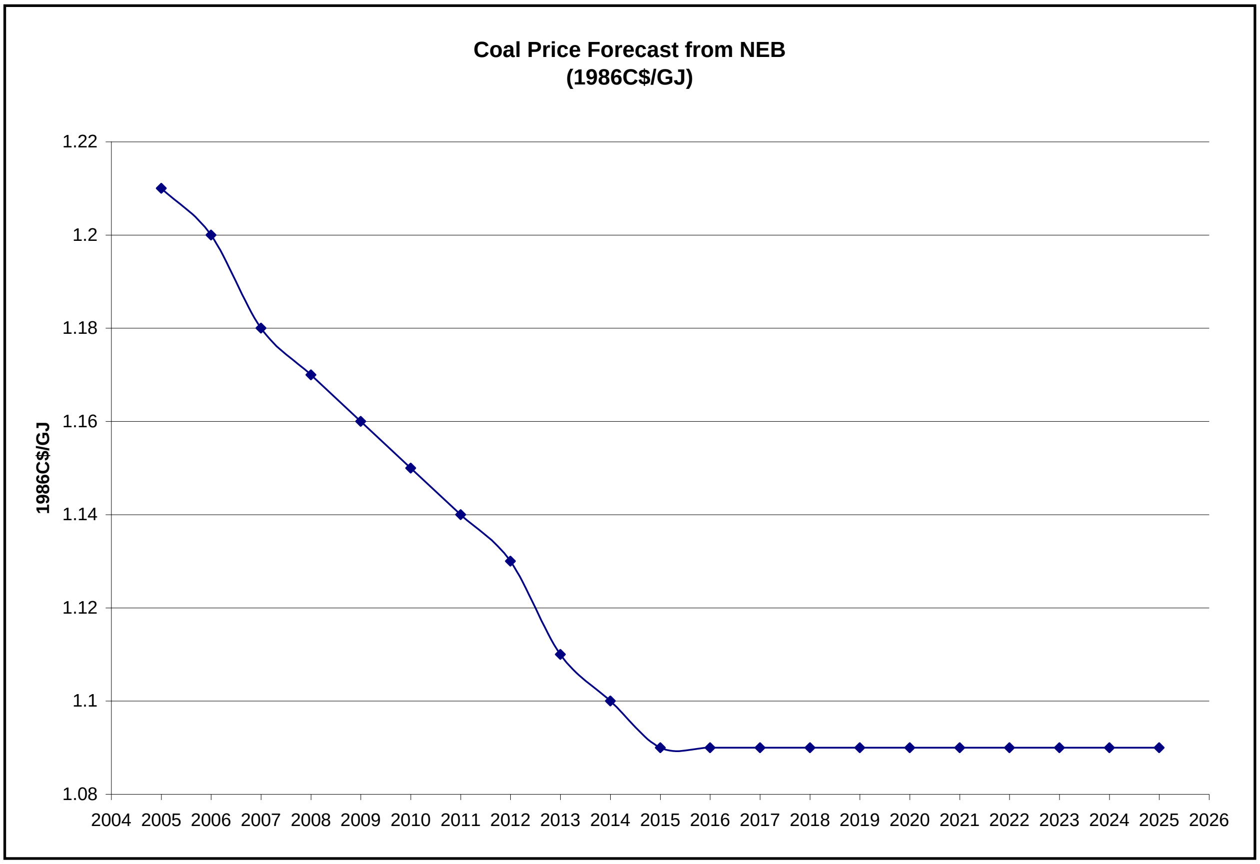



**Figure 17 –** Coal price forecast from NEB. Numerical data for the annual coal forecast is presented in Table 30 of Appendix B. Costs are expressed in terms of 1986 Canadian dollars.

From Figure 17, NEB's coal prices are measured as delivered prices to industrial consumers in 1986 Canadian dollars per GJ coal. NEB projects coal prices to decline by one percent until year 2015, after which time the coal prices are expected to remain constant. It is assumed that there are no significant resource constrains on coal production. Also, continuing efficiency improvements such as mergers in the transportation industry are assumed.

### *2.5.3 Energy Conservation Strategy*

Historically, conservation has occurred naturally with advances in technology. For instance, home appliances have been replaced by more efficient ones and building materials have become more energy-conserving with technological advances. Such energy efficiency improvements are known as "technology improvements" and are typically reflected in demand forecasts.

Conservation and Demand Management (CDM) is the use of a wide range of activities in an effort to reduce consumer demand and use of electricity. CDM usually results in higher levels of conservation than technology improvements due to more direct intervention in the market through incentives, standards or other mechanisms. The activities undertaken to reduce the use of electricity can be classified into three distinct categories: conservation efforts that result in less than normal use of electricity; energy efficiency activities that result in less electricity utilized for the same level of service; and load management activities to reduce demand during peak times.

Though technology improvements are typically included in demand forecasts, it is often difficult to determine the extent of technology improvement present in such forecasts. For example, the IESO's 10-year Outlook is heavily influenced by past trends and behaviours, and it is thus difficult to quantify the contribution by technology improvements. Furthermore, energy savings due to CDM activities can be substantial but are even more difficult to quantify without detailed information on the programs, tools and standards.

In order to assess electricity conservation potential in Ontario, ICF Consulting has developed a methodology based on a combination of two approaches. The first approach is known as "experience-based", and is based on a review of the effects of energy-conservation programs in various U.S. jurisdictions as well as other efficiency potential analysis. The second approach, known as "accounting approach", is based on an assessment of potential efficiency improvement contributions by various sectors, sub-sectors and end users (Ontario Power Authority, 2005). ICF used a combination of these two complementary approaches to help utilize the strengths of each. Though each approach has its advantages, they also have some inherent weaknesses. For instance, the experience-based approach uses U.S. data that may not be applicable to Ontario.

Using the two approaches described above, ICF considered four scenarios reflecting increasing levels of aggressiveness in energy conservation efforts. Energy Efficiency (EE) 25 refers to information-based programs with financial incentives of 25% of incremental cost of new equipment installation. EE50 are common programs in which financial incentives equal 50% of incremental cost of new equipment installation. EE100 are programs that involve intensive technical assistance and have financial incentives of 100% of incremental cost. Finally, EE100 Plus Standards programs take into account a broad range of aggressive generic standards and also involve financial incentives of 100% of incremental cost (ICF Consulting, 2005). Efficiency improvements estimated by ICF are given in Table 5 and Table 6 below.

Both sets of data assume a hot summer day since efficiency improvement during such weather provide additional energy savings.

**Table 5 –** Estimated energy efficiency peak-demand savings (MW) by ICF. The estimates are divided into four scenarios which reflect the increasing levels of aggressiveness in energy conservation efforts (ICF Consulting, 2005).

| Scenario | 2010 | | 2015 | | 2020 | | 2025 | |
|---|---|---|---|---|---|---|---|---|
| | Est.1 (MW) | Est.2 (MW) | Est.1 (MW) | Est.2 (MW) | Est.1 (MW) | Est.2 (MW) | Est.1 (MW) | Est.2 (MW) |
| EE 25 | 440 | 200 | 600 | 950 | 780 | 1840 | 980 | 2280 |
| EE50 | 1110 | 850 | 1530 | 3050 | 1680 | 4040 | 1490 | 4330 |
| EE100 | 1790 | 1770 | 2040 | 4290 | 1820 | 4800 | 1570 | 4520 |
| EE100 Plus | 2440 | 4620 | 2360 | 5380 | 1960 | 5050 | 1710 | 4730 |

**Table 6 -** Estimated energy efficiency savings (TWh) by ICF. The estimates are divided into four scenarios which reflect the increasing levels of aggressiveness in energy conservation efforts (ICF Consulting, 2005).

| Scenario | 2010 | | 2015 | | 2020 | | 2025 | |
|---|---|---|---|---|---|---|---|---|
| | Est.1 (TWh) | Est.2 (TWh) | Est.1 (TWh) | Est.2 (TWh) | Est.1 (TWh) | Est.2 (TWh) | Est.1 (TWh) | Est.2 (TWh) |
| EE 25 | 3.2 | 1.1 | 4.5 | 5.7 | 5.3 | 12.7 | 5.3 | 17.2 |
| EE50 | 8.2 | 5 | 10 | 20.4 | 8.9 | 27.2 | 6.9 | 27.7 |
| EE100 | 12.2 | 10.9 | 11.9 | 28.3 | 9.3 | 30.4 | 7.1 | 28.2 |
| EE100 Plus | 15.1 | 27.2 | 12.5 | 32.1 | 9.6 | 30.8 | 7.3 | 28.5 |

## 2.6 Journal Review

From our literature review to date, we have found several authors that have used multi-period optimization methods for planning purposes. Iyer, Grossmann, Vasantharajan and Cullick (1998) have developed a multi-period mix-integer linear programming (MILP) model for the planning and scheduling of offshore oil field facilities. This mathematical model employs a general objective function that optimizes a selected economic indicator. Maravelias and Grossmann (2001) proposed a complex multi-period optimization model to address the challenge of planning for the production of a new product in highly regulated industries, such as pharmaceuticals and agrochemicals. The model uses a multi-period MILP model that maximizes the expected net present value of a multi-period project. The model, although comprehensive, does not account for the lead time required for construction of new plants. Mo, Hegge and Wangensteen (1991) developed a stochastic dynamic model for handling the uncertainties in generation expansion problems. The model makes it possible to identify the connection between investment decisions, time, construction periods, and uncertainty.

Hashim, Douglas, Elkamel and Croiset (2005) developed a single-period deterministic MINLP optimization model aimed to predict a fleet-wide system configuration which simultaneously satisfies electricity demand and $CO_2$ emission constraints at minimum cost. The mathematical model developed was linearized using exact linearization techniques in order to overcome the inherited problems with solving non-linear models. Although the model developed by Hashim et al. (2005) is very comprehensive and complex, its single period mathematical structure does not allow the incorporation of multi-period factors such as construction lead time and fuel price fluctuations over time. In order to improve the optimization model and make it more realistic, the model developed by Hashim et al. (2005) must be extended to a multi-period domain.

From the journal review conducted, no publication was found addressing the problem of finding the optimal strategy for energy planning with $CO_2$ emission constraints and the option to implement carbon capture and storage. This thesis involves the development of a novel deterministic multi-period MINLP optimization model in order to realize the optimal mix of energy supply sources, while meeting $CO_2$ emissions targets.

# Chapter 3

## 3.1 Model Formulation

The formulation developed is a multi-period Mixed Integer Linear Programming (MILP) model that is able to realize the optimal mix of energy supply sources which will meet current and future electricity demand, $CO_2$ emission targets, and minimize the overall cost of electricity. The model presented is initially a Mixed Integer Non-Linear Programming (MINLP) model that is then linearized using exact linearization methods. The linearization of the non-linear model is done with the aim of avoiding inherited computational difficulties encountered with large convex non-linear models. This linearization is able to lower the computation expense while retaining the consistency of the solution.

The developed model was programmed and implemented in the GAMS (General Algebraic Modeling System) optimization package and solved using the CPLEX 10 solver. The GAMS code is included in Appendix C.

The indices, sets, variables, and parameters used in the planning model are the following:

**Indices**

| | |
|---|---|
| $t$ | Time period (years) |
| $i$ | Boiler |
| $j$ | Fuel type (coal or natural gas) |
| $l$ | Load block (peak or base-load) |
| $k$ | Carbon capture technology |

**Sets**

| | |
|---|---|
| $F$ | Fossil fueled power plants |
| $NF$ | Non-fossil fueled |
| $new$ | New power plants |
| $new-cap$ | New power plants with carbon capture |

**Parameters**

| | |
|---|---|
| $F_{ijt}$ | Fixed operating cost of boiler i using fuel j during period t ($/MW) |
| $V_{ijt}$ | Variable operating cost of boiler i using fuel j during period t ($/MWh) |
| $C_{ij}$ | Capacity of boiler i using fuel j (MW) |
| $P_{lt}$ | Duration of load block l during period t (hrs) |
| $U_{jt}$ | Fuel cost for fuel j during period t ($/GJ) |
| $G_{ij}$ | Heat rate of boiler i using fuel j (GJ/MWh) |
| $R_{it}$ | Cost associated with fuel-switching coal-fired boiler i during period t |
| $S_{it}$ | Capital cost of power plant i during period t |
| $(CCost)_t$ | Cost of carbon credits during period t ($/tonne of $CO_2$) |
| T | Time horizon (years) |
| $(CO2)_{ij}$ | $CO_2$ emission from boiler i using fuel j (tonne of $CO_2$/MWh) |
| $E_k^{max}$ | Maximum supplemental energy required for $k^{th}$ capture technology |
| $\varepsilon_{ikt}$ | Percent of $CO_2$ captured from boiler i using carbon capture technology k during period t (%) |
| $\beta_i$ | Construction lead time for power station i (years) |
| $Q_i$ | Cost of carbon capture and storage for boiler i ($/tonne of $CO_2$) |
| $D_{tl}$ | Electricity demand during period t for load l (MWh) |
| $B_{tl}$ | Conservation and demand management during period t and load block l (MWh) |
| $\rho$ | Factor for transmission and distribution losses |
| $CLimit_t$ | Specified $CO_2$ limit during period t |

**Binary variables**

| | |
|---|---|
| $n_{it}$ | =1 if power plant i is built during period t<br>= 0 otherwise |
| $y_{it}$ | =1 if power plant i is operational during period t<br>= 0 otherwise |
| $x_{ijt}$ | =1 if coal-fired boiler i is operational while using fuel j during period t<br>=0 otherwise |
| $z_{ijkt}$ | =1 if the carbon capture technology k is used on boiler i, which uses fuel j, during period t. |
| $h_{it}$ | =1 if coal-fired boiler i undergoes fuel-switching during period t<br>=0 otherwise |

**Continuous variables**

| | |
|---|---|
| $E_{ijlt}$ | Power allocation from boiler i using fuel j for load block l during period t (MW) |
| $(Cre)_t$ | Carbon credits purchased during period t (tonne of $CO_2$) |

## 3.2 Objective Function

The objective function of the planning model is to minimize the total discounted present value of the costs associated with meeting electricity demand while satisfying a $CO_2$ reduction target over a specified planning horizon. The components associated with the objective function include: fixed and variable operating and maintenance cost, fuel cost, retrofit cost, capital cost for new power plants, carbon capture and storage cost, and cost of purchasing carbon credits.

The objective function for the deterministic multi-period MINLP model is as follows:

$$\min \ f(i,j,k,l,t) = \underbrace{\sum_{i\in F}\sum_{j}\sum_{t} F_{ijt}^{F} C_{ij}^{F} x_{ijt} + \sum_{i\in NF}\sum_{t} F_{it}^{NF} C_{i}^{NF} y_{it}^{NF}}_{Fixed\ O\&M\ cost\ of\ existing\ power\ plants} + \underbrace{\sum_{i\in F}\sum_{j}\sum_{l}\sum_{t} V_{ijt}^{F} E_{ijlt}^{F} P_{lt} + \sum_{i\in NF}\sum_{l}\sum_{t} V_{it}^{NF} E_{ilt}^{NF} P_{lt}}_{Variable\ O\&M\ cost\ of\ existing\ power\ plants} +$$

$$\underbrace{\sum_{i\in F}\sum_{j}\sum_{l}\sum_{t} U_{jt} G_{ij}^{F} E_{ijlt}^{F} P_{lt}}_{Fuel\ cost\ for\ fossil\ fuel\ plants} + \underbrace{\sum_{i\in F}\sum_{t} R_{it} h_{it}}_{\substack{retrofit\ cost\ for\\ fuel\ switching}} + \underbrace{\sum_{i\in P^{new}}\sum_{t} S_{it}^{new} C_{i}^{new} n_{it}}_{\substack{capital\ cost\ for\ new\\ power\ plant}} + \underbrace{\sum_{i\in P^{new}}\sum_{t} F_{it}^{new} C_{i}^{new} y_{it}^{new}}_{\substack{Fixed\ O\&M\ cost\ of\ new\\ power\ plant}} +$$

$$\underbrace{\sum_{i\in P^{new}}\sum_{l}\sum_{t} V_{it}^{new} E_{ilt}^{new} P_{lt}}_{\substack{Variable\ O\&M\ cost\ of\ new\\ power\ plant}} + \underbrace{\sum_{i\in P^{new}}\sum_{l}\sum_{t} U_{it} G_{i}^{new} E_{ilt}^{new} P_{lt}}_{\substack{Fuel\ cost\ for\ new\\ power\ plant}} + \underbrace{\sum_{t} (Cre)_t (CCost)_t}_{\substack{Cost\ of\ purchasing\ CO2\\ emission\ credits}} +$$

$$\underbrace{\sum_{i\in F}\sum_{j}\sum_{k}\sum_{l}\sum_{t} Q_i (CO2)_{ij}\, \varepsilon_{ikt} E_{ijlt}^{F} z_{ijkt} P_{lt}}_{\substack{Carbon\ capture\ and\ storage\ cost\\ for\ existing\ power\ plants}} + \underbrace{\sum_{i\in P^{new-cap}}\sum_{l}\sum_{t} Q_i (CO2)_i\, \varepsilon_{ikt} E_{ilt}^{new} P_{lt}}_{\substack{Carbon\ capture\ and\ storage\ cost\\ for\ new\ power\ plants}}$$

The construction of new power plants involves the use of postulated power plants that have a pre-assigned capacity and operational parameter. Energy production from these new hypothetical power plants can only occur if the optimizer has previously decided to build the new power plant. Several constraints, which are discussed in the next section, have been formulated in order to prevent the generation of electricity from new power plants that have not been constructed.

It is important to note that no binary variable is associated with the cost of CCS for new power plants. For new power stations, the option to have a carbon capture system in place is dependent on which power station is chosen. For every hypothetical new power station there is an equivalent power station, with a similar capacity and operational parameters, that has an integrated CCS system. The optimizer considers the two corresponding power plants and will decide whether to build the power plant with a CCS or the one without CCS.

The non-linear term in the objective function comes from the equation that considers the CCS for existing power plants. This non-linearity is due to the cross-product of the binary variable $z_{ijkt}$ (decision whether to put the k[th] carbon capture technology on the i[th] boiler using the j[th] fuel during time period t) and the continuous variable $E_{ijtl}^{F}$ (power allocation from i[th] fossil fuel boiler using the j[th] fuel type during period t and l[th] demand). Linearization of this term can be achieved by an exact linearization method.

In order to achieve linearity, the following equation must be reformulated.

$$\sum_{i \in F} \sum_{j} \sum_{k} \sum_{l} \sum_{t} Q_i (CO2)_{ij}\, \varepsilon_{ikt}\, E_{ijtl}^{F}\, z_{ijkt}\, P_{lt} \qquad (1)$$

The reformulation of this equation involves the introduction of a new continuous variable and several auxiliary constraints. The newly defined continuous variable $\alpha_{ijtl}$ is introduced into the equation and will replace the nonlinear expression.

$$\alpha_{ij\,ktl} = E_{ijtl}^{F}\, z_{ijkt} \qquad \forall i, \forall j, \forall t, \forall k, \forall l \qquad (2)$$

By substituting equation 2 into equation 1 the following equation is achieved,

$$\sum_{i \in F} \sum_{j} \sum_{k} \sum_{l} \sum_{t} Q_i (CO2)_{ij}\, \varepsilon_{ikt}\, \alpha_{ijktl}\, P_{lt} \qquad (3)$$

In order to insure that this reformulation will yield the same results as its non-linear counterpart, additional constraints must be defined. The constraints proposed are as follows:

$$0 \leq \alpha_{ijtl} \leq C_{ij}^{F^{max}} \qquad \forall i, \forall j, \forall t, \forall l \qquad (4)$$

$$E_{ijtl}{}^{F} - C_{ij}^{F^{max}} (1 - z_{ijkt}) \leq \alpha_{ijtl} \leq C_{ij}^{F^{max}}\, z_{ijkt} \qquad \forall i, \forall j, \forall t, \forall k, \forall l \qquad (5)$$

By introducing the new formulation for CCS cost presented in equation 3 into the objective function the MINLP is reduced to a MILP. The linearized objective function is given as:

$$
\begin{aligned}
\min\ f(i,j,k,l,t) = {} & \underbrace{\sum_{i\in F}\sum_{j}\sum_{t} F_{ijt}^{F} C_{ij}^{F} x_{ijt} + \sum_{i\in NF}\sum_{t} F_{it}^{NF} C_{i}^{NF} y_{it}^{NF}}_{Fixed\ O\&M\ \mathrm{cost}\ of\ existing\ power\ plants} + \underbrace{\sum_{i\in F}\sum_{j}\sum_{l}\sum_{t} V_{ijt}^{F} E_{ijlt}^{F} P_{lt} + \sum_{i\in NF}\sum_{l}\sum_{t} V_{it}^{NF} E_{ilt}^{NF} P_{lt}}_{Variable\ O\&M\ \mathrm{cost}\ of\ existing\ power\ plants} + \\
& \underbrace{\sum_{i\in F}\sum_{j}\sum_{l}\sum_{t} U_{jt} G_{ij}^{F} E_{ijlt}^{F} P_{lt}}_{Fuel\ \mathrm{cost}\ for\ fossil\ fuel\ plants} + \underbrace{\sum_{i\in F}\sum_{t} R_{it} h_{it}}_{\substack{retrofit\ \mathrm{cost}\ for \\ fuel\ switching}} + \underbrace{\sum_{i\in P^{new}}\sum_{t} S_{it}^{new} C_{i}^{new} n_{it}}_{\substack{capital\ \mathrm{cost}\ for\ new \\ power\ plant}} + \underbrace{\sum_{i\in P^{new}}\sum_{t} F_{it}^{new} C_{i}^{new} y_{it}^{new}}_{\substack{Fixed\ O\&M\ \mathrm{cost}\ of\ new \\ power\ plant}} + \\
& \underbrace{\sum_{i\in P^{new}}\sum_{l}\sum_{t} V_{it}^{new} E_{ilt}^{new} P_{lt}}_{\substack{Variable\ O\&M\ \mathrm{cost}\ of\ new \\ power\ plant}} + \underbrace{\sum_{i\in P^{new}}\sum_{l}\sum_{t} U_{it} G_{i}^{new} E_{ilt}^{new} P_{lt}}_{\substack{Fuel\ \mathrm{cost}\ for\ new \\ power\ plant}} + \underbrace{\sum_{t} (Cre)_t (CCost)_t}_{\substack{Cost\ of\ purchasing\ CO2 \\ emission\ credits}} + \\
& \underbrace{\sum_{i\in F}\sum_{j}\sum_{k}\sum_{l}\sum_{t} Q_i (CO2)_{ij}\, \varepsilon_{ikt} \alpha_{ijktl} P_{lt}}_{\substack{Carbon\ capture\ and\ storage\ \mathrm{cost} \\ for\ existing\ power\ plants}} + \underbrace{\sum_{i\in P^{new-cap}}\sum_{l}\sum_{t} Q_i (CO2)_i\, \varepsilon_{ikt} E_{ilt}^{new} P_{lt}}_{\substack{Carbon\ capture\ and\ storage\ \mathrm{cost} \\ for\ new\ power\ plants}}
\end{aligned}
$$

## 3.3 Model Constraints

The objection function that is discussed in Section 3.2 is subject to the following constraints.

**Annual electricity demand**

The annual electricity generated from the entire fleet minus the supplemental energy required for potential carbon capture processes ($E_{ikt}$) must be greater or equal to the annual electricity demand.

$$\sum_{i\epsilon F}\sum_{j} E_{ijtl}^{F}\, P_{lt} + \sum_{i\epsilon NF} E_{ilt}^{NF} P_{lt} + \sum_{i\epsilon\, P^{new}} E_{ilt}^{new}\, P_{lt} - \sum_{i\epsilon\, F^{c}}\sum_{k} E_{ikt} \geq D_{tl} \qquad \forall t, \forall l \qquad (6)$$

Taking into account potential energy savings due to conservation and demand management (CDM) strategies, equation 6 becomes;

$$\sum_{i\epsilon F}\sum_{j} E_{ijtl}^{F}\, P_{lt} + \sum_{i\epsilon NF} E_{itl}^{NF} P_{lt} + \sum_{i\epsilon\, P^{new}} E_{itl}^{new}\, P_{lt} - \sum_{i\epsilon\, F^{c}}\sum_{k} E_{ikt} \geq D_{tl} - B_{tl} \qquad \forall t, \forall l \qquad (7)$$

where, $B_{tl}$ is the forecasted annual energy savings (MWh) due to CDM strategies.

The energy constraint in equation 7 is enhanced further by considering the potential electricity losses incurred during the stages of transmission and distribution. Although the electricity losses in the transmission and distribution system are nonlinear with transmitted power (Scherer, 1978), an approximation could be achieved by factorizing the power received with the dispatched power. Taking into account transmission losses, equation 7 becomes;

$$(1-\rho)\left(\sum_{i\epsilon F}\sum_{j} E_{ijtl}^{F}\, P_{lt} + \sum_{i\epsilon NF} E_{itl}^{NF} P_{lt} + \sum_{i\epsilon\, P^{new}} E_{itl}^{new}\, P_{lt} - \sum_{i\epsilon\, F^{c}}\sum_{k} E_{ikt}\right) \geq D_{tl} - B_{tl} \qquad \forall t, \forall l \qquad (8)$$

where $\rho$ represents a factor for transmission and distribution losses.

**Capacity constraint for existing power stations**

In terms of the capacity allocation, the net power capacity (MW) of any power station cannot be exceeded. The maximum capacity constraints for existing fossil fuel and non-fossil fuel power plants are expressed in equations 9 and 10 respectively.

$$\sum_{l} E_{ijlt}^{F} \leq C_{ij}^{F^{max}} x_{ijt} \qquad \forall i \epsilon F, \forall t, \forall j \qquad (9)$$

$$\sum_{l} E_{ilt}^{NF} \leq C_{i}^{NF^{max}} y_{it}^{NF} \qquad \forall i \epsilon NF, \forall t \qquad (10)$$

**Construction lead time and capacity constraint for new power stations**

The multi-period nature of the planning model requires the consideration of construction lead time for new power stations, which differs depending on the type of generating technology considered. For new power stations, no power can be supplied to the grid unless the construction of the new power plant has been completed. To achieve this, equation 11 has been formulated to insure that during the construction phase of a new power plant, no electricity generating capacity is available. Furthermore, the constraint in equation 11 also functions as a capacity constraint in which the net power capacity limit of a new power plant cannot be exceeded.

$$E_{it'}^{new} \leq C_{i}^{max} (1 - n_{it}) \qquad \forall i \epsilon P^{new}, \forall t, \forall t' = 1, \ldots, [t + (\beta_i - 1)] \qquad (11)$$

The binary variable $n_{it}$ determines whether power plant i should start construction during year t. Since the start of a construction project occurs only once for a given power plant i, the value of $n_{it}$ must be less or equal 1 for the sum of all time period t (equation 12). The parameter $\beta_i$ represents the construction lead time for power station i.

$$\sum_{t} n_{it} \leq 1 \qquad \forall i \epsilon P^{new} \qquad (12)$$

A relationship between the binary variables $n_{it}$ and $y_{it}^{new}$ can be attained by formulating equation 13. This equation ensures that if construction of a new power plant i occurs during year t, the plant is operational for all time periods $t + \beta_i$.

$$(T-t) - \sum_{t=(t+\beta_i)}^{T} y_{it}^{new} + n_{it} \leq \beta_i \qquad \forall i \epsilon P^{new}, \quad \forall t = 1, \dots, (T-\beta_i) \tag{13}$$

**An alternative method for the formulation of construction lead time and capacity constraint of new power stations: The Matrix Method**

An alternative approach that can be utilized in order to incorporate construction lead time into the model involves the use of a three indices matrix which restricts the maximum power output of a given power station. Each row in the matrix corresponds to a specific year of construction and each column refers to a "regular" year. The non-zero values in the matrix specify the maximum capacity of the power station. A sample matrix for a hypothetical power plant $P_1$ is illustrated in Figure 18.

$$\begin{array}{cc} & \begin{array}{ccccc} t_1 & t_2 & t_3 & t_4 & t_5 \end{array} \\ \begin{array}{c} P_1\ t_1 \\ P_1\ t_2 \\ P_1\ t_3 \\ P_1\ t_4 \\ P_1\ t_5 \end{array} & \begin{bmatrix} 0 & 0 & 20 & 20 & 20 \\ 0 & 0 & 0 & 20 & 20 \\ 0 & 0 & 0 & 0 & 20 \\ 0 & 0 & 0 & 0 & 0 \\ 0 & 0 & 0 & 0 & 0 \end{bmatrix} \end{array}$$

**Figure 18 -** Sample matrix used in the construction lead time constraint. Each row in the matrix corresponds to a year during which construction would have commenced. The non-zero values in the matrix specify the maximum capacity of power plant $P_1$.

The above matrix can be used in conjunction with the binary variable $y_{it_c}$, which specifies the year in which construction should commence, in order to constrain the model from generating power from a power plant that has not yet been constructed. Equations 14 and 15 may be used as alternative to the mathematical constraints formulated in equation 11 and 12.

$$E_{it}^{new} \leq \sum_{t_c} y_{it_c} K_{it_c t} \qquad \forall i \epsilon P^{new}, \forall t \tag{14}$$

where $K_{it_c t}$ represents a three indices matrix.

$$\sum_{t_c} y_{it_c} \leq 1 \qquad \forall i \epsilon P^{new} \qquad (15)$$

In order to illustrate the concept that is presented in equation 14 and 15, consider the following example;

A time horizon of 5 time periods is considered in which the construction of a new coal power plant, $P_1$, should commence during time period 2. Furthermore, the time required to finish the construction of the new power plant is specified to be 2 time periods. Since the construction of $P_1$ starts in period 2 and it takes two periods to finish construction, power plant $P_1$ should not be able to supply power to the grid until time period 4. The sample problem is illustrated in Figure 19.

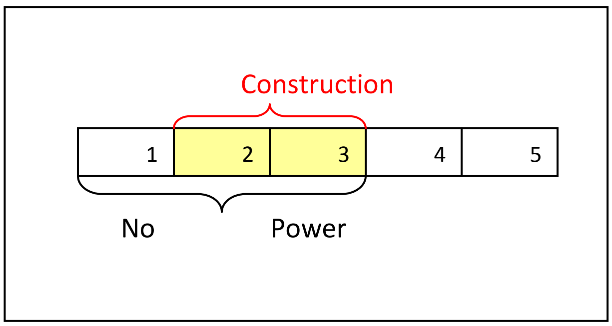



**Figure 19 –** Graphical representation of sample problem. Power plant P1 starts construction during period 2 and construction is not completed until period 3.

Given that the construction of the new power plant has been determined to start during period 2, the value for binary variable $y_{it_c}$ for power station i=1 during $t_c$ = 2, is 1 (i.e. $y_{1,2}$ = 1) and zero for all other time periods.

Based on equation 14 and the matrix in Figure 18, the energy capacity for power plant $P_1$ during time periods 1 through 5 will be;

$$E_{11}^{new} \leq 0$$
$$E_{12}^{new} \leq 0$$
$$E_{13}^{new} \leq 0$$
$$E_{14}^{new} \leq 20$$
$$E_{15}^{new} \leq 20$$

There are several advantages in using equation 14 and 15, rather than the equations presented in 11 and 12. The first advantage stems from the fact that fewer binary variables need to be defined and calculated in the method presented by 14 and 15. Secondly, the formulation in 11 and 12 generate a large number of equations which significantly impacts the computational time. Lastly, the methodology presented in equation 14 and 15 is easier to program into the GAMS optimization package.

**Capacity constraint on capture process**

The operation of any capture process requires the use of energy, either from the plant itself or from the grid. Equation 16 is formulated in order to ensure that the energy required for the k$^{th}$ carbon capture process is zero when no capture process is assigned to the i$^{th}$ coal-fired boiler. The parameter $E_k^{max}$ represents the maximum supplementary energy required for the k$^{th}$ carbon capture process.

$$E_{ikt} \leq z_{ikt} E_k^{max} \qquad \forall i \epsilon F^c, \forall k, \forall t \qquad (16)$$

**Fuel-selection and power plant shutdown**

Given that the model considers the option of fuel-switching existing coal-fired boilers with a less carbon intensive fuel, such as natural gas, a constraint must be formulated in order to restrict the use of two different fuel types on the same boiler. To achieve this goal, equation 17 has been formulated. The binary variable $x_{ijt}$ represents the fuel section (coal or natural gas) for the i$^{th}$ fossil fuel boiler during time period t and could have a value of zero if the i$^{th}$ boiler is shut-down.

$$\sum_j x_{ijt} \leq 1 \qquad \forall i \epsilon F, \forall t \qquad (17)$$

The binary variables $x_{ijt}$ and $h_{it}$ (decision whether to fuel-switch coal power plant i during time t) can be related by formulating the mathematical relation presented in equation 18.

$$(T - t + 1) - \sum_{t=t}^{T} x_{ijt} + h_{it} \geq 1 \qquad \forall t, \forall i \epsilon F, \forall j \epsilon ng \qquad (18)$$

Since fuel-switching of a coal power boiler i can occur only once during the time horizon T, the constraint in equation 19 must be included.

$$\sum_{t} h_{it} \leq 1 \qquad \forall i \epsilon F \qquad (19)$$

**Selection of $CO_2$ capture process**

In terms of $CO_2$ capture process selection for a given boiler, a capture process can only be retrofitted if the boiler is operational. Equation 20 insures that if an existing coal-fired boiler is shutdown, no $CO_2$ capture process can be put online.

$$\sum_{k} z_{ikt} \leq \sum_{j} x_{ijt} \qquad \forall i \epsilon F^c, \forall t \qquad (20)$$

Furthermore, only one type carbon capture technology can be used for a given boiler i during a time period t. The constraint formulated in equation 21 can be used to prevent the use of two carbon capture technologies on the same boiler.

$$\sum_{k} z_{ikt} \leq 1 \qquad \forall i \epsilon F^c, \forall t \qquad (21)$$

**Carbon dioxide emission constraint**

The annual $CO_2$ emissions produced as a result of electricity generation are limited by the constraint formulated in equation 22. This constraint specifies that the annual $CO_2$ emissions emitted by all existing and newly constructed boilers must be less than or equal to the specified annual $CO_2$ target. It is assumed that the only power plants that generate $CO_2$ emissions are those which use fossil fuel. Power stations that utilize non-fossil fuel, such as nuclear power plants, are assumed to have no $CO_2$ emissions and therefore are not included in equation 22.

The $CO_2$ constraint presented in equation 22 also considers the potential of $CO_2$ reduction by means of carbon credits. The $CO_2$ emitted by the entire fleet for a particular year may be reduced by the purchase of $CO_2$ credits for that year.

$$\sum_{i \epsilon F^c} \sum_{l} \left[ \left( \sum_{j} CO2_{ij}^{F} E_{ijt}^{F} P_{lt} \right) \left( 1 - \sum_{k} \varepsilon_{ikt} z_{ikt} \right) \right] + \sum_{i \epsilon P^{new}} \sum_{l} CO2_{i}^{new} E_{itl}^{new} P_{lt} - Cre_t \leq CLimit_t \qquad \forall t \qquad (22)$$

Although the constraint discussed above only pertains to $CO_2$ emissions, similar constraints can be formulated for other emissions, such as $SO_2$ and NOx, by substituting the corresponding emission coefficients and specified annual limits. Incorporating these constraints would allow the model to consider multiple pollutants and allow the emissions of these pollutants to be controlled. The drawback of including additional emission constraints within the model is that it increases the size of the model significantly and from a computational point of view would make the model difficult to solve. Therefore, the model presented in this thesis will only constrain the annual $CO_2$ emissions and will not limit the emissions of any other pollutants.

## *3.4 GAMS Model Statistics and Logic*

The model described in Sections 3.1-3.3 was programmed and implemented in the GAMS optimization package. The model was solved using the ILOG CPLEX 10.1 solver, which uses a branch and cut algorithm in order to solve complex problems. The CPLEX solver was chosen based on its advance optimization algorithm structure which allows it to solve large and complex MILP problems, such as the one presented in this thesis, with relatively high performance.

The programmed GAMS model was executed on an AMD Athlon 2.59 GHz, 2 GB RAM computer. Once executed, GAMS was able to find an optimal solution after a runtime of approximately 9 hours. The GAMS model statistics is presented in Table 7.

**Table 7 –** GAMS model statistics outlining block of equations, blocks of variables, non-zero elements, number of single equations, number of single variables and discrete variables.

| | | | |
|---|---|---|---|
| BLOCKS OF EQUATIONS | 63 | SINGLE EQUATIONS | 14,903 |
| BLOCKS OF VARIABLES | 37 | SINGLE VARIABLES | 11,476 |
| NON ZERO ELEMENTS | 82,119 | DISCRETE VARIABLES | 2,595 |

The only GAMS/CPLEX option used to solve the problem was the “Probe = Full” function available in CPLEX 10.1. This function allows an initial deep probe of the problem before any iteration is performed in order to determine the best strategy to solve the problem. Although this function may initially be very time consuming, it can sometimes significantly reduce the overall computational time of the problem.

Several other GAMS/CPLEX options were initially considered, but no significant performance or computational time improvements were noticed. The most effective strategy found to improve the overall performance and reduce the computational time of the problem was to reformulate the problem. Two formulations of the same model were found to yield dramatically different results in terms of performance and solving time.

In order to successfully run the model, several parameters, such as energy demand and power plant specifications, must be specified by the user. The parameters required by the model are retrieved via a GAMS add-on tool called xls2gams. This software tool enables GAMS to retrieve data from a specified Excel file and use the data as input parameters to the model. A detailed discussion of all the parameters needed to run the model is presented in Section 4.2.

Once all the parameters are retrieved by the xls2gams add-on tool, the model will attempt to solve the problem using the CPLEX 10.1 solver. The output of the model is exported to a Microsoft Excel file where it is automatically formatted into tables and figures. In addition to the Excel Output file, GAMS also generates an output file which contains raw data results and specific model statistics.

The logic for the model is shown in Figure 20.

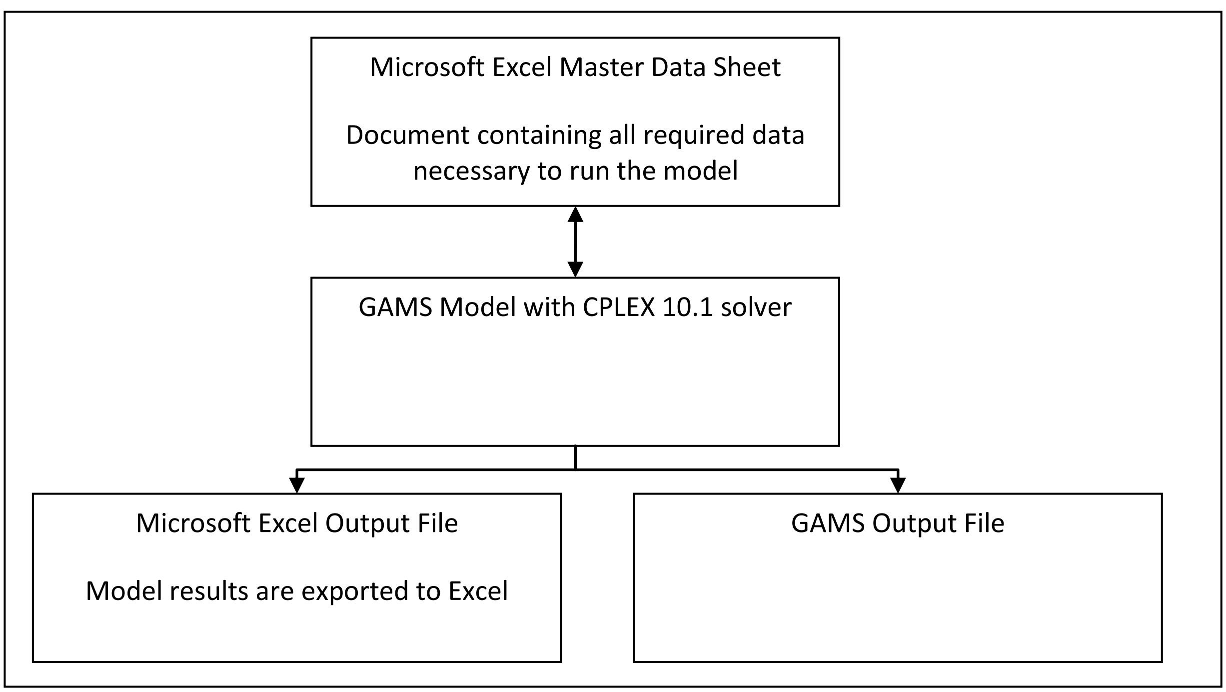



**Figure 20 –** Logic for the optimization model.

# Chapter 4

## 4.1 Description of Case Studies

The sections that follow outline two case studies that were implemented using the model developed in Chapter 3. The two case studies presented were selected in order to examine the economical and structural impact on Ontario's electricity sector when forced to comply with a given $CO_2$ emission limit. The emission limit specified is based on the Kyoto target of 6% below 1990 levels. Each case study is based on a 14 year time horizon, starting in 2006 and ending in 2020.

The two case studies examined are:

- **Case Study 1:** Presents a base case scenario in which no $CO_2$ emission limits are imposed on Ontario's electricity sector.
- **Case Study 2:** Presents a future scenario in which $CO_2$ emissions from the entire fleet must be 6% below 1990 levels after the year 2011. To achieve this, annual $CO_2$ emissions from the entire fleet must be less than 20 Mt per year after the year 2011.

In order to address future electricity demand several supply sources are considered in the case studies. The technologies that are considered include nuclear, natural gas, coal, hydroelectric, pulverized coal combustion (PC), integrated gasification combined cycle (IGCC), and natural gas combined cycle (NGCC) power plants. Although additional power plant technologies exist, the scope of the case studies discussed in this thesis only considers the above mentioned technologies as possible supply candidates.

As discussed in Chapter 3, the optimization model takes into account several distinctive characteristics of each supply technology, such as economic, environmental, and operational specifications, and determines the optimal mix of supply sources needed to satisfy each case study. The economic, environmental, and operational parameters for each supply technology are presented in Section 4.2.

The results of the case studies are presented in Sections 4.5 and 4.6. A comparative analysis of the two case studies is presented in Section 4.7.

## 4.2 Data for Case Studies

This section provides several of the required input data parameters necessary to implement the model developed in Chapter 3.

### 4.2.1 Existing Power Plants

**Fossil-Fueled Power Plants**

Ontario currently operates four coal-fired power plants with a combined capacity of approximately 6,285 MW. The four coal power plants currently in operation are Lambton, Nanticoke, Atitokan, and Thunder Bay. In addition to the four coal-fired power plants, there is a duel fueled oil and natural gas power plant referred to as the Lennox generating station.

The economic and operational parameters for existing coal and NG and oil power plants in Ontario are presented in Table 8. This table also presents the cost associated with fuel-switching an existing coal-power plant to natural gas. The variable and fixed operating and maintenance (O&M) cost for the coal power plants were obtained from Ontario Ministry of Energy (2005). All other parameters were attained from Hashim (2006).

**Table 8 –** Economic and operational parameters of existing coal-power plants and cost associated with fuel-switching to natural gas. All costs are expressed in terms of 2005 Canadian dollars.

| Power Plant | Gross Capacity (MW) | Non-Fuel Variable O&M Cost ($/MWh) | | Fixed O&M Cost ($/MW) | | Capacity Factor (%) | Retrofit Cost ($/MW) | Heat Rate (GJ/MWh) | | CO2 Emissions ( tCO2 / MWh) | | Cost of CCS ($/t CO2) | Elec. req. for CCS (MWh/t CO2) | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | coal | ng | coal | ng | | | coal | ng | coal | ng | | coal | ng |
| **Lambton** | 1948 | 2.45 | 0 | 36804 | 15970 | 0.75 | 23676.79 | 9.84 | 6.77 | 0.9278 | 0.5631 | 55.83579 | 0.317 | 0.356 |
| **Nanticoke** | 3820 | 2.25 | 0 | 32715 | 15970 | 0.75 | 23676.79 | 9.88 | 6.77 | 0.93 | 0.558 | 55.38001 | 0.317 | 0.356 |
| **Atitokan** | 211 | 5.11 | 0 | 74631 | 20994 | 0.75 | 23676.79 | 9.82 | 6.77 | 1.023 | 0.6138 | 212.7123 | 0.317 | 0.356 |
| **Lennox** | 2100 | 0 | 0 | n/a | 15970 | 0.75 | n/a | 7.82 | 6.77 | 0.651 | 0.651 | n/a | 0.356 | 0.356 |
| **Thunder Bay** | 306 | 5.11 | 0 | 74631 | 20994 | 0.75 | 23676.79 | 11.7 | 6.77 | 1.023 | 0.6138 | 216.2164 | 0.317 | 0.356 |

**Natural Gas Power Plants**

In Ontario, there are 60 natural gas power plants in operation, but only 20 of these power plants are connected to Ontario's electricity grid. The case studies discussed in this thesis will only takes into account the natural gas power stations which are connected to the grid. The operational and economic parameters for the existing natural gas power plants are presented in Table 9. The data outlined in Table 9 was obtained from Ontario Power Authority (2005).

**Table 9 –** Operational and economic parameters for existing natural gas power plants. All costs are expressed in terms of 2005 Canadian dollars (Ontario Power Authority, 2005).

| Technology | Non-Fuel Variable O&M Cost ($/MWh) | Fixed O&M Cost ($/MW) | Capacity Factor (%) | CO2 Emissions ( tonne CO2 / MWh) |
|---|---|---|---|---|
| **Single Cycle** | 3.42 | 5310 | 0.85 | 0.408 |
| **Combined Cycle** | 2.64 | 16020 | 0.85 | 0.290 |
| **Cogeneration** | 2.74 | 29880 | 0.85 | 0.290 |

**Nuclear Power Plants**

As mentioned in Section 2.4.1, most of the existing nuclear units in Ontario will reach the end of their service life by 2018. Consequently, Ontario's nuclear units will need to be decommissioned, refurbished, or replaced within the time horizon of the case studies presented in this thesis. The end-of-service dates for all 20 nuclear units in Ontario are presented in Table 2.

The refurbishment of a nuclear unit involves a significant amount of capital investment. The estimated refurbishment costs for Ontario's nuclear power units are presented in Table 10. The case studies discussed in this thesis will use the midpoint estimate when considering refurbishment cost of nuclear units (e.g., $3.5 billion for Pickering B). Furthermore, it is assumed that the lead-time for the refurbishment of a single nuclear unit will be approximately two years. During the refurbishment process, the unit being refurbished will be shutdown and consequently no electricity can be produced from that unit. The estimates for refurbishment costs were attained from Winfield et al. (2004).

**Table 10 –** Estimated refurbishment cost for nuclear units in Ontario. All costs are expressed in terms of 2005 Canadian dollars (Winfield et al., 2004).

| Station | Cost Range |
|---|---|
| **Bruce 3 & 4** | $720 million |
| **Bruce 1 & 2** | $1.5 to $2.5 million |
| **Bruce B (5-8)** | $3 to $4 billion |
| **Pickering A (1-4)** | $3 to $4 billion |
| **Pickering B (5-8)** | $3 to $4 billion |
| **Darlington (1-4)** | $3 to $4 billion |
| **Total** | $14.2 to $19.2 billion |

The decommissioning of nuclear units is a very complex and cost intensive process. The work involved in a nuclear decommissioning project include the dismantling of the plant structure, decontamination of equipment, site remediation, and long term storage of nuclear waste. The estimated cost of decommissioning all 20 nuclear units in Ontario is 7.4 billion (Winfield et al., 2004).

The case studies presented in this thesis assume that all the nuclear power units in Ontario will be refurbished before the end-of-service year outlined in Table 2. The capacity profile for all nuclear units is shown in Table 11.

**Table 11 –** Capacity (MW) profile for all 20 nuclear units in Ontario from 2006-2020. The shaded area in the table represent the periods in which the unit was shut-down in order to undergo refurbishment.

| | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Pickering 1 | 515 | 515 | 515 | 515 | 515 | 515 | 515 | 515 | 515 | 515 | 515 | 515 | 515 | 515 | 515 |
| Pickering 2 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Pickering 3 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Pickering 4 | 515 | 515 | 515 | 515 | 515 | 515 | 515 | 515 | 515 | 515 | 515 | 0 | 0 | 515 | 515 |
| PICKERING A | 1030 | 1030 | 1030 | 1030 | 1030 | 1030 | 1030 | 1030 | 1030 | 1030 | 1030 | 515 | 515 | 1030 | 1030 |
| Pickering 5 | 516 | 516 | 516 | 0 | 0 | 516 | 516 | 516 | 516 | 516 | 516 | 516 | 516 | 516 | 516 |
| Pickering 6 | 516 | 516 | 516 | 516 | 0 | 0 | 516 | 516 | 516 | 516 | 516 | 516 | 516 | 516 | 516 |
| Pickering 7 | 516 | 516 | 516 | 516 | 516 | 0 | 0 | 516 | 516 | 516 | 516 | 516 | 516 | 516 | 516 |
| Pickering 8 | 516 | 516 | 516 | 516 | 516 | 516 | 0 | 0 | 516 | 516 | 516 | 516 | 516 | 516 | 516 |
| PICKERING B | 2064 | 2064 | 2064 | 1548 | 1032 | 1032 | 1032 | 1548 | 2064 | 2064 | 2064 | 2064 | 2064 | 2064 | 2064 |
| Bruce 1 | 0 | 0 | 0 | 750 | 750 | 750 | 750 | 750 | 750 | 750 | 750 | 750 | 750 | 750 | 750 |
| Bruce 2 | 0 | 0 | 0 | 0 | 750 | 750 | 750 | 750 | 750 | 750 | 750 | 750 | 750 | 750 | 750 |
| Bruce 3 | 750 | 750 | 750 | 750 | 750 | 750 | 750 | 0 | 0 | 750 | 750 | 750 | 750 | 750 | 750 |
| Bruce 4 | 750 | 750 | 750 | 750 | 750 | 750 | 750 | 750 | 750 | 750 | 750 | 0 | 0 | 750 | 750 |
| BRUCE A | 1500 | 1500 | 1500 | 2250 | 3000 | 3000 | 3000 | 2250 | 2250 | 3000 | 3000 | 2250 | 2250 | 3000 | 3000 |
| Bruce 5 | 785 | 785 | 785 | 785 | 785 | 0 | 0 | 0 | 785 | 785 | 785 | 785 | 785 | 785 | 785 |
| Bruce 6 | 820 | 820 | 820 | 820 | 0 | 0 | 820 | 820 | 820 | 820 | 820 | 820 | 820 | 820 | 820 |
| Bruce 8 | 785 | 785 | 785 | 785 | 785 | 785 | 0 | 0 | 785 | 785 | 785 | 785 | 785 | 785 | 785 |
| Bruce 7 | 785 | 785 | 785 | 785 | 785 | 785 | 785 | 0 | 0 | 785 | 785 | 785 | 785 | 785 | 785 |
| BRUCE B | 3175 | 3175 | 3175 | 3175 | 2355 | 1570 | 1605 | 820 | 2390 | 3175 | 3175 | 3175 | 3175 | 3175 | 3175 |
| Darlington 1 | 881 | 881 | 881 | 881 | 881 | 881 | 881 | 881 | 881 | 881 | 881 | 881 | 0 | 0 | 881 |
| Darlington 2 | 881 | 881 | 881 | 881 | 881 | 881 | 881 | 881 | 881 | 881 | 0 | 0 | 881 | 881 | 881 |
| Darlington 3 | 881 | 881 | 881 | 881 | 881 | 881 | 881 | 881 | 881 | 881 | 881 | 881 | 881 | 0 | 0 |
| Darlington 4 | 881 | 881 | 881 | 881 | 881 | 881 | 881 | 881 | 881 | 881 | 881 | 881 | 881 | 0 | 0 |
| DARLINGTON | 3524 | 3524 | 3524 | 3524 | 3524 | 3524 | 3524 | 3524 | 3524 | 3524 | 2643 | 2643 | 2643 | 881 | 1762 |

The operational and economic parameters for Ontario's existing nuclear units are presented in Table 12. The data outlined in Table 12 was obtained from Ontario Power Authority (2005).

**Table 12 -** Operational and economic parameters for existing nuclear units. All costs are expressed in terms of 2005 Canadian dollars (Ontario Power Authority, 2005).

| Station | Variable O&M Cost ($/MWh) | Fixed O&M Cost ($/MW) | Capacity Factor |
|---|---|---|---|
| **Bruce A** | 1.42 | 105720 | 0.9 |
| **Bruce B** | 1.42 | 105720 | 0.9 |
| **Darlington** | 1.42 | 105720 | 0.9 |
| **Pickering A** | 1.42 | 105720 | 0.9 |
| **Pickering B** | 1.42 | 105720 | 0.9 |

**Hydroelectric**

Hydroelectric power plays a very important role in Ontario's current energy mix. Approximately 26% of Ontario's installed capacity is composed of hydroelectric power. There are currently 108 hydroelectric stations within Ontario, but only 58 stations are directly connected to the electricity grid (Ontario Ministry of Energy, 2007).

Ontario's existing hydroelectric stations provide electricity for both base-load and peak-load demand. The total hydroelectric capacity available to serve base-load demand in Ontario is approximately 3,424 MW. The hydroelectric capacity to meet intermediate and peak-load demand is approximately 3,299 MW (Atomic Energy of Canada Limited, 2005). The hydroelectric stations that are designated for base-load electricity production are the Beck and Decew hydro stations in Niagara, and the R.H. Saunders hydro station near Cornwal (Ontario Ministry of Environment, 2006).

The operational and economic parameters for the existing hydroelectric stations are presented in Table 13. The data outlined in Table 13 was obtained from Ontario Power Authority (2005).

**Table 13 -** Operational and economic parameters for existing hydroelectric stations in Ontario. All costs are expressed in terms of 2005 Canadian dollars (Ontario Power Authority, 2005).

| | Variable O&M Cost ($/MWh) | Fixed O&M Cost ($/MW) | $CO_2$ Emissions (tonne $CO_2$/MWh) |
|---|---|---|---|
| **Hydroelectric** | 0 | 40830 | 0 |

### *4.2.2 New Power Plants*

In order to meet future electricity demand, new power plants will need to be built. The case studies discussed in this thesis will examine the use of the following supply sources to meet future demand:

- Nuclear
- Pulverized coal combustion (PC)
- Integrated Gasification Combined Cycle (IGCC)
- Natural Gas Combined Cycle (NGCC)
- Long Term Out-Of-Province Hydroelectric Imports

Although additional supply sources exist, the scope of the studies presented in this thesis only considers the above mentioned technologies as possible candidates.

The outlined supply sources all have distinctive characteristics and may differ greatly based on environmental, economical and operational parameters. Some technologies offer lower capital and operating cost at high emission rates, while other supply options have higher associated costs but lower environmental impacts. In terms of capital cost, there are economies of scales that favor construction of large power stations over smaller ones. The capital and operational cost for building one large unit is often lower then if two smaller units, with the same total capacity, were built.

The economical and operational parameters for the PC, IGCC, and NGCC power units used in the case studies are presented in Table 14, Table 15, and Table 16, respectively. The data outlined in Table 14 – Table 16 were obtained from the Integrated Environmental Control Model (IECM) developed by Carnegie Mellon University and the Department of Engineering and Public Policy. The IECM is a computer modeling tool that performs a complete performance, emissions, and cost assessment of various fossil-fueled power plants of different capacity and operational specifications. The estimates for project cash-flow during construction were obtained from Ayres, MacRae, and Stogran (2004). The costs of CCS presented in Table 14 -Table 16 were obtained from Hashim (2006). For the power stations that have an integrated CCS system, the cost associated with CCS is incorporated in the cost and operational parameters presented in Table 14 -Table 16.

The economic and operational parameters for nuclear power plants used in the case studies are presented in Table 17. The data in Table 17 were obtained from Ayres et al. (2004). The case studies presented examine two types of nuclear technologies. The first nuclear unit is a twin ACR-700 nuclear reactor with a net capacity of 1,406 MW. The second reactor is a twin CANDU 6 nuclear unit with a net capacity of 1,346 MW. The cost and operational parameters of these two nuclear units are significantly different. The capital and fixed operating costs of the twin CANDU 6 units are generally higher than that of the ACR-700 reactors. A slight advantage that CANDU 6 reactors possess is the fact that they have a significantly lower variable operating cost than its predecessor, the ACR-700.

In addition to the power plant technologies discussed above, the case studies presented in this thesis will examine the potential long-term electricity supply from out-of-province hydroelectric imports. More specifically, the case studies consider the potential use of the Ontario-Manitoba Interconnection (OMI) project as a long term electricity supply source. A description of the OMI project is presented in Section 2.2.6. The economic cost for the OMI project is outlined in Table 18. The data from Table 18 was obtained from Ontario Power Authority (2005).

**Table 14 –** Economic and operational parameters for pulverized coal (PC) power plants. This table presents data for single PC units and PC units that have been retrofitted with a MEA Carbon Capture and Storage (CCS) system. All costs are expressed in terms of 2005 Canadian dollars.

| | PC | PC | PC with CCS | PC with CCS | PC with CCS |
|---|---|---|---|---|---|
| Gross Capacity (MW) | 457.7 | 526.5 | 337.4 | 459.2 | 491.7 |
| Non-Fuel Variable O&M Cost ($/MWh) | 2.866172247 | 2.855230313 | 20.28099538 | 19.62101636 | 19.46717892 |
| Fixed O&M Cost ($/MW) | 57290.89899 | 52839.93878 | 96454.497 | 83296.71947 | 80439.44886 |
| Capital Cost ($/MW) | 1,776,943 | 1,724,854 | 3,074,431 | 2,900,407 | 2,850,685 |
| Capacity Factor (%) | 0.75 | 0.75 | 0.75 | 0.75 | 0.75 |
| Heat Rate (BTU/MWh) | 9.59801646 | 9.59485123 | 13.0196244 | 13.0090736 | 13.0090736 |
| $CO_2$ Emissions (tonne $CO_2$/MWh) | 0.875075515 | 0.874791439 | 0.118789039 | 0.118692638 | 0.11867017 |
| $NO_2$ Emissions (tonne $NO_2$/MWh) | 3.100E-05 | 3.0946E-05 | 3.1485E-05 | 3.1471E-05 | 3.1457E-05 |
| NO Emissions (tonne NO/MWh) | 0.0004 | 0.000383 | 0.000520273 | 0.000519972 | 0.000519735 |
| $SO_2$ Emissions (tonne $SO_2$/MWh) | 0.001085 | 0.001084 | 4.27E-07 | 4.27E-07 | 4.27E-07 |
| Cost of CCS ($/tonne $CO_2$) | N/A | N/A | 74.28 | 69.27 | 62.88 |
| Construction lead time (years) | 5 | 5 | 5 | 5 | 5 |
| Project Cash Flow | Year 0: 3.1% (down payment)<br>Year 1: 16.1%<br>Year 2: 30.8%<br>Year 3: 34.1%<br>Year 4: 15.9% | | | | |

**Table 15 -** Economic and operational parameters for Integrated Gasification Combined Cycle (IGCC) power units. This table presents data for single IGCC units and IGCC units that have been retrofitted with a MEA Carbon Capture and Storage (CCS) system. All costs are expressed in terms of 2005 Canadian dollars.

| | IGCC | IGCC | IGCC | IGCC with CCS | IGCC with CCS | IGCC with CCS |
|---|---|---|---|---|---|---|
| Gross Capacity (MW) | 274.8 | 552.4 | 830.3 | 231.4 | 465.8 | 700.5 |
| Non-Fuel Variable O&M Cost ($/MWh) | 1.24 | 1.23713470 | 1.24402075 | 12.9655949 | 11.1619224 | 10.4532119 |
| Fixed O&M Cost ($/MW) | 97748.609 | 72521.9550 | 63476.4947 | 145,191.72 | 112,030.15 | 74,494.85 |
| Capital Cost ($/MW) | 2,377,150 | 2,217,331 | 2,140,382 | 3,562,173 | 3,327,773 | 3,327,773 |
| Capacity Factor (%) | 0.85 | 0.85 | 0.85 | 0.85 | 0.85 | 0.85 |
| Heat Rate (BTU/MWh) | 11.173243 | 11.1099388 | 11.0888373 | 13.3572484 | 13.2728424 | 13.2306394 |
| $CO_2$ Emissions (tonne $CO_2$/MWh) | 0.9860847 | 0.98092224 | 0.97896847 | 0.08997359 | 0.08939411 | 0.08915146 |
| $NO_2$ Emissions (tonne $NO_2$/MWh) | 4.3048E-06 | 4.2814E-06 | 4.2732E-06 | 5.2259E-06 | 5.1942E-06 | 5.1802E-06 |
| NO Emissions (tonne NO/MWh) | 5.33E-05 | 5.31E-05 | 5.29E-05 | 6.47653E-05 | 6.43677E-05 | 6.41958E-05 |
| $SO_2$ Emissions (tonne $SO_2$/MWh) | 8.92E-05 | 8.88E-05 | 8.86E-05 | 0.000107 | 0.0001 | 0.000106 |
| Cost of CCS ($/tonne $CO_2$) | N/A | N/A | N/A | 19.79 | 15.41 | 15.41 |
| Construction lead time (years) | 5 | 5 | 5 | 5 | 5 | 5 |
| Project Cash Flow | Year 0: 3.1% (down payment)<br>Year 1: 16.1%<br>Year 2: 30.8%<br>Year 3: 34.1%<br>Year 4: 15.9% | | | | | |

**Table 16 -** Economic and operational parameters for Natural Gas Combined Cycle (NGCC) power units. This table presents data for single NGCC units and NGCC units that have been retrofitted with a MEA Carbon Capture and Storage (CCS) system. All costs are expressed in terms of 2005 Canadian dollars.

| | NGCC | NGCC | NGCC | NGCC with CCS | NGCC with CCS | NGCC with CCS |
|---|---|---|---|---|---|---|
| Gross Capacity (MW) | 253.3 | 506.5 | 759.8 | 216.1 | 432.3 | 648.4 |
| Non-Fuel Variable O&M Cost ($/MWh) | 0 | 0 | 0 | 8.57967927 | 6.68023991 | 5.93628639 |
| Fixed O&M Cost ($/MW) | 20994.10 | 15970.730 | 14284.6016 | 39322.5348 | 29082.5243 | 27003.3712 |
| Capital Cost ($/MW) | 752,685 | 748,542 | 746,411 | 1,319,981 | 1,220,539 | 1,240,664 |
| Capacity Factor (%) | 0.85 | 0.85 | 0.85 | 0.85 | 0.85 | 0.85 |
| Heat Rate (BTU/MWh) | 7.177674 | 7.1776746 | 7.17767461 | 8.41105719 | 8.41105719 | 8.41105719 |
| $CO_2$ Emissions (tonne $CO_2$/MWh) | 0.367458 | 0.3673516 | 0.36738713 | 0.04307133 | 0.04304038 | 0.04305070 |
| $NO_2$ Emissions (tonne $NO_2$/MWh) | 4.6237E-06 | 4.6264E-06 | 4.6255E-06 | 4.0662E-06 | 4.0648E-06 | 4.0658E-06 |
| NO Emissions (tonne NO/MWh) | 5.73E-05 | 5.73E-05 | 5.73229E-05 | 6.71678E-05 | 6.71732E-05 | 6.71714E-05 |
| $SO_2$ Emissions (tonne $SO_2$/MWh) | 0 | 0 | 0 | 0 | 0 | 0 |
| Cost of CCS ($/tonne $CO_2$) | N/A | N/A | N/A | 71.53 | 46.98 | 46.98 |
| Construction lead time (years) | 3 | 3 | 3 | 3 | 3 | 3 |
| Project Cash Flow | Year 0: 0% (down payment)<br>Year 1: 50%<br>Year 2: 50% | | | | | |

**Table 17 -** Economic and operational parameters for nuclear power units. All costs are expressed in terms of 2005 Canadian dollars.

| | Twin ACR-700 | Twin CANDU 6 |
|---|---|---|
| Gross Capacity (MW) | 1506 | 1456 |
| Net Capacity (MW) | 1406 | 1346 |
| Variable O&M Cost including Fuel ($/MWh) | 4 | 2.3 |
| Fixed O&M Cost ($/MW) | 11,160.00 | 13,270.00 |
| Capital Cost ($/MW) | 2,414,170 | 3,057,050 |
| Capacity Factor (%) | 0.9 | 0.9 |
| $CO_2$ Emissions (tonne $CO_2$/MWh) | 0 | 0 |
| $NO_2$ Emissions (tonne $NO_2$/MWh) | 0 | 0 |
| NO Emissions (tonne NO/MWh) | 0 | 0 |
| $SO_2$ Emissions (tonne $SO_2$/MWh) | 0 | 0 |
| Construction lead time (years) | 8 | 8 |
| Project Cash Flow | Year 0: 3.1% (down payment)<br>Year 1: 8.0%<br>Year 2: 21.0%<br>Year 3: 27.1%<br>Year 4: 19.6%<br>Year 5: 12.0%<br>Year 6:7.2 %<br>Year 7: 5.1% | |

**Table 18 -** Economic and operational parameters for long term out-of-province hydroelectric imports. All costs are expressed in terms of 2005 Canadian dollars (Ontario Power Authority, 2005).

| | Gross Capacity (MW) | Variable O&M Cost ($/MWh) | Fixed O&M Cost ($/MW) | Capital Cost ($/MW) | $CO_2$ Emissions (tonne $CO_2$/MWh) |
|---|---|---|---|---|---|
| Long Term Out-of-Province Purchase | 1250 | 0 | 42350 | 4,550,000 | 0 |

### 4.2.3 Forecasted Data

Forecasted energy demand was obtained from the analysis generated by Chui et al. (2006). For all case studies, a conservative median energy, base-load, peak-load forecast was assumed. This forecast was discussed in Section 2.5.1 of this thesis.

The NEB fuel forecasts discussed in Sections 2.5.2.1 and 2.5.2.2 were used for the case studies presented. The assumption was made that technology advances gradually and that there is limited action on the environment in Canada (Supply Push scenario).

In terms of Conservation and Demand Management, the case studies presented in this thesis assume a conservation forecast based on programs in which financial incentives equal 50% of incremental cost of new equipment installation (EE50). Data and discussion regarding conservation initiatives are presented in Section 2.5.3.

## 4.3 Assumptions of Case Studies

The model and case studies presented in this thesis assume the following:

- The electricity generated from nuclear power units is only used for base-load demand. Nuclear units cannot be utilized for peak-demand generation due to design and safety related limitations. For this reason, it is assumed that all power generated from nuclear units will only be used to satisfy base-load demand.
- All existing nuclear units in Ontario will be refurbished before their end-of-service dates. The refurbishment cost associated with each unit is a mid-point estimate of the data presented in Table 10. The time required to refurbish a single unit is assumed to be two years (Winfield et al., 2004). During the refurbishment process, the unit being refurbished will be shutdown and consequently no electricity can be produced from that unit.
- The total hydroelectric capacity available to serve base-load demand in Ontario is approximately 3,424 MW. The hydroelectric capacity to meet intermediate and peak-load demand is approximately 3,299 MW (Atomic Energy of Canada Limited, 2005).
- No new renewable supply sources are realized within the time horizon of the case studies presented in this thesis.
- Fixed and Variable O&M costs for all power stations are assumed to remain constant over time. Although the O&M costs of power stations often increase over time, due to aging of the unit, no reliable data were found to address the increase in O&M costs over time.
- It is assumed that the technology for CCS is available and $CO_2$ sequestration within the two reservoirs in Ontario, Lake Huron and Lake Erie, can be realized.

## 4.4 Defining Power Allocation and Installed Capacity

There are two terms that are frequently used when describing electricity production and structure. The first term is "power allocation" and the second is "installed capacity". Although these two terms are related, they have very different meanings. This section attempts to clarify the meaning of these two terms.

Power allocation is defined as the amount of power (MW) that a given power plant allocates *in order to satisfy demand*. The power allocated from a power plant is further divided into base-load allocation and peak-load allocation. Similar to its root meaning, base-load allocation is the amount of power that a power plant allocates to meet base-load demand, and peak-load demand is the amount of power that a power plant allocates in order to meet peak-load demand.

Alternatively, installed capacity is defined as a power plant's electric generating capacity *when operating at full production*. It is measured in MW units. The installed capacity of a power plant does not give any indication of how much power has been assigned to meet demand.

The case studies presented in the following sections will describe the fleet-structure in terms of power allocation.

## 4.5 Case Study I: Base Case

The base case represents a scenario in which no $CO_2$ emission limits are imposed on the electricity sector. Moreover, this case study assumes that a carbon credit system or market is established in which individual power stations may purchase carbon credits at a cost. It is assumed that the technology for CCS in Ontario is available and can be implemented if needed.

This case study also assumes that the phasing-out of coal power plants is not enforced by the policy makers. The existing nuclear power units will be refurbished based upon their estimated end-of-service dates. Furthermore, the assumption is made that all new or existing nuclear power plants are only used to meet base-load demand and are not used to satisfy peak-demand. Conversely, wind power will be used for the purpose of meeting peak demand and not base load demand.

Results for Case Study I are presented in the following sub-sections.

### 4.5.1 *Fleet Structure: New construction, fuel-switching, and CCS retrofit*

Table 19 illustrates the construction of new power stations for the base case. It includes the year in which the construction of new power plants started (represented by an "X"), as well as the years during which the unit is under construction (represented by the shaded area).

**Table 19 –** Case Scenario I: Construction of new power stations. The "X" represents the year in which construction of the new generating unit started and the shaded are represents the years during which the unit is under construction. The years after the shaded areas assume the unit to be fully operational.

| | Net Capacity (MW) | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | New Power Plant Without CCS | | | | | | | | |
| **PC-31** | 526.5 | X | | | | | | | | | | | | | | |
| **NGCC-22** | 1013 | X | | | | | | | | | | | | | | |
| **NGCC-31** | 759.8 | | | X | | | | | | | | | | | | |
| **NGCC-32** | 1519.6 | | | | | X | | | | | | | | | | |
| **NGCC-23** | 1519.5 | | | | | | | | | X | | | | | | |
| **NGCC-21** | 506.5 | | | | | | | | | | | X | | | | |

From Table 19, it can be seen that for the base case, one new PC and five new NGCC power stations need to be built between 2006 and 2020. The total net capacity of all new NGCC and PC units is 5,318 MW and 526.5 MW respectively.

For this case study, the model selected to keep all existing coal, natural gas, wind, and hydroelectric power stations operational throughout the study period (2006-2020).

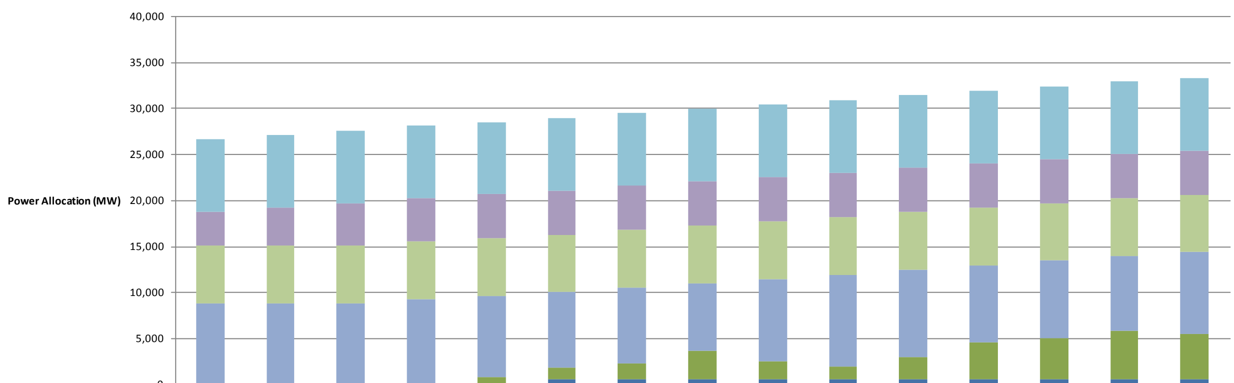
No fuel-switching was implemented on existing coal power plants by the model. The decision not to fuel-switch any of the existing coal power plants to natural gas is due to the fact that there are no $CO_2$ limits in the base case. Since no $CO_2$ limits are imposed, and operating a unit using coal as a fuel source is cheaper than using natural gas, the model selected to continue using coal as its fuel source rather than fuel-switch to natural gas.  Additionally, there is a capital cost associated with fuel-switching a coal powered station to natural gas which would not be justified in this scenario. The decision to not fuel-switch existing coal power plants will inevitably lead to higher $CO_2$ emissions if no CCS is implemented.

Even though PC power plants have lower fuel cost than NGCC's, the model chose to build five new NGCC power stations and only one new PC. This may be due to the lower capital cost of building a new NGCC unit outweighing the fuel costs associated with use of natural gas.

Since there are no $CO_2$ emission constraints in place, the model did not retrofit any of the existing coal power plants with CCS. Putting a CCS system in place requires significant capital investment which would increase the total cost without justification in this case.

## *4.5.2 Power Allocation and Electricity Production*

Total power (MW) allocated from each supply technology for the base case is presented in Figure 21**.** Total percent of power allocated to each generating technology for years 2006, 2010, 2015 and 2020 is given in Figure 22.




| | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Renewable | 7902 | 7902 | 7902 | 7902 | 7902 | 7902 | 7902 | 7902 | 7902 | 7902 | 7902 | 7902 | 7902 | 7902 | 7902 |
| Existing NG & Oil | 3615 | 4098 | 4598 | 4719 | 4814 | 4814 | 4814 | 4814 | 4814 | 4814 | 4814 | 4814 | 4814 | 4814 | 4814 |
| Coal | 6285 | 6285 | 6285 | 6285 | 6285 | 6285 | 6285 | 6285 | 6285 | 6285 | 6285 | 6285 | 6285 | 6285 | 6285 |
| Hydro Imports | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Nuclear | 8849 | 8849 | 8849 | 9144 | 8820 | 8227 | 8253 | 7364 | 8935 | 10057 | 9533 | 8430 | 8430 | 8180 | 8857 |
| NGCC + CCS | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| IGCC + CCS | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| PC + CCS | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| NGCC | 0 | 0 | 0 | 101 | 772 | 1293 | 1735 | 3107 | 2034 | 1389 | 2402 | 4009 | 4528 | 5312 | 5015 |
| IGCC | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| PC | 0 | 0 | 0 | 0 | 0 | 527 | 527 | 527 | 527 | 527 | 527 | 527 | 527 | 527 | 527 |

**Figure 21 -** Case Scenario I: Total power allocated (MW) from each supply technology.

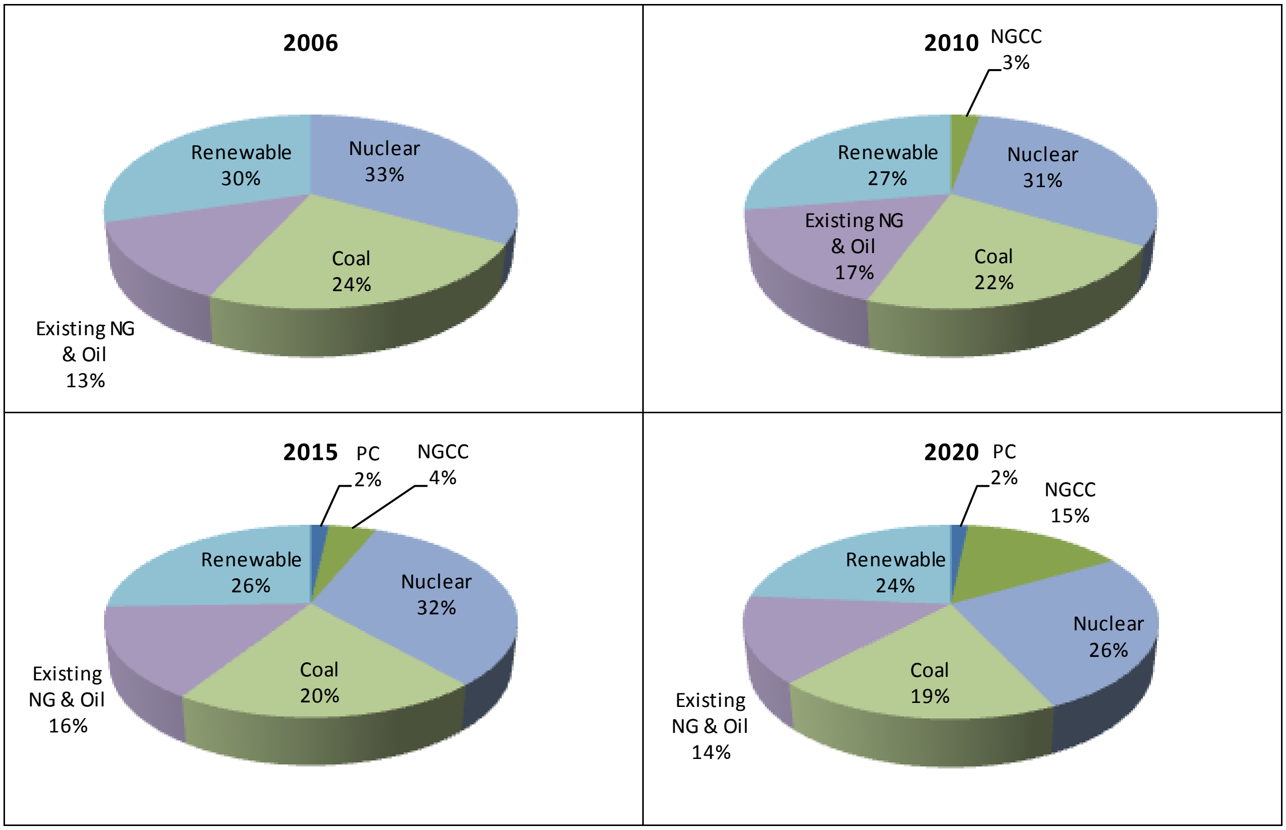



**Figure 22** - Case Scenario I: Total power allocation in terms of percentage for the years 2006, 2010, 2015 and 2020.

From Figure 21, it can be seen that the power allocated from renewable sources stays constant at 7,902 MW. The power allocated from renewable sources does not increase since no new renewable supply sources are considered in any of the case studies, as discussed in Section 4.3. Existing NG and oil allocation reaches a maximum of 4,814 MW in 2010. From this year on, the NG and oil allocation stays constant. In order for existing NG and oil power to exceed its maximum capacity, at least one of the coal power units would have to fuel-switch to natural gas. As discussed in the previous section, there is no fuel-switching in the base case.

As shown in Figure 21, power allocated from coal plants remains constant at a maximum of 6,285 MW. All coal power units are operating at maximum capacity during 2006-2020 in order to meet both peak-load and base-load demand. No long term hydroelectric imports are realized. From Figure 21, power allocated from nuclear plants ranges from 7,364 MW in year 2013 to 10,057 MW in 2015. As discussed in Section 4.2.1, during the time period studied some nuclear power plants will undergo refurbishment at certain years (for instance, Pickering 4 undergoes refurbishment during the 2017-2018 period). During this time, the units that are being refurbished cannot generate any electricity and cannot contribute to the total power allocated from nuclear plants.

No NGCC+CCS, IGCC+CCS, PC+CCS, and IGCC were constructed during the time horizon considered, and hence no power was allocated from these supply sources. From Figure 21, power allocated from NGCC ranges from 101 MW in 2009 to 5,312 MW in 2019. PC operates at a maximum capacity of 526.5 MW from the first year of operation, 2011.

From Figure 22, it can be seen that in the year 2006 13% of power is allocated from existing NG and oil, 24% from coal, 30% from renewable sources and 33% from nuclear plants in order to meet demand. By year 2010, NGCC becomes part of the total energy mix. By the year 2015, PC also contributes to the total power.

As energy demand rises over the years, the percent of power allocated from nuclear sources comprises less of the total supply mix. By 2020, percent of power allocated from nuclear sources amounts to 26% of the total mix.

Figure 23 and Figure 24 show the power (MW) allocated from each supply source to meet base-load and peak-load demands, respectively.

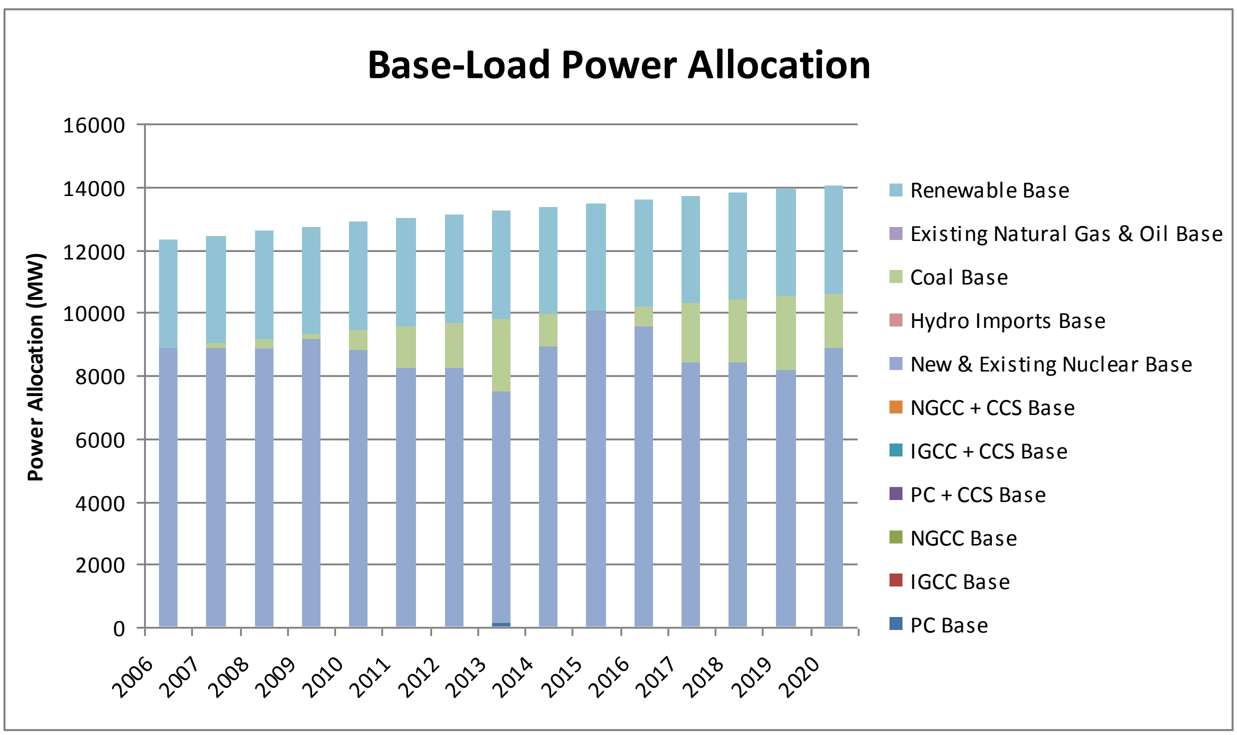



**Figure 23 –** Case Study I: Power allocated to meet base-load demand (MW).

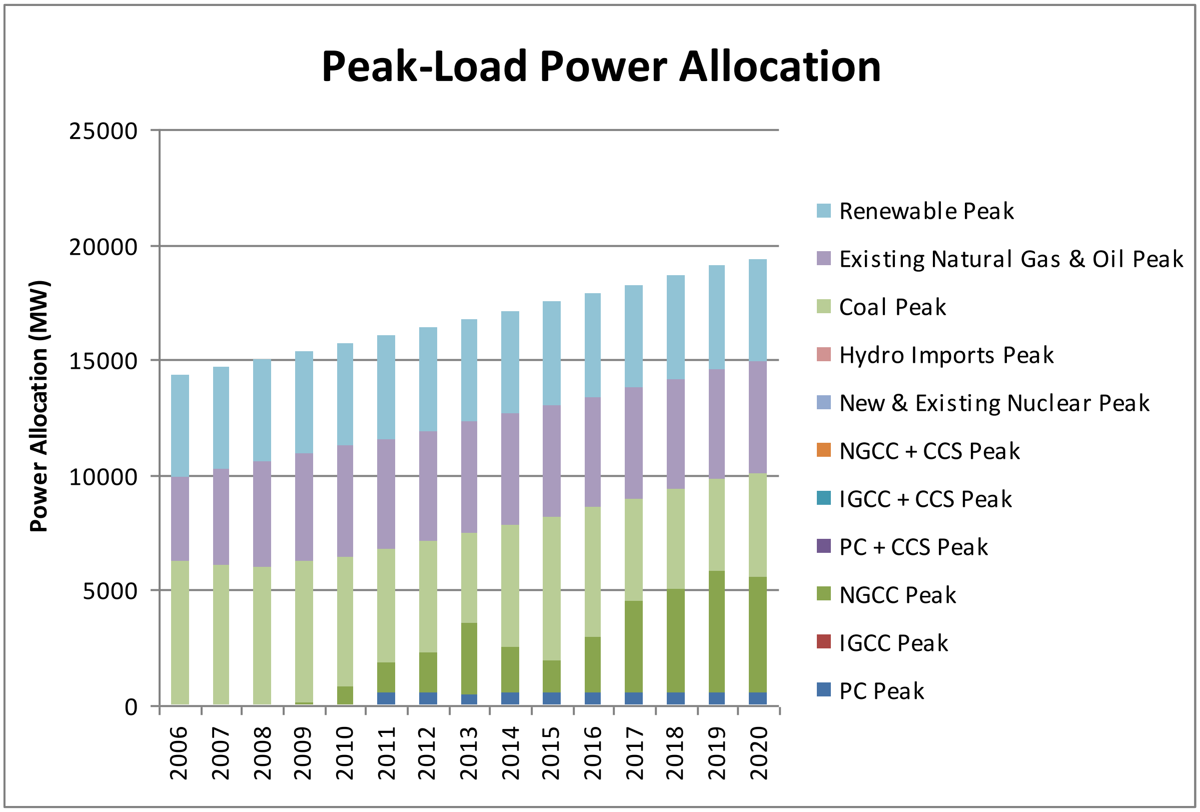



**Figure 24 –** Case Study I: Power allocated to meet peak-load demand (MW).

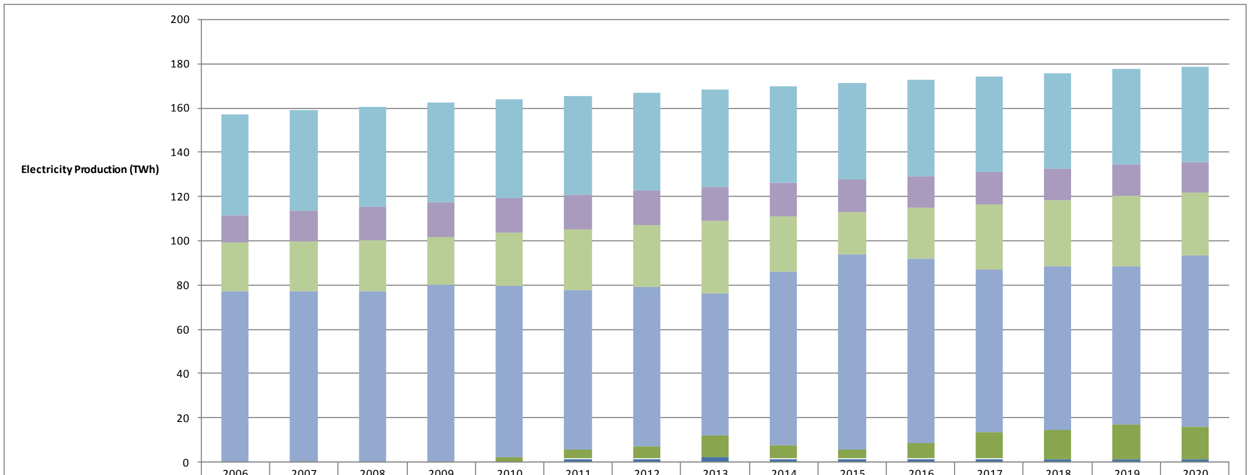
As shown in Figure 23, base-load demand is mostly satisfied by the utilization of renewable, coal, and nuclear power. In 2013, in addition to renewable, coal, and nuclear, 115 MW of power is allocated from the new PC generating unit. The model did not allocate any power from NGCC or existing NG and oil sources to meet base-load demand. This may be because in order to meet base-load demand the unit would have to be operated continuously, and as natural gas is an expensive fuel source it most likely was not cost-effective to use NGCC for base-load.

During the time period between 2006 and 2020, the forecasted base-load demand varies and power allocation is adjusted to meet demand accordingly.

As illustrated in Figure 24, peak-load demand is satisfied by various supply sources, including NGCC, renewable, coal, PC, and existing NG and oil. In this case, NGCC and existing NG and oil are utilized since they are operated only during periods of peak demand and are hence cost-effective. The model did not allocate any power from nuclear sources due to the assumption that nuclear units can only be used to meet base-load demand (see Section 4.3).

During the time period between 2006 and 2020, the forecasted peak-load demand increases steadily and new power plants must be brought online in order to satisfy this demand.

The total electricity production (TWh) from each supply technology for the base case is presented in Figure 25. The percent of electricity production from each supply source for years 2006, 2010, 2015 and 2020 is given in Figure 26.




| | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Renewable | 46 | 45 | 45 | 45 | 45 | 44 | 44 | 44 | 44 | 44 | 44 | 43 | 43 | 43 | 43 |
| Existing NG & Oil | 13 | 14 | 15 | 16 | 16 | 16 | 15 | 15 | 15 | 15 | 15 | 14 | 14 | 14 | 14 |
| Coal | 22 | 22 | 23 | 22 | 24 | 28 | 28 | 33 | 25 | 19 | 23 | 29 | 30 | 32 | 28 |
| Hydro Imports | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Nuclear | 78 | 78 | 78 | 80 | 77 | 72 | 72 | 65 | 78 | 88 | 84 | 74 | 74 | 72 | 78 |
| NGCC + CCS | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| IGCC + CCS | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| PC + CCS | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| NGCC | 0 | 0 | 0 | 0.34 | 3 | 4 | 6 | 10 | 6 | 4 | 7 | 12 | 13 | 15 | 14 |
| IGCC | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| PC | 0 | 0 | 0 | 0 | 0 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 |

**Figure 25 –** Case Study I: Total electricity production (TWh) from all supply sources.

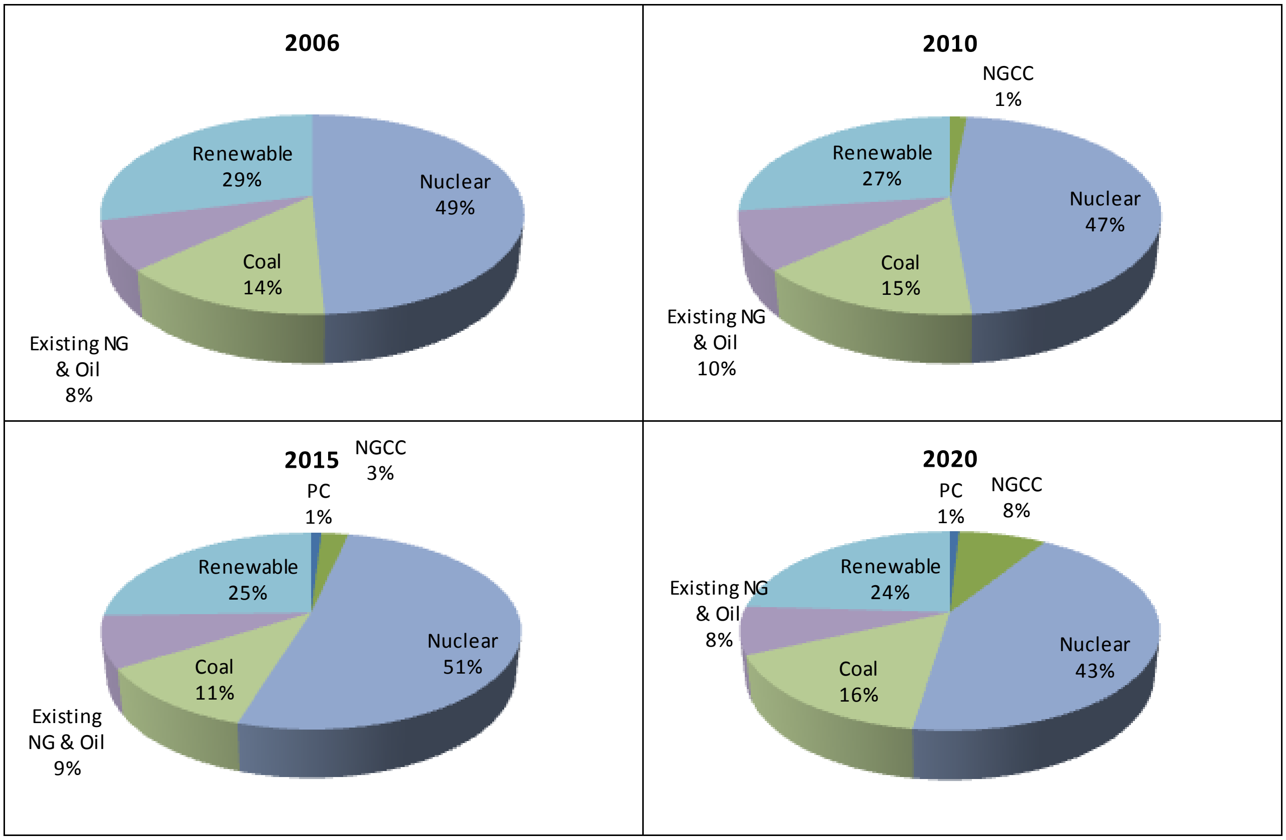



**Figure 26 –** Case Study I: The percent of electricity production from each supply source for years 2006, 2010, 2015 and 2020.

As shown in Figure 25 and Figure 26, a significant amount of electricity production is generated from nuclear power. The electricity produced from nuclear power plants ranges from 65 TWh in 2013 to 88 TWh in 2015. By the year 2015, nuclear power produces about 51% of the electricity needed to meet Ontario's demand.

Electricity production from NGCC becomes part of the energy mix in 2009, once the first NGCC power plant has been constructed. The electricity production from NGCC ranges from 0.34 TWh in 2010 to 15 TWh in the year 2019. Electricity generation from new PC power plants remains constant from 2011 through 2020. Electricity production from existing NG and oil, coal, and renewable sources generally decreases over time, as new, more efficient supply sources are introduced to the energy mix.

Figure 27 and Figure 28 illustrate the electricity production generated to meet base-load and peak-load, respectively.

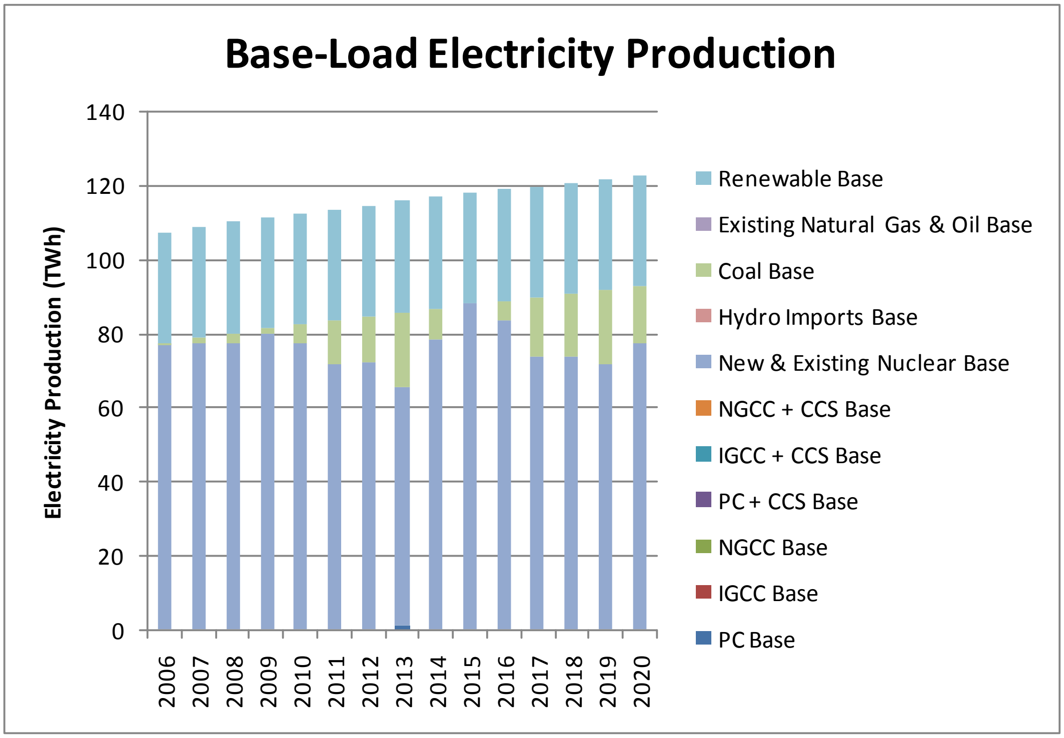



**Figure 27 -** Case Study I: Electricity production generated to meet base-load demand (TWh).

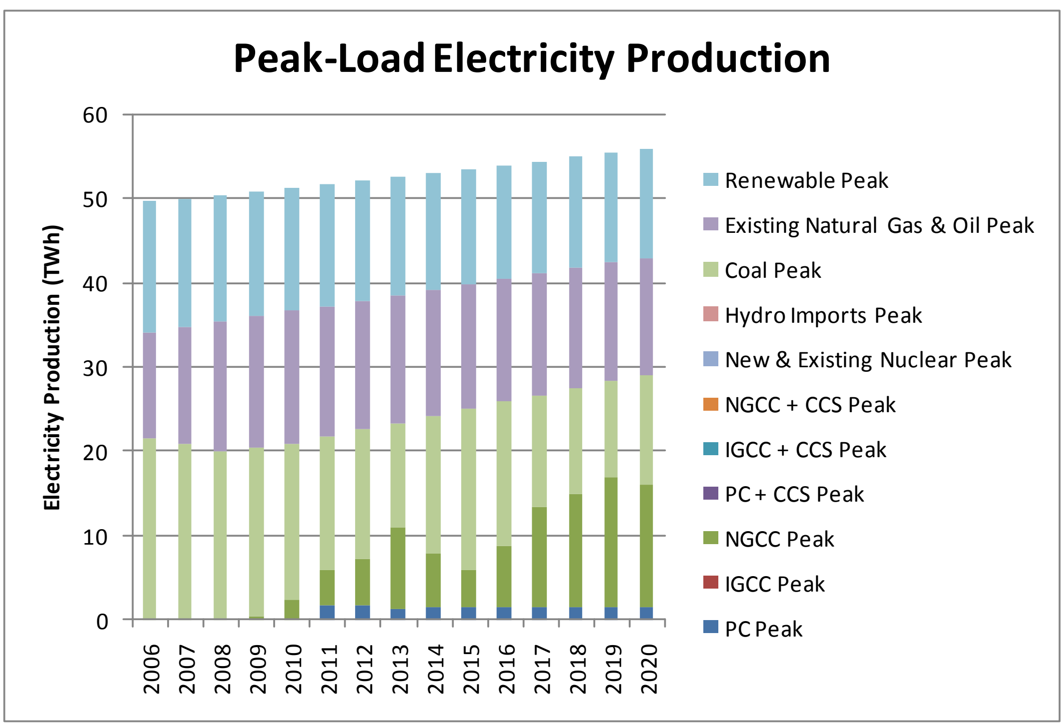



**Figure 28** - Case Study I: Electricity production generated to meet peak-load demand (TWh).

Electricity generated to meet base-load demand comes predominantly from nuclear power plants. As shown in Figure 27, the electricity generated from nuclear plants accounts for more than half of Ontario's base-load electricity demand. The remaining electricity demand is satisfied by renewable, existing coal, and PC energy. The production of electricity from the PC power plant is introduced only in the year 2013, at which time it produces 1 TWh to help meet base-load demand.

Energy production required to meet peak-load electricity demand is generated from various supply sources. Renewable, existing NG and oil, and coal generate most of the electricity to meet peak-load demand from 2006 through 2020. By year 2018-2019, NGCC sources become a large contributor of electricity.

### *4.5.3 Economic Analysis*

The annual expenditure, presented in 2006 Canadian dollars, of the entire electricity sector is shown in Figure 29. The annual expenses consist of: variable O&M for new and existing power station, fixed O&M for new and existing power station, capital cost associated with fuel-switching, cost refurbishment of existing nuclear units, cost of $CO_2$ credits, fuel costs, and capital cost for construction of new power stations.

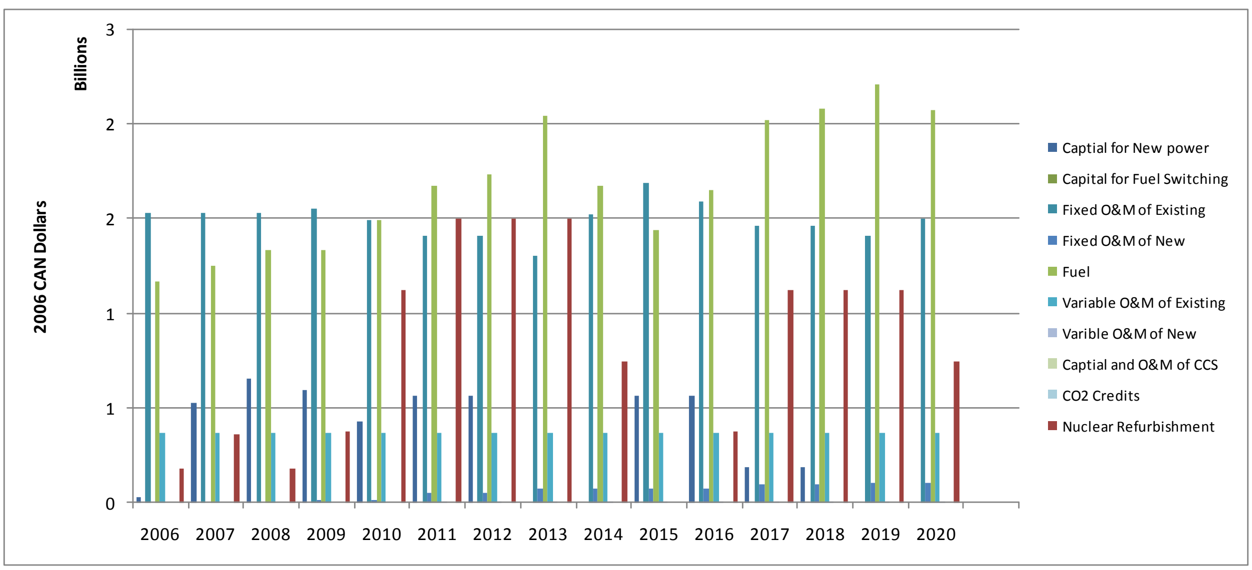



**Figure 29 –** Case Study I: Annual expenditure of entire electricity sector. All costs are expressed in terms of 2006 Canadian dollars.

As shown in Figure 29, the major factors which contribute to the cost of generating electricity are fuel cost, refurbishment cost for existing nuclear units, and fixed O&M cost for existing power stations.

The cost of fuel is the largest contributor to the total annual cost of generating electricity. Fuel cost for the entire fleet rises steadily from 2006 to 2011. The observed increase in fuel prices is mainly due to a rise in electricity demand, variability in natural gas prices and utilization of new power stations. The cost of fuel drops during 2014-2015, but steadily continues to rise after 2015 and reaches a maximum of $2.2 billion in year 2019.

The cost of nuclear refurbishment is particularly large from 2010 to 2014. During this time period, 9 nuclear units are scheduled to be refurbished. The maximum refurbishment cost of existing nuclear units occurs during the years 2011-2013.

The fixed O&M cost for existing power stations remains relatively steady during the entire time horizon studied. The maximum expenditure for fixed O&M costs is incurred during year 2015, at a cost of $1.68 billion.

The lowest contributor to the annual expenditure is the variable O&M costs for new power plants. The variable O&M costs associated with new power stations is not considered until the year 2009, since no new power plants have been built until this time. After 2009, a new NGCC-22 power station is brought online and the fixed O&M cost associated with operating this power plant is accounted for. The variable O&M cost for new power stations increases after 2009 as new power station are built, and reaches a maximum of $100.9 million in year 2020.

The costs association with fuel switching, CCS, and carbon credit purchases are zero since these options were not realized in this case study.

The breakdown of the total expenditure by sector for the entire study period (2006-2020) is presented in Figure 30.

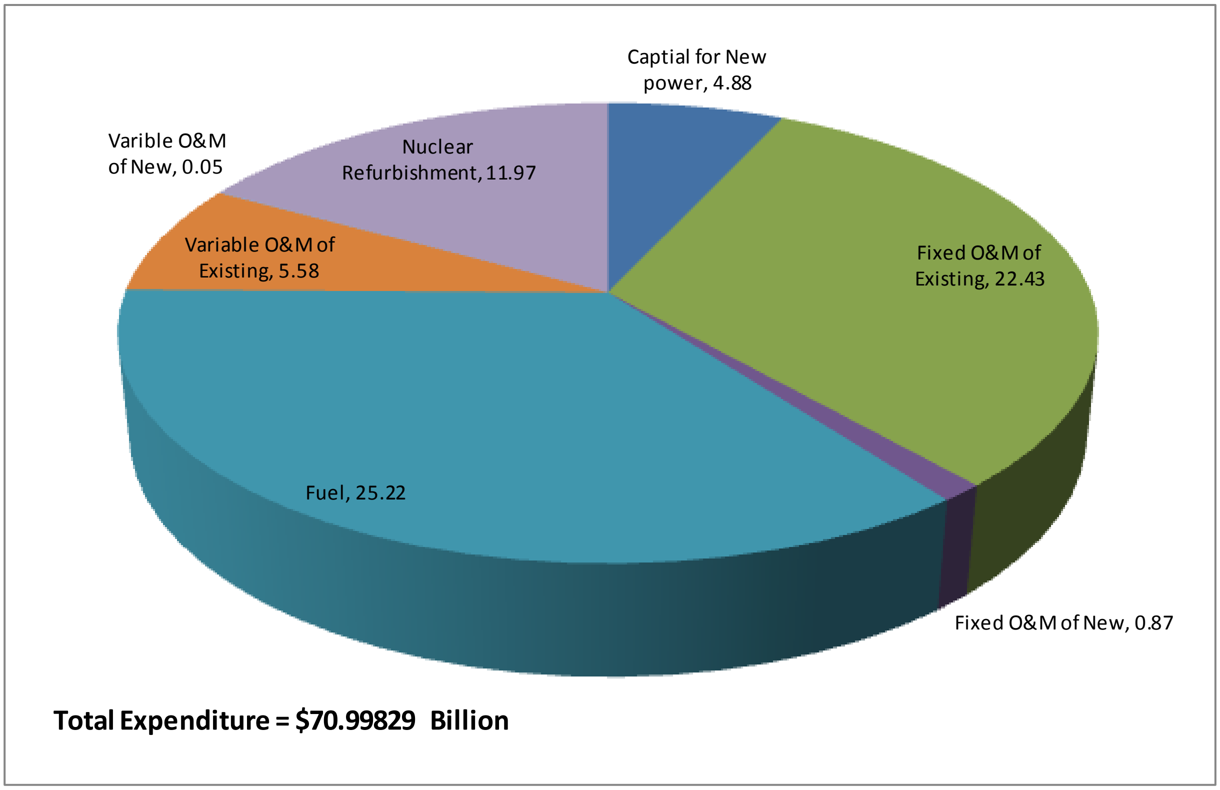



**Figure 30** - Case Study I: Total expenditure for entire study period (2006-2020). All costs are expressed in terms of 2006 Canadian dollars ($billion).

As shown in Figure 30, the highest contributors to the total expenditure are cost of fuel, fixed O&M costs for existing generating stations, and nuclear refurbishment cost, with a total cost of $25.22, $22.43 and $11.97 billion, respectively. This is in-line with the year-to-year results shown in Figure 29. Variable cost associated with new power plants accounts for the lowest part of the total expenditure, with a total cost of $50 million. The total expenditure for the entire study period is $70.10 billion.

The cost of electricity (COE) during the period under study is presented in Figure 31. The COE values were obtained by dividing total annual expenditure with the annual electricity production. The average COE for the study period is 2.804 cents/kWh.

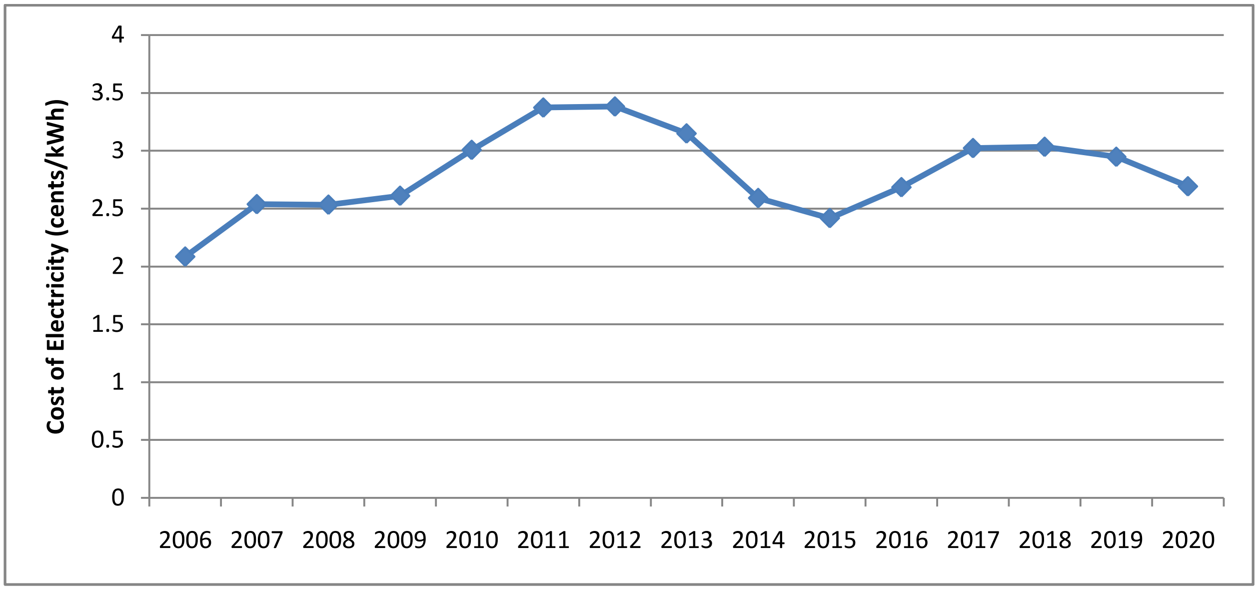



**Figure 31 -** Case Study I: Annual cost of electricity (COE) for the entire study period (2006-2020). All costs are expressed in terms of 2006 Canadian dollars.

As shown in Figure 31, the COE varies significantly throughout the span of the study period. The COE ranges from a minimum of 2.09 cents/kWh in 2006, to a maximum of 3.38 cents/kWh in 2012. The variability associated with the COE in any particular year is dependent on all the factors that are considered in the total expenditure for that year. For instance, the high COE observed in year 2012 is due to a large amount of capital spent on fuel, construction of new power plants, and refurbishment of nuclear units, relative to how much electricity is generated. Similarly, the low COE experienced in 2006 is due to the low capital expenditure spent relative to the electricity generated.

### *4.5.4 Carbon Dioxide Emissions*

Annual $CO_2$ emissions from the entire fleet are presented in Figure 32. The total $CO_2$ emission over the study period amount to 525 Mt. Note that no $CO_2$ emissions limits are imposed on the base case, and hence it is expected that the base case will have the highest $CO_2$ emissions from the two case studies examined in this thesis.

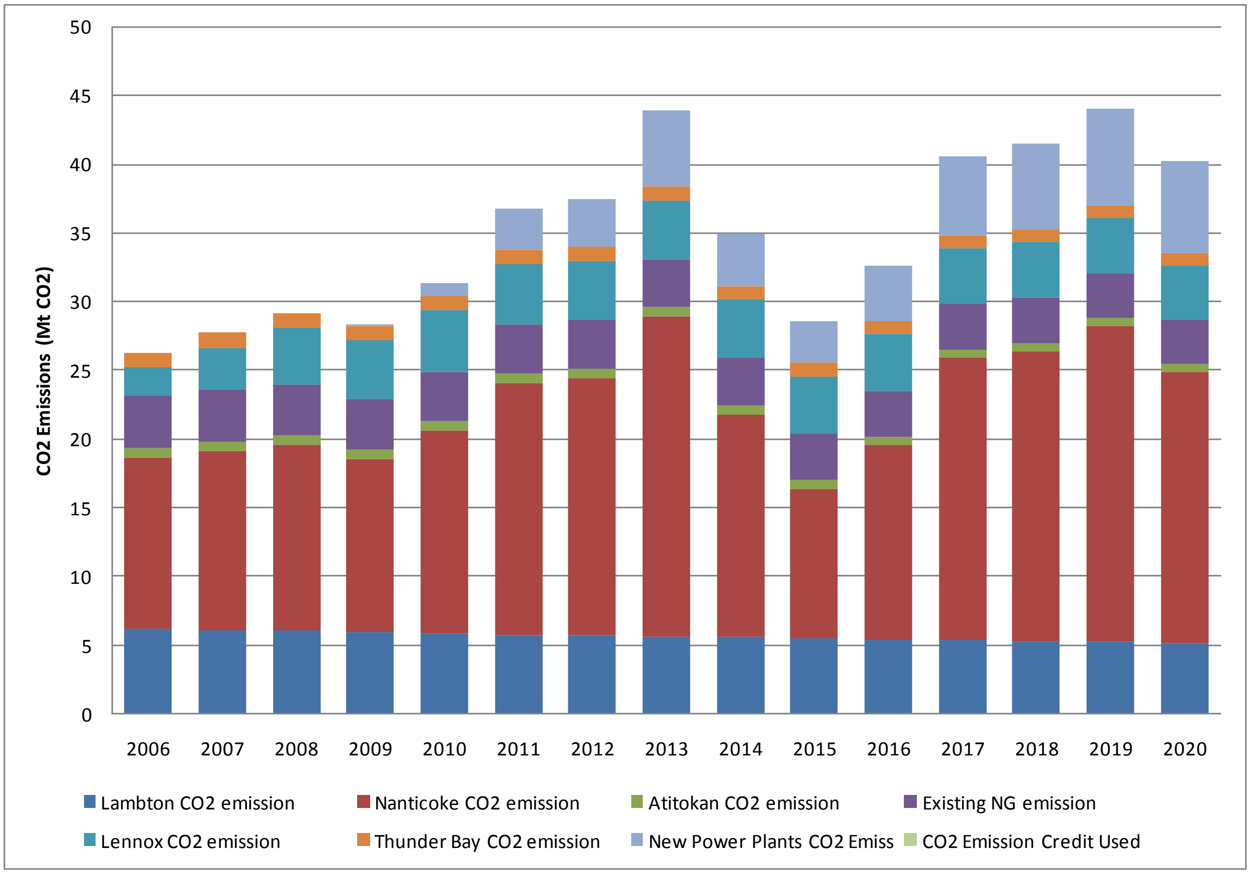



**Figure 32 -** Case Study I: Annual carbon dioxide emissions (Mt $CO_2$) from entire fleet.

As can be seen in Figure 32, the annual $CO_2$ emissions from the entire fleet vary significantly from year-to-year.

The $CO_2$ emissions increase steadily from year 2006 through 2013, reaching a maximum peak of 44.052 Mt. After the year 2013, $CO_2$ emissions briefly decrease but go back up and continue rising after 2015. The maximum $CO_2$ generated occurs in 2019, with a total of 44.058 Mt of $CO_2$ released to the atmosphere.

As shown in Figure 32, the Nanticoke coal-fired generating station is the single largest source of $CO_2$ emissions. In 2013, Nanticoke alone was responsible for 52.98% of the $CO_2$ emissions generated from the entire fleet.

Since $CO_2$ emissions from other locations remain relatively constant throughout the study period, it seems that Nanticoke is mainly responsible for the observed variability in $CO_2$ emissions over the time period studied.

## *4.6 Case Study II: $CO_2$ emissions 6% below 1990 levels*

Case Study II presents a scenario in which Ontario's electricity sector must comply with annual $CO_2$ emissions 6% below 1990 levels. This regulation comes into effect after year 2011. There are no $CO_2$ emission limits enforced between 2006 and 2011. After the year 2011, Ontario's fleet must comply with an annual $CO_2$ emission limit of 20 Mt (6% below 1990 level). Moreover, this case study assumes that a carbon credit system or market is established in which individual power stations may purchase carbon credits at a cost. It is assumed that the technology for CCS in Ontario is available and can be implemented if needed.

This case study also assumes that the phase-out of the coal power plants is not enforced by the policy makers. The existing nuclear power units will be refurbished based upon their estimated end-of-service dates. Furthermore, the assumption is made that all new or existing nuclear power plants are only used to meet base-load demand and are not utilized to satisfy peak-demand. Wind power will be used for the purpose of meeting peak demand and not base load demand.

Results for Case Study II are presented in the following sub-sections.

## *4.6.1 Fleet Structure: New construction, fuel-switching, and CCS retrofit*

Table 20 illustrates the construction of new power stations for Case Study II. It includes the year in which the construction of new power plants started (represented by an “X”), as well as the years during which the unit is under construction (represented by the shaded area).

**Table 20–** Case Study II: Construction of new power stations. The “X” represents the year in which construction of the new generating unit started and the shaded are represents the years during which the unit is under construction. The years after the shaded areas assume the unit to be fully operational.

| | Net Capacity (MW) | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **New Power Plant Without CCS** | | | | | | | | | | | | | | | | |
| **NGCC21** | 506.5 | X | | | | | | | | | | | | | | |
| **NGCC32** | 1519.6 | | X | | | | | | | | | | | | | |
| **NGCC33** | 2279.4 | | | | X | | | | | | | | | | | |
| **New Power Plant With CCS** | | | | | | | | | | | | | | | | |
| **NGCC21** | 432.3 | | | | X | | | | | | | | | | | |
| **NGCC31** | 648.4 | | | | X | | | | | | | | | | | |
| **Nuclear Power Plants** | | | | | | | | | | | | | | | | |
| **ACR-700** | 1406 | X | | | | | | | | | | | | | | |

From Figure 26, it can be seen that for Case Study II, three new NGCC power plants without CCS and two NGCC power plants with CCS system need to be built between 2006 and 2020. The net capacity of all new NGCC units without CCS and NGCC with CCS totals 4,305.5 MW and 1,080.7 MW respectively.

In addition to the three new NGCC power plants, one ACR-700 nuclear power plant is built in 2006. The net capacity of this nuclear power plant is 1,406 MW. The ACR-700 power plant will be under construction for 7 years and will be available for service after 2012.

For this case study, the model selected to keep all existing coal, natural gas, wind, and hydroelectric power stations operational throughout the study period (2006-2020).

Fuel-switching was implemented at Nanticoke, Atikokan, and Thunder Bay during the years 2012, 2017, and 2017 respectively. Table 21, illustrates the coal power plants that have been fuel-switched to NG. The "X" in Table 21 represents the year in which fuel-switching should be implemented and the shaded area represents the years in which that particular power plant is operated using NG as its fuel.

**Table 21** - Case Study II: Existing coal power plants that have been fuel-switched to natural gas. The "X" represents the year in which fuel-switching was implemented and the shaded area represents the years in which that specific coal power plant is using natural gas as its fuel source.

| | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Lambton** | | | | | | | | | | | | | | | |
| **Nanticoke** | | | | | | | X | | | | | | | | |
| **Atikokan** | | | | | | | | | | | | X | | | |
| **Lennox** | | | | | | | | | | | | | | | |
| **Thunder Bay** | | | | | | | | | | | | X | | | |

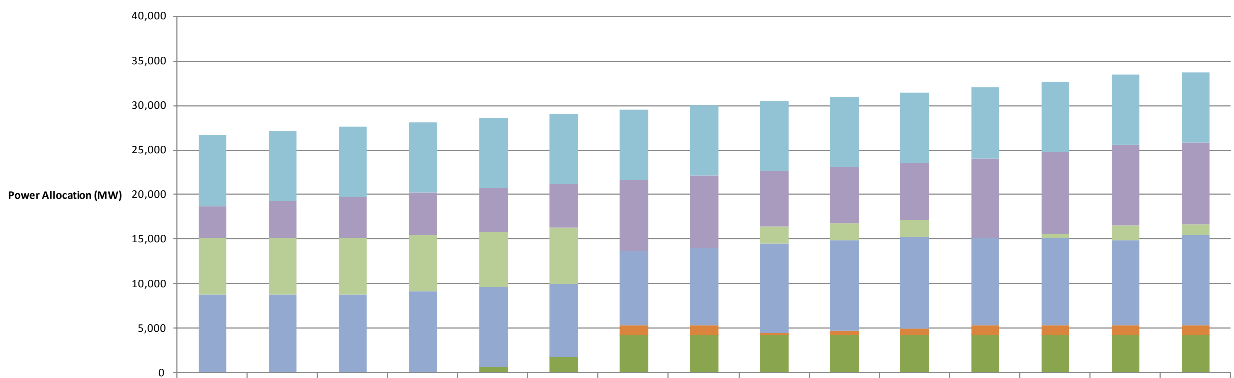
As shown in Table 22, a CCS system is to be retrofitted onto Lambton coal power plant in 2018. The "X" in Table 22 represents the year in which CCS retrofit should be implemented and the shaded area represents the years in which that particular power plant is operating with CCS system in place.

**Table 22 -** Case Study II: Existing coal power plants that have been retrofitted with a CCS system. The "X" represents the year in which the coal power plant was retrofitted with a CCS system and the shaded area represents the years in which the plant is operating with a CCS system in place.

| | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Lambton** | | | | | | | | | | | | | X | | |
| **Nanticoke** | | | | | | | | | | | | | | | |
| **Atikokan** | | | | | | | | | | | | | | | |
| **Lennox** | | | | | | | | | | | | | | | |
| **Thunder Bay** | | | | | | | | | | | | | | | |

## 4.6.2 Power Allocation and Electricity Production

Total power (MW) allocated from each supply technology for the base case is presented in Figure 33. The percent of power allocation based on generating technology for years 2006, 2010, 2015 and 2020 is given in Figure 34.




| | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Renewable | 7902 | 7902 | 7902 | 7902 | 7902 | 7902 | 7902 | 7902 | 7902 | 7902 | 7902 | 7902 | 7902 | 7902 | 7902 |
| Existing NG & Oil | 3615 | 4098 | 4598 | 4770 | 4814 | 4814 | 7975 | 8081 | 6164 | 6289 | 6416 | 8983 | 9151 | 8985 | 9151 |
| Coal | 6285 | 6285 | 6285 | 6285 | 6285 | 6285 | 0 | 0 | 1948 | 1948 | 1948 | 0 | 477 | 1769 | 1140 |
| Hydro Imports | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Nuclear | 8849 | 8849 | 8849 | 9144 | 8820 | 8227 | 8253 | 8630 | 9941 | 10057 | 10172 | 9695 | 9695 | 9446 | 10122 |
| NGCC + CCS | 0 | 0 | 0 | 0 | 0 | 0 | 1081 | 1081 | 236 | 471 | 719 | 1081 | 1081 | 1081 | 1081 |
| IGCC + CCS | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| PC + CCS | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| NGCC | 0 | 0 | 0 | 51 | 772 | 1820 | 4306 | 4306 | 4306 | 4306 | 4306 | 4306 | 4306 | 4306 | 4306 |
| IGCC | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| PC | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |

**Figure 33 -** Case Study II: Total power allocated (MW) from each supply technology.

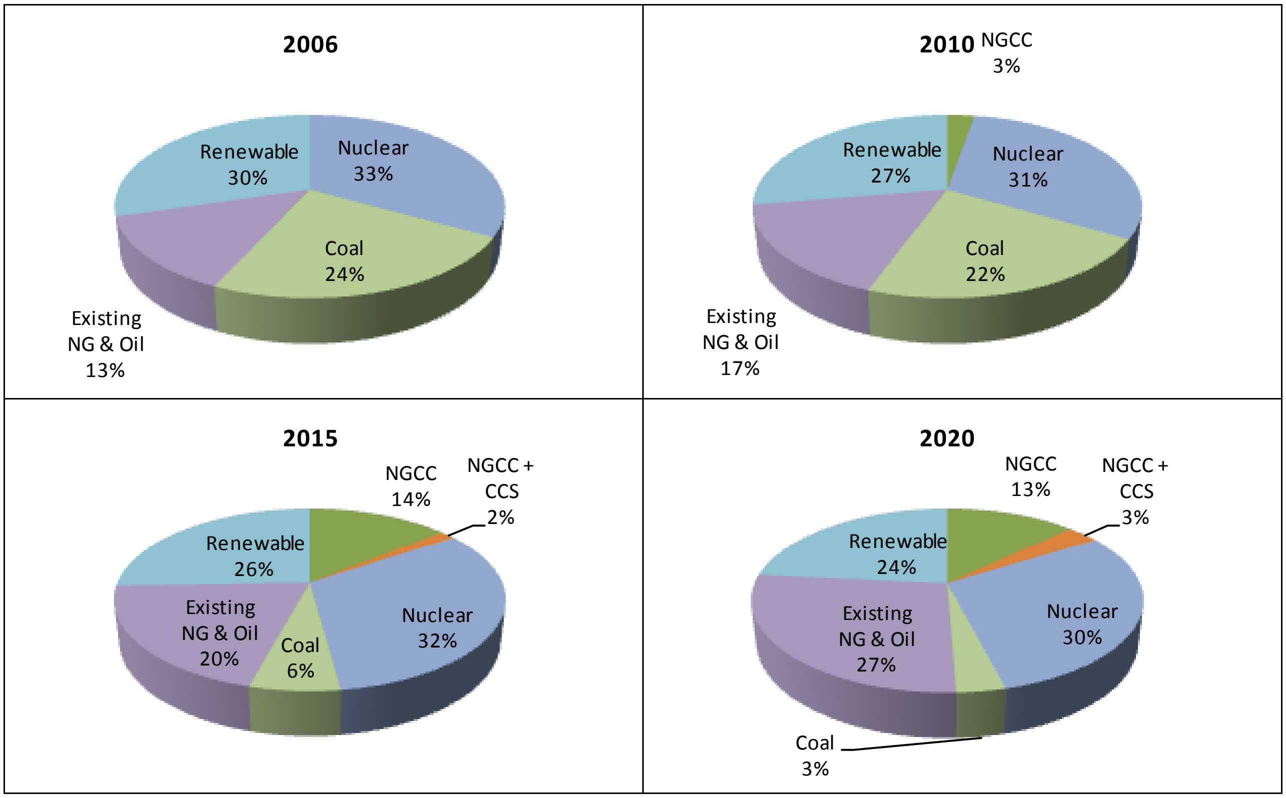



**Figure 34 -** Case Study II: Total power allocation in terms of percentage for the years 2006, 2010, 2015 and 2020.

From Figure 33, it can be seen that the power allocated from renewable sources stays constant at a maximum level of 7,902 MW. As discussed in Section 4.3, the maximum capacity is reached because no new renewable supply sources are considered in the two case studies.

Existing NG and oil allocation reaches a maximum of 9,151 MW in 2018. The increase in the maximum capacity of existing NG and oil plants is due to the fact that Nanticoke, Atikokan, and Thunder Bay coal power stations undergo fuel-switching during years 2012, 2017, and 2017 respectively.

Power allocated from coal power plants ranges from 0 MW to 6,269 MW, as shown in Figure 33**.** Coal power is highly utilized throughout the time frame in which no $CO_2$ limits are imposed on Ontario's electricity sector (2006-2011).

In years 2012, 2013, and 2017 there is no power production from any of the Coal power plants. During these years other electricity-generating technologies must be utilized in order to fill the energy gap created. Electricity-generating technologies used during these years include NGCC+CCS and existing NG and oil.

As shown in Figure 33, no long term hydroelectric imports are realized. Furthermore, power allocated from nuclear plants ranges from 8,820 MW in year 2010 to 10,172 MW in 2016. The construction of the new ACR-700 nuclear power plant is completed at the end of 2012. After 2012, the newly constructed nuclear units are available for power supply to the grid.

No IGCC+CCS, PC+CCS, IGCC, and PC were constructed during the time horizon considered, and hence no power was allocated from these supply sources. From Figure 33, power allocated from NGCC ranges from 51 MW in 2014 to 4,306 MW in 2012. The power allocated by NGCC+CCS ranges from a minimum of 236 MW to maximum of 1,081 MW.

From Figure 34, it can be seen that in year 2006, 13% of power is allocated from existing NG and oil, 24% from coal, 30% from renewable sources and 33% from nuclear plants**.**

As energy demand rises over the years, the percent of power allocated from nuclear sources remains relatively constant. This constant percentage from the total supply mix is maintained due to the construction of the new ACR-700 nuclear power plant which is scheduled to start producing electricity by 2013.

While the percent power allocation from nuclear power plants remains constant, the percent power allocated by coal power plants decreases over time. In 2006, the percent of power allocation from coal power plants is 24%. By 2020, the percent of power allocated from coal power plants amounts to only 3% of the total mix.

Figure 35 and Figure 36 show the power (MW) allocated from each supply source to meet base-load and peak-load demands respectively.

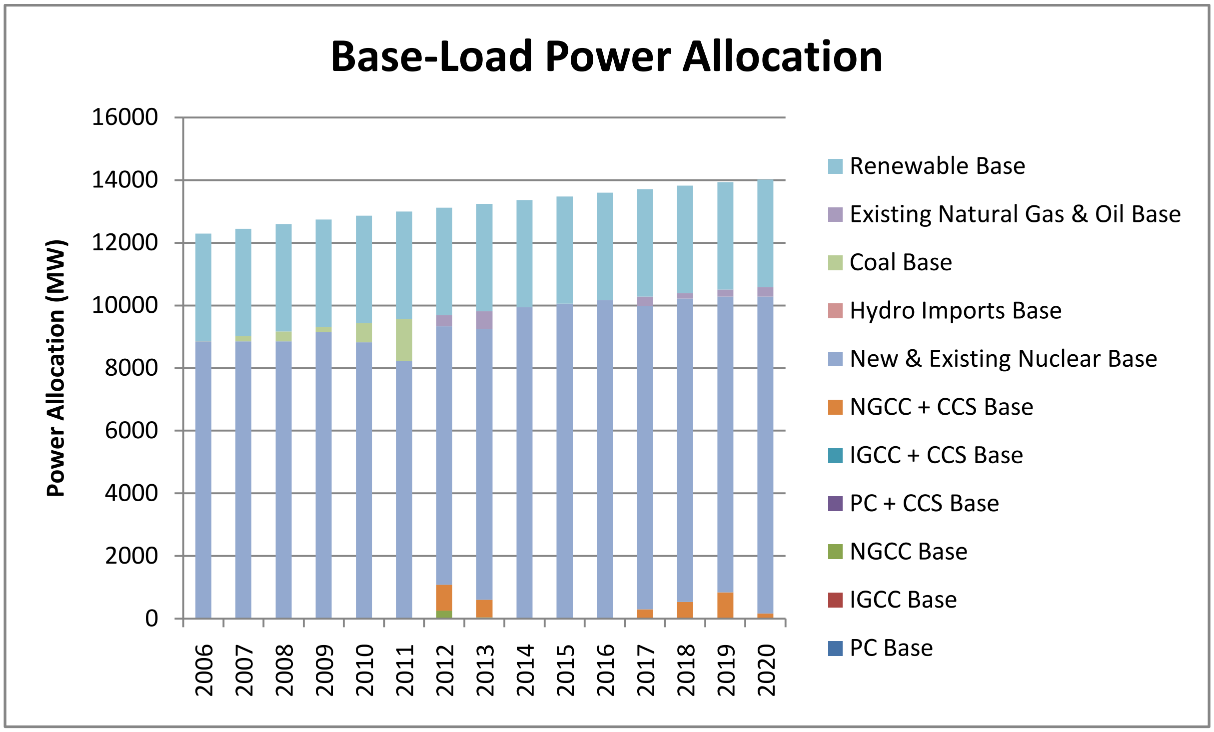



**Figure 35 -** Case Study II: Power allocated to meet base-load demand (MW).

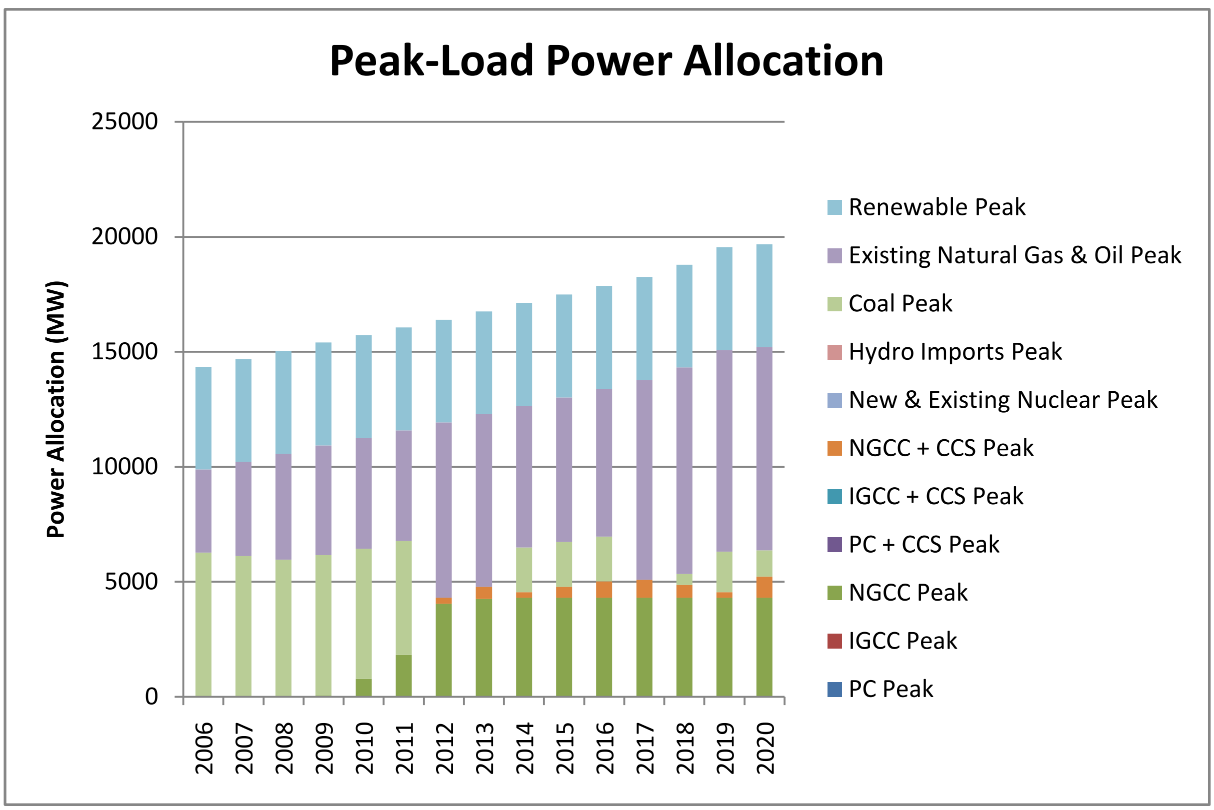



**Figure 36 -** Case Study II: Power allocated to meet peak-load demand (MW).

As shown in Figure 35, base-load demand is predominantly satisfied with use of renewable and nuclear power. The reason these two technologies are primarily used to meet base-load demand is because they are cheap and clean technologies that may be used to generate electricity on a continuous basis.

Coal power plants are utilized in order to help meet base-load demand during the time period in which no $CO_2$ emission constraints are imposed on the electricity sector (2006-2011). After 2011, the year after which $CO_2$ emissions are imposed, the use of coal technology is no longer utilized to meet base-load demand. The use of coal technology to meet base-load demand is no longer chosen after year 2011 because of the high $CO_2$ emissions that coal power plants generate.

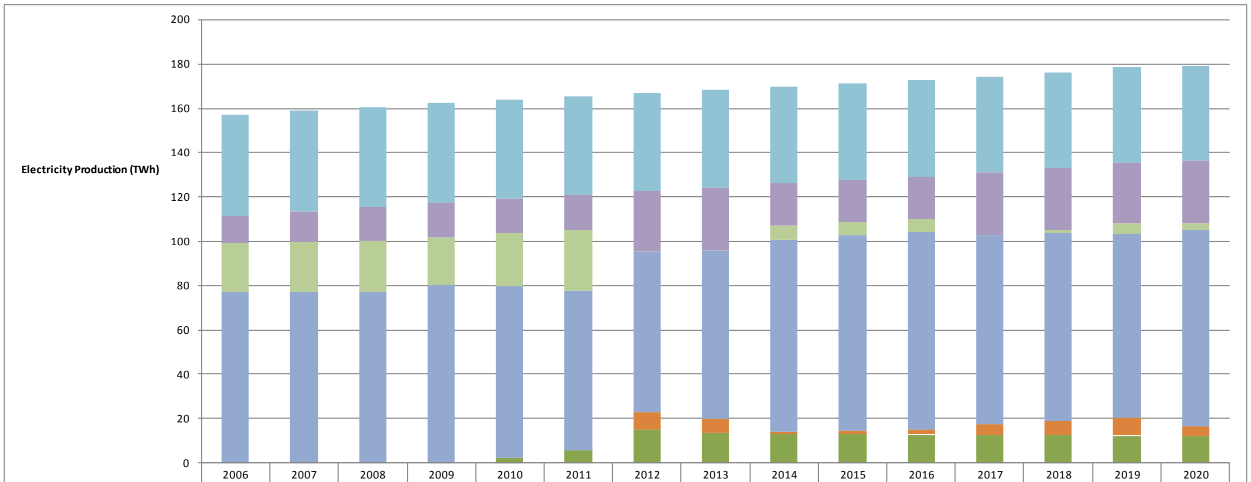
NGCC, NGCC+CCS, and existing NG and oil power plants are used to meet base-load demand after the year 2011. The utilization of these generating technologies in order to meet base-load demand is minimal due to the high fuel-cost associated with the continuous operation of these plants.

As illustrated in Figure 36, peak-load demand is satisfied by various supply sources, including NGCC, NGCC+CCS, renewable, coal, and existing NG and oil. Conversely to base-load demand, NGCC is highly utilized since it is operated only during periods of peak demand and is hence cost-effective. The model did not allocate any power from nuclear sources due to the assumption that nuclear units can only be used to meet base-load demand (see Section 4.3).

The utilization of coal power in order to meet peak-load demand decreases significantly after the year 2011. The decrease in power allocation from coal power plants is due to the $CO_2$ emission restrictions imposed on the electricity sector after this year. In order to reduce $CO_2$ emissions to target levels, the model chose to reduce the use of coal power plants, and instead utilize less carbon-intensive fueled plants such as NGCC.

During the time period between 2006 and 2020, the forecasted peak-load demand increases steadily and new power plants must be brought online in order to satisfy this demand.

The total electricity production (TWh) from each supply technology for Case Study II is presented in Figure 37. The percent of electricity production from each supply source for years 2006, 2010, 2015 and 2020 is given in Figure 38.




| | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Renewable | 46 | 45 | 45 | 45 | 45 | 44 | 44 | 44 | 44 | 44 | 44 | 43 | 43 | 43 | 43 |
| Existing NG & Oil | 13 | 14 | 15 | 16 | 16 | 16 | 27 | 29 | 19 | 19 | 19 | 29 | 28 | 27 | 28 |
| Coal | 22 | 22 | 23 | 22 | 24 | 28 | 0 | 0 | 6 | 6 | 6 | 0 | 1 | 5 | 3 |
| Hydro Imports | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Nuclear | 78 | 78 | 78 | 80 | 77 | 72 | 72 | 76 | 87 | 88 | 89 | 85 | 85 | 83 | 89 |
| NGCC + CCS | 0 | 0 | 0 | 0 | 0 | 0 | 8 | 7 | 1 | 1 | 2 | 5 | 6 | 8 | 4 |
| IGCC + CCS | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| PC + CCS | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| NGCC | 0 | 0 | 0 | 0.2 | 3 | 6 | 15 | 14 | 13 | 13 | 13 | 13 | 13 | 13 | 12 |
| IGCC | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| PC | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |

**Figure 37 -** Case Study II: Total electricity production (TWh) from all supply sources.

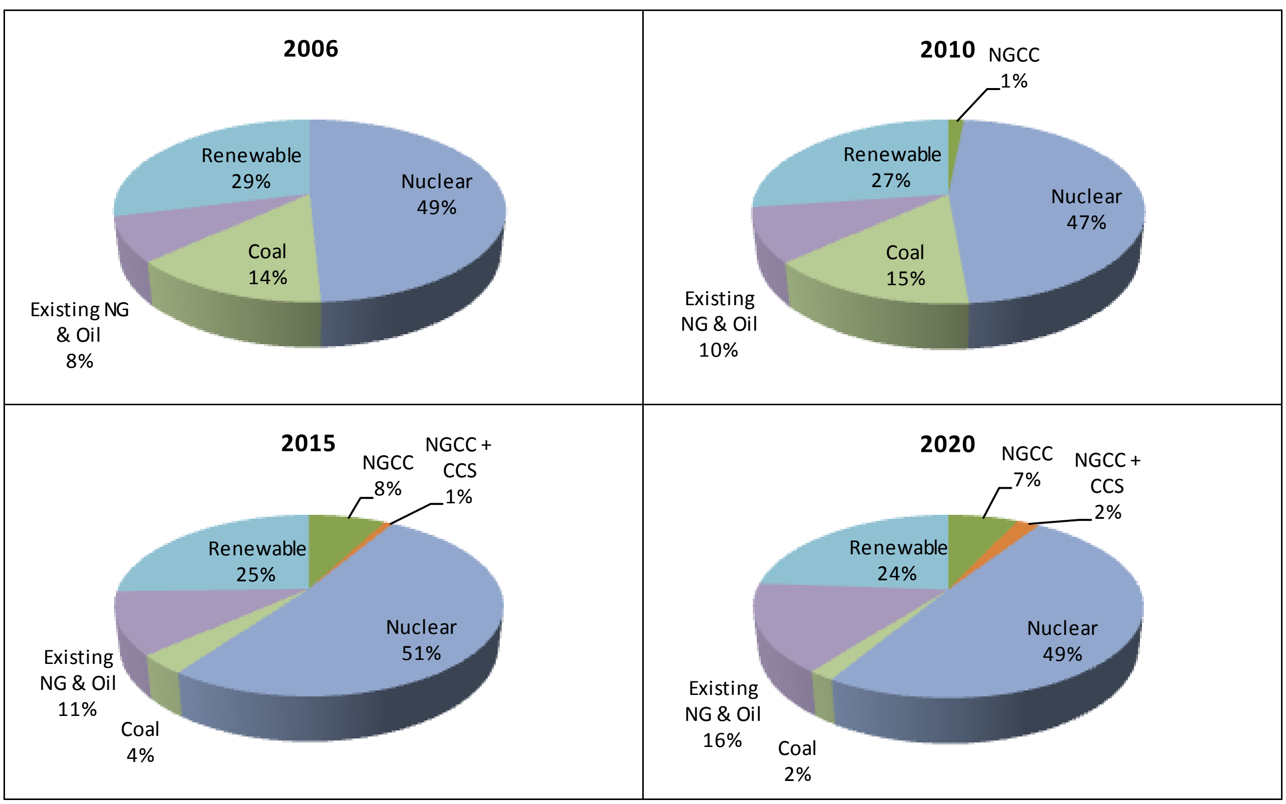



**Figure 38** – Case Study II: The percent of electricity production from each supply source for years 2006, 2010, 2015 and 2020.

As shown in Figure 37 and Figure 38, a significant amount of electricity production is generated from nuclear power. The electricity produced from nuclear power plants ranges from 72 TWh to 89 TWh. By year 2015, nuclear power produces about 51% of the electricity needed to meet Ontario's demand.

Electricity production from NGCC commences in 2009, after the first NGCC power plant has been constructed. The electricity production from NGCC rages from 0.2 TWh in 2009 to 13 TWh in the year 2014. Electricity produced from the two NGCC+CSS is connected to the grid in 2012 and rages from 1 TWh to 8 TWh.

The electricity production from coal power plants decreases significantly after the year 2011. This decrease in electricity production from coal power plants is compensated by increasing the electricity production output of other supply technologies. The underlining reason why the model decided to decrease electricity production from coal power plants is due to the $CO_2$ emission targets set after the year 2011.

Electricity production from existing NG and oil, nuclear, NGCC, and NGCC+CSS generally increase over time. The increase in electricity production from these supply technologies is due to a decline in electricity generation from coal power plants and an increase in electricity demand.

Figure 39 and Figure 40 illustrate the electricity production generated to meet base-load and peak-load respectively.

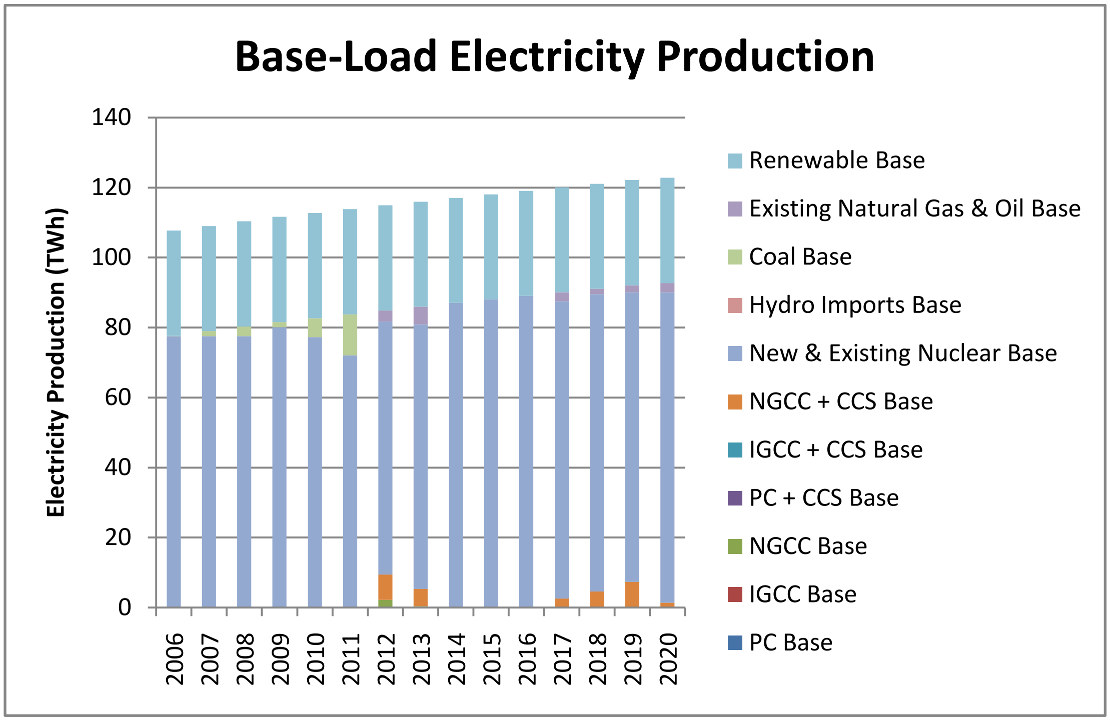



**Figure 39** - Case Study II: Electricity production generated to meet base-load demand (TWh).

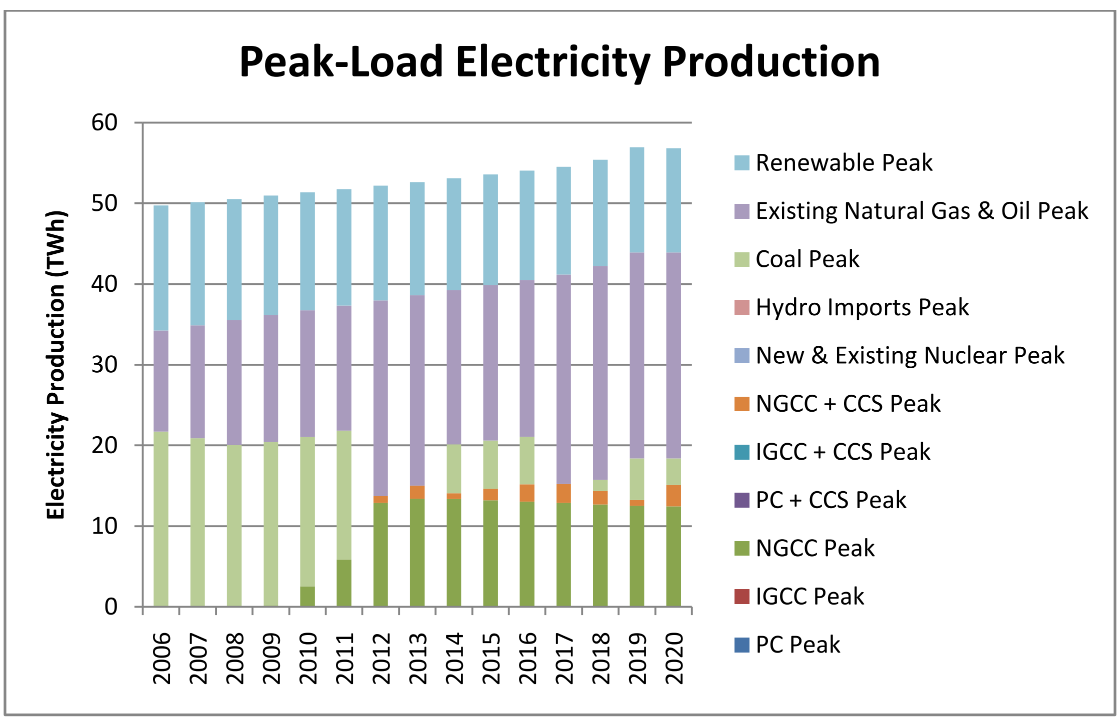



**Figure 40** - Case Study II: Electricity production generated to meet peak-load demand (TWh).

Electricity generated to meet base-load demand is predominantly produced from nuclear power plants. As shown in Figure 39, the electricity generated from nuclear plants accounts for more than half of Ontario's base-load electricity demand. The remaining electricity demand is satisfied by renewable, coal, NGCC, NGCC+CCS, and existing NG and oil supply technologies. After 2011, coal power plants are no longer used in order to meet Ontario's base-load electricity production demand.

Energy production for peak-load electricity demand is generated from various supply sources. Renewable, existing NG and oil, and coal generate most of the electricity to meet peak-load demand from 2006 through 2011. After 2011, coal power plants play a less significant role in energy production for peak-load demand and other supply technologies, such as NGCC, become large contributors to electricity generation.

### *4.6.3 Economic Analysis*

The annual expenditure, presented in 2006 Canadian dollars, of the entire electricity sector is shown in Figure 41. The annual expenses consist of: variable O&M for new and existing power station, fixed O&M for new and existing power station, capital cost associated with fuel-switching, cost refurbishment of existing nuclear units, cost of $CO_2$ credits, fuel costs, and capital cost for construction of new power stations.

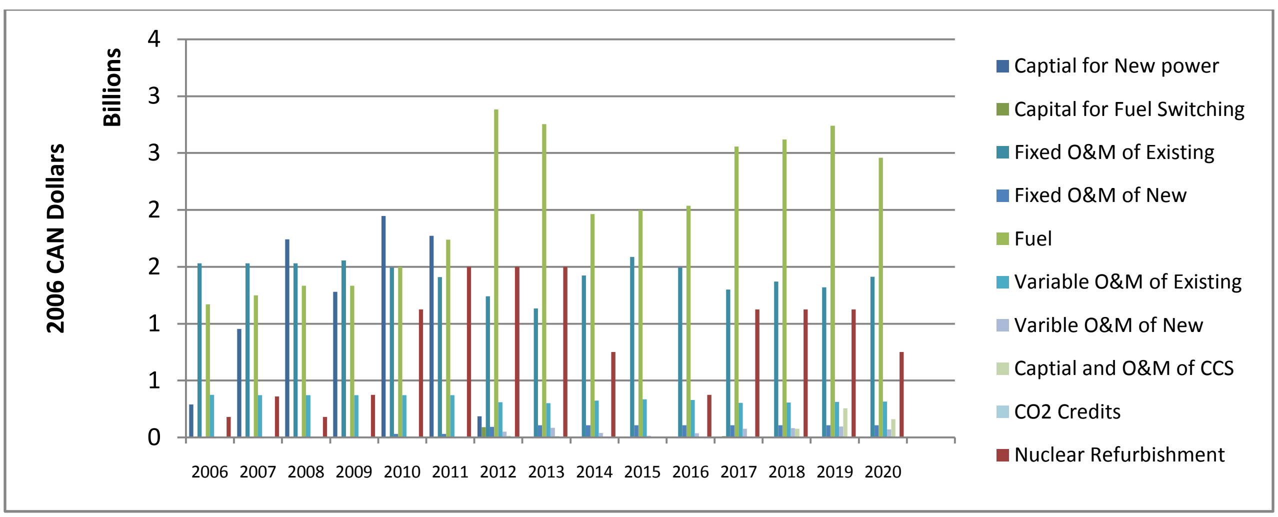



**Figure 41 -** Case Study II: Annual expenditure of entire electricity sector. All costs are expressed in terms of 2006 Canadian dollars.

As shown in Figure 41, the major factors that contribute to the cost of generating electricity are fuel costs, refurbishment costs for existing nuclear units, and fixed O&M costs for existing power stations.

Similar to Case Study I, the cost of fuel is the biggest contributor to the total annual cost of generating electricity. Fuel cost for the entire fleet rises steadily from 2006 to 2012. The increase in fuel prices is mainly due to a rise in electricity demand, variability in natural gas prices, and the utilization of new supply technologies which use natural gas as fuel. The cost of fuel drops during years 2013-2015, but continues to rise steadily after 2015. The highest expenditure occurs in 2012, when $2.8 billion dollars are spent on fuel costs.

The cost of nuclear refurbishment is particularly high from 2010 to 2014. During this time period, 9 nuclear units are scheduled to be refurbished. The maximum expenditure for refurbishment of existing nuclear units occurs during the years 2011-2013.

The fixed O&M cost for existing power stations remains relatively steady during the entire time horizon studied. The maximum expenditure for fixed O&M costs occurs during year 2015, at a cost of $1.59 billion.

The capital expenditure for building new power plants is significantly high from year 2006 through 2012. The high capital expenditure experienced during this time period is due to the construction of 6 new power plants (3 NGCC, 2 NGCC+CCS, and 1 nuclear). The construction of these new units requires a considerable amount of cash-flow during 2006-2012.

The lowest contributor to the annual expenditure is the variable O&M cost for new power plants and the cost associated with CCS. The variable O&M cost associated with new power stations is not considered until the year 2009, since no new power plants have been built until this time. After 2009, a new NGCC-21 power station is brought online and the fixed O&M cost associated with operating this power plant is accounted for. The variable O&M cost for new power stations increases after 2009 as new power station are built, and reaches a maximum of $108.1 million in year 2020.

The cost associated with CCS is considered in the year 2012, when the two new NGCC+CCS power plants are scheduled to start operation. The expenditure for CCS is not significantly high during 2011 through 2017, due to the low amount of $CO_2$ captured and sequestered from the new NGCC power plants. The cost of CCS increases considerably in 2018, when the Lambton coal power plant is retrofitted with a CCS system. The CCS annual expenditure reaches a maximum of 161.7 million in the year 2020.

The cost associated with carbon credits is zero since no carbon credits were purchased in any year.

The breakdown of the total expenditure by sector for the entire study period (2006-2020) is presented in Figure 42.

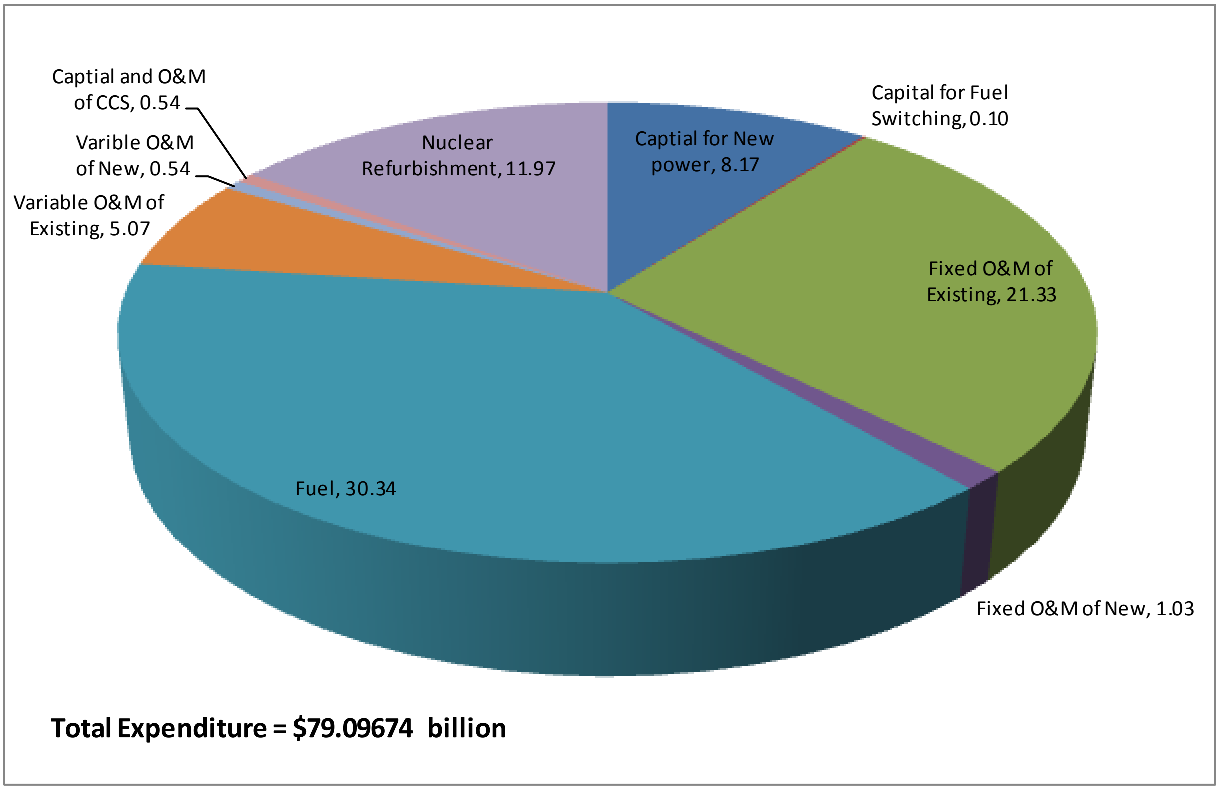



**Figure 42** - Case Study II: Total expenditure for entire study period (2006-2020). All costs are expressed in terms of 2006 Canadian dollars ($billion).

As shown in Figure 42, the highest contributors to total expenditure are cost of fuel, fixed O&M costs for existing generating stations, and nuclear refurbishment costs with a total price of $30.34, $21.33 and $11.97 billion respectively. This is in-line with the year-to-year results shown in Figure 41. The costs associated with fuel-switching, capital and O&M costs of CCS retrofit, and variable cost associated with new power plants accounts for the lowest parts of the total expenditure, with a total cost of $10, $54 and $54 million respectively. The total expenditure for the entire study period is $79.10 billion.

Figure 43 illustrates the annual COE for Case Study II. The COE values were obtained by dividing total annual expenditure with the annual electricity production. The average COE for the study period is 3.129 cents/kWh.

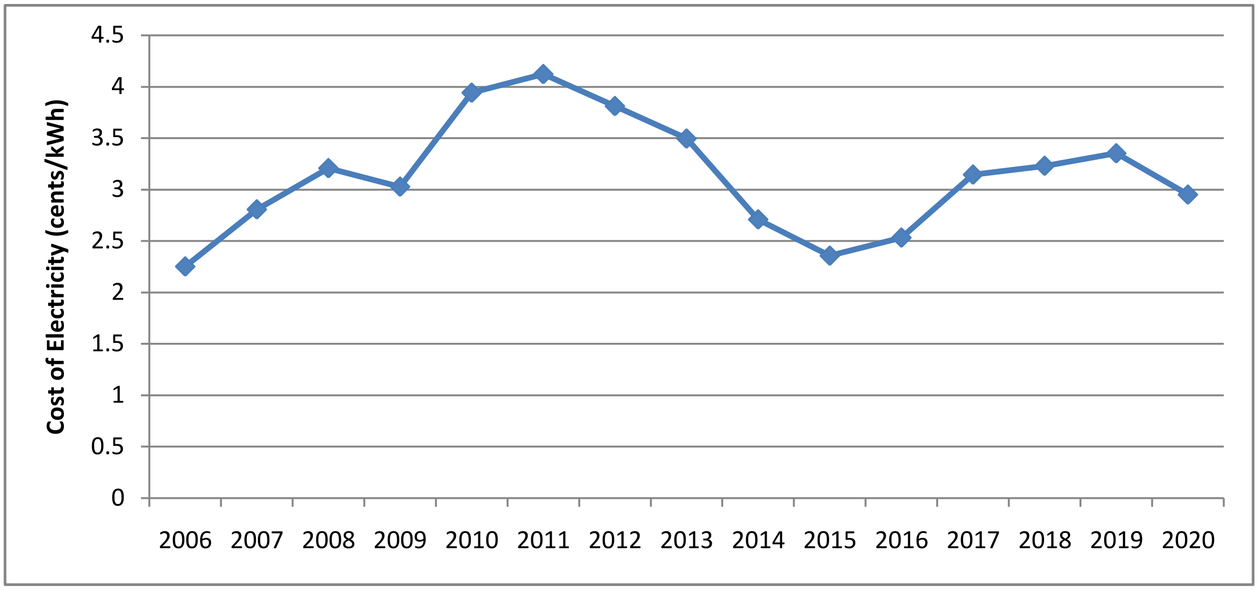



**Figure 43 -** Case Study II: Annual cost of electricity (COE) for the entire study period (2006-2020). All costs are expressed in terms of 2006 Canadian dollars.

As shown in Figure 43, the COE varies significantly throughout the span of the study period. The COE ranges from a minimum of 2.252 cents/kWh in 2006, to a maximum of 4.12 cents/kWh in 2012. The variability associated with the COE in any particular year is dependent on all the factors that are considered in the total expenditure for that year. For instance, the high COE observed in year 2012 is due to a large amount of money being spent on fuel, construction of new power plants, and refurbishing nuclear units, relative to how much electricity is generated. Similarly, the low COE experienced in 2006 is due to the low capital expenditure spent relative to the electricity generated.

## 4.6.4 Carbon Dioxide Emissions

Annual $CO_2$ emissions from the entire fleet are presented in Figure 44. The total $CO_2$ emissions over the study period amount to 359 Mt. Note that an annual $CO_2$ emissions limit of 20 Mt after the year 2011 was imposed in this case study, and hence it is expected that this case study will have lower $CO_2$ emissions compared to the base case.

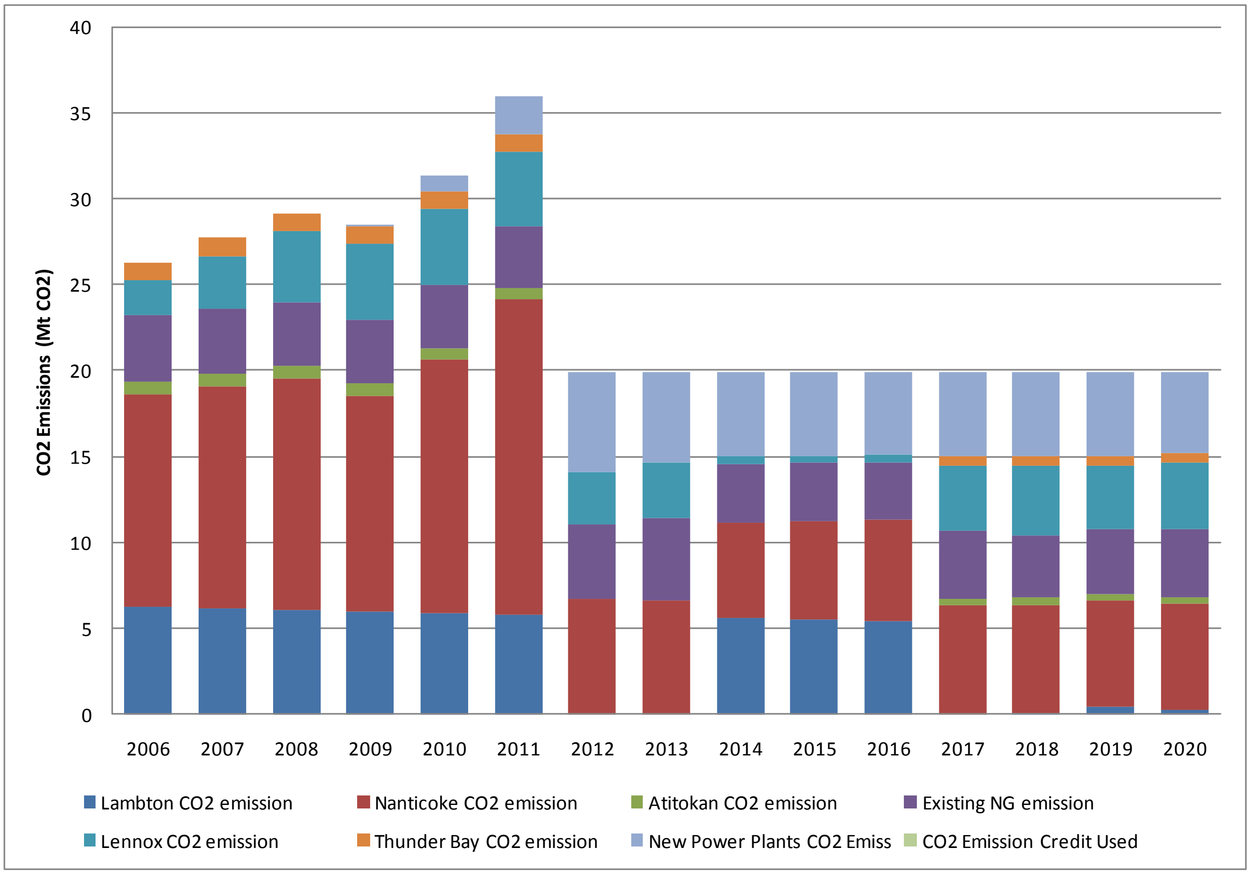



**Figure 44 -** Case Study II: Annual carbon dioxide emissions from entire fleet.

As can be seen in Figure 44, the annual $CO_2$ emissions from the entire fleet are relatively high during the years in which no $CO_2$ emission limits are imposed (2006 through 2011), and constant at 20 Mt after year 2011 when an annual $CO_2$ limit is imposed on the entire fleet.

The $CO_2$ emissions from the fleet increase from 2006 through 2011, reaching a peak of 36 Mt in 2011. As shown in Figure 44, the Nanticoke coal-fired generating station is the single largest source of $CO_2$

emissions during the years in which no emissions limits are imposed. In 2011, Nanticoke alone is responsible for 50.09 % of the $CO_2$ emissions generated from the entire fleet.

After the year 2011, the annual $CO_2$ emissions from the entire fleet remains constant at 20 Mt due to the annual $CO_2$ emissions imposed on the fleet.

## 4.7 Comparison of Case Studies

The following section presents a comparative analysis of the two case studies outlined in Sections 4.5 and 4.6. The comparative analysis is done based on differences in fleet structural, power production, economical expenditure, and environmental impacts.

The fleet structure for Case Study I and II differs notably. As can be seen in Table 23, in the base case (Case Study I), one PC power plant and five new NGCC power plants were built, whereas for the case study with $CO_2$ emission limits (Case Study II), three NGCC, two NGCC+CCS, and one nuclear power plant were built. There were no new coal-fueled supply technologies built in Case Study II.

**Table 23 -** Comparison of new power plants built for Case Study I and II. The table presents the type of technology, net capacity, and the year in which construction should commence.

| | Technology | Net Capacity (MW) | Start of construction | Total capacity (MW) |
|---|---|---|---|---|
| Case Study I | PC-31 | 526.5 | 2006 | 526.5 |
| | NGCC-22 | 1013 | 2006 | 5318.5 |
| | NGCC-31 | 759.8 | 2008 | |
| | NGCC-32 | 1519.6 | 2010 | |
| | NGCC-23 | 1519.5 | 2014 | |
| | NGCC-21 | 506.5 | 2016 | |
| Case Study II | NGCC21 | 506.5 | 2006 | 4305.5 |
| | NGCC32 | 1519.6 | 2007 | |
| | NGCC33 | 2279.4 | 2009 | |
| | NGCC21+CCS | 2279.4 | 2009 | 2711.7 |
| | NGCC31+CCS | 432.3 | 2009 | |
| | ACR-700 Nuclear Unit | 1406 | 2006 | 1406 |

In Case Study I, decision criteria were based on several parameters such as the construction capital costs, operation parameters, and fuel price forecasts. The optimal solution was found based on the imposed parameters and with no consideration for $CO_2$ emissions. It was not economically justified to implement any CCS systems for this case since there were no requirements to reduce $CO_2$ emissions.

For Case Study II, $CO_2$ emission constraints are imposed and the optimal solution involves considering the power plant technologies that meet $CO_2$ emission requirements. The optimizer has to be mindful of $CO_2$ emissions when choosing to build a new power plant. Unlike the base case, two NGCC plants were built with an integrated CCS system in Case Study II. Furthermore, no PC plants were built.

In regards to the existing coal power plants, there are several notable differences between the base case and Case Study II. These include the implementation of fuel-switching, retrofitting with CCS, and the power allocated from each power plant in order to meet demand.

Table 24 shows whether fuel-switching and CCS retrofitting was implemented for each existing coal power plant in the two cases studied.

**Table 24 –** Comparison of fuel-switching and CCS retrofit implementation between Case Study I and II.

| Power Plant | Fuel-Switching | | CCS Retrofit | |
|---|---|---|---|---|
| | Case Study 1 | Case Study 2 | Case Study 1 | Case Study 2 |
| Lambton | No | No | No | **Yes** |
| Nanticoke | No | **Yes** | No | No |
| Atikokan | No | **Yes** | No | No |
| Lennox | No | No | No | No |
| Thunder Bay | No | **Yes** | No | No |

As shown in Table 24, Nanticoke, Atikokan, and Thunder Bay power plants were fuel-switched for Case Study II, while none of the coal power plants were fuel-switched in the base case. This is because the capital costs and the fuel costs associated with switching an existing coal power plant to NG are considerable. The driving force behind fuel-switching is to lower $CO_2$ emissions and since there are no $CO_2$ emission constraints, no incentives exist to choose this option in the base case.

For the same reasons listed above, Lambton was retrofitted with a CCS system in 2018 for Case Study II but no CCS was implemented in Case Study I (Table 24). Once again, retrofitting a power plant with a CCS system is only justified when $CO_2$ emissions need to be reduced.

As shown in Figure 21 of Section 4.5.2, in the base case the power allocation from coal power plants is maximized in each year of the period studied. This implies that all coal power units are operational at maximum capacity in order to meet peak-load or base-load demand. The power allocation from coal power plants for Case Study II is shown in Figure 33 of Section 4.6.2. As can be seen from this figure, not all coal units are running at full capacity in Case Study II. While coal power plants were utilized to the maximum to meet demand in Case Study I, maximum coal power plant utilization was only employed from 2006-2011 for Case Study II. During these years, no annual $CO_2$ limits were imposed. After this time, annual $CO_2$ emissions are constrained for Case Study II, and coal power plants are utilized minimally. This is due to the high $CO_2$ emissions associated with using coal power plants that have no $CO_2$ mitigating technologies.

In Case Study II, maximum coal power plant utilization was employed from 2006-2011 to meet base-load and peak-load demand. From 2011-2020, coal power plants were utilized minimally to meet peak-load demand, and were not used at all to meet base-load demand. This is because in order to meet base-load demand, the coal plants would need to be run continuously which would generate high $CO_2$ emissions. For peak-load demand, however, the coal plants do not need to be used continuously but only need to be turned on during peak periods and $CO_2$ emissions associated with such operation are much lower. In order to compensate for the gap in power production created by not using coal power plants, other supply technologies were used in Case Study II to meet demand, such as NGCC+CCS, NGCC, and new nuclear.

In both the base case and Case Study II, the optimizer decided to maximize renewable energy production (maximum of 7,902 MW). This is because renewable energy is a clean and inexpensive supply source. For the base case the fact that renewable energy is a clean energy source is not the determining factor in choosing it, since there are no $CO_2$ emission limits, but it is rather its low-cost that is the motivation behind renewable energy utilization.

The long-term hydro imports discussed in Section 2.2.6 were not utilized in either of the case studies examined. This is because the optimizer determined that it would be more economically feasible to build other supply technologies rather than use long term hydroelectric imports from Ontario-Manitoba Interconnection project.

Table 25 presents a comparison of the total expenditure for Case Study I and Case Study II for the entire study period of 2006-2020.

**Table 25 –** Comparison of total expenditure (2006 $CAN billion) between Case Study I and II.

| | Total expenditure ( 2006 $CAN billion) | | |
|---|---|---|---|
| Expenditure | Case Study 1 : Base Case | Case Study II : 6% below 1990 levels | Difference (Case II – Case I) |
| Nuclear refurbishment | 11.97 | 11.97 | 0 |
| Capital for new power | 4.88 | 8.17 | 3.29 |
| Capital for fuel-switching | 0 | 0.1 | 0.1 |
| Fixed O&M of existing | 22.43 | 21.33 | -1.1 |
| Fixed O&M of new | 0.87 | 1.03 | 0.16 |
| Fuel | 25.22 | 30.34 | 5.12 |
| Variable O&M of existing | 5.58 | 5.07 | -0.51 |
| Variable O&M of new | 0.05 | 0.54 | 0.49 |
| Capital and O&M of CCS | 0 | 0.54 | 0.54 |
| **Total** | **70.99829** | **79.09674** | **8.09846** |

The cost of capital for new power plants is higher for Case Study II than the base case by $3.29 billion. This is because of the higher cost of building low-$CO_2$ emission facilities, such as NGCC+CCS. In particular, the cost of building a new nuclear plant is a major factor in the higher capital costs seen in Case Study II.

From Table 25, the cost of fuel is higher for Case Study II since more power plants using natural gas are employed in this case. Since the cost of natural gas is higher compared to the other fuel sources, the overall cost is higher for Case Study II.

Fixed and variable O&M costs of existing plants were lower for Case Study II compared to the base case. This is mainly due to the fact that the coal power plants in Case Study II are operated less frequently than in the base case. However, fixed and variable O&M costs for new plants were higher for Case Study II since operating costs of new plants, such as NGCC+CCS, are higher than for NGCCs with no CCS systems. Furthermore, the new power plants are utilized more in order to meet demand, and hence the associated O&M costs are higher.

From Sections 4.5.4 and 4.6.4, the total $CO_2$ produced for Case Study I and Case Study II is 525 Mt and 359 Mt respectively. Thus, there is a total of 166 Mt less $CO_2$ produced in Case Study II. This is a $CO_2$ reduction of approximately 32% for Case Study II when compared to the base case. From Table 25, the total expenditure for Case I is $70.99 billion and for Case II it is $79.09 billion, a difference of $8.1 billion. This amounts to an increase of 10.1% in cost. This amount represents the total additional investment required to meet a $CO_2$ target of 6% below 1990 levels after 2011 for Case Study II. Hence, the total cost associated with $CO_2$ reduction, per ton of $CO_2$, is $48.79 / ton $CO_2$ reduced.

The average cost of electricity for Case Study II is higher than for Case Study I. From Section 4.5.3 and 4.6.3, the cost of electricity for Case Study I is 2.804 cents/kWh and for Case Study II it is 3.129 cents/kWh. The higher COE is due to the increased cost associated with meeting the $CO_2$ limit for Case Study II.

Overall, mitigating $CO_2$ emissions is a cost intensive endeavour that results in increased overall costs, which have a direct effect on increasing the total COE costs. The higher costs of meeting $CO_2$ targets in Case Study II are based on various factors. Namely, costs increase due to: selection and construction of cleaner, less carbon-intensive supply technologies; cost of CCS; cost of fuel switching; and operation of more expensive supply technologies.

# Chapter 5

## 5.1 Conclusions

This project achieved the objective of developing a deterministic multi-period mixed-integer non-linear programming (MINLP) model that is able to realize the optimal mix of energy supply sources that meet current and future electricity demand, $CO_2$ emission targets, and lower the overall cost of electricity. This model was implemented in GAMS (General Algebraic Modeling System) using the ILOG CPLEX 10.1 solver.

The specific goals and deliverables that were accomplished as part of this thesis work are:

- A deterministic MINLP model was developed and implemented in GAMS.
- Detailed data was acquired on various supply options that were used as parameters for the model.
- The cost and feasibility of using carbon capture and storage in Ontario were examined.
- The model was applied to two case studies: a base case, and a case scenario in which Ontario's electricity sector must comply with annual $CO_2$ emissions of 20 Mt (6% below 1990 level) after year 2011. The relative impacts studied were based on economical, structural and environmental affects.

It should be noted that although this project was aimed at Ontario's future energy supply mix, it has been formulated in a way that allows its application to other regions or countries.

**MODEL FORMULATION**

Several conclusions and findings can be made in regards to the MINLP model formulation:

- The formulated MINLP mathematical model was linearized using exact linearization methods in order to avoid inherited computational difficulties of large convex non-linear models. This linearization was able to lower the computation expense while retaining the consistency of the solution.

- The objective function of the model was formulated with the aim of minimizing the net present value of the cost of electricity (COE) over a time horizon of 14 years. The formulation incorporated several time dependent parameters such as forecasted energy demand, fuel price variability, construction lead time, conservation initiatives, and increase in fixed operational and maintenance costs over time.

- The programmed GAMS model was executed and solved on an AMD Athlon 2.59 GHz, 2 GB RAM computer. Once executed, GAMS was able to find an optimal solution after a runtime of approximately 9 hours.

- Several GAMS/CPLEX solving options were considered in order to improve performance and reduce overall computational time. However, none of the options considered achieved this objective. The most effective strategy found to improve the overall performance and reduce the computation time was to reformulate the problem.

## CASE STUDIES

The main conclusions of the two case studies examined in this project are as follows:

### *Case Study I – Base Case*

- One PC power plant and five new NGCC power plants were built between 2006 and 2020. The total net capacity of all new NGCC and PC units was 5,318 MW and 526.5 MW respectively.

- No NGCC+CCS, IGCC+CCS, PC+CCS and IGCC were constructed during the time horizon considered.

- It was found that no economic justification existed to implement any CCS systems or fuel switching since there were no requirements to reduce $CO_2$ emissions.

- The majority of base-load demand was met through utilization of renewable, coal, and nuclear power. Peak-load demand was satisfied by various supply sources, including NGCC, renewable, coal, PC and existing NG and oil.

- Coal power plant usage was maximized in order to help meet the base-load and peak-load demand.

- Renewable energy production was utilized to its maximum of 7,902 MW during the entire time period studied.

- The total $CO_2$ emission over the study period amount to 525 Mt.

- The total expenditure for the entire study period was $79.10 billion. Moreover, the average COE for the base case was 2.804 cents/kWh.

***Case Study II – $CO_2$ Emissions 6% below 1990 levels by 2011***

- Three NGCC, two NGCC+CCS, and one nuclear power plant were built between 2006 and 2020. The total net capacity of new NGCC, NGCC+CCS, and nuclear power plants was 4,305.5 MW, 2,711.7 MW, and 1,406 MW respectively. There were no new coal-fueled supply technologies built in Case Study II.

- We are able to meet an annual $CO_2$ target of 20 Mt (6% below 1990 levels) after 2011. This target can be achieved by implementing a combination of fuel-switching, CCS retrofit, power balancing, and construction of low emitting supply technologies.

- Nanticoke, Atikokan, and Thunder Bay power plants were fuel-switched in years 2012, 2017, and 2017, respectively. The fuel-switching of these coal power plants was implemented in order to reduce the $CO_2$ emitted from these power plants. The optimizer determined that it was more economically feasible to fuel-switch the above mentioned coal power plants than to shut them down. The capital cost of fuel-switching these power stations is $10 million.

- It was determined that the option of retrofitting an existing coal power plant with a CCS system is a sound and economically feasible endeavour. In Case Study II, a CCS system was retrofitted in Lambton coal power plant in year 2018. The overall cost of implementing and operating this CCS system amount to $54 million.

- Maximum coal power plant utilization was employed from years 2006-2011 in order to meet base-load and peak-load demand. After year 2011, coal power plants were minimally operated to meet peak-load demand and were not used at all to meet base-load demand. Coal power plants were not utilized for base-load demand after year 2011 due to the high $CO_2$ emission. In order to compensate for the gap in power production created by not using coal power plants, other supply technologies were used in Case Study II to meet demand, such as NGCC+CCS, NGCC and new nuclear.

- The total $CO_2$ emission over the study period amounted to 359 Mt. This is a $CO_2$ reduction of approximately 32% when compared to the base case. The annual $CO_2$ emissions from the entire fleet remained constant at 20 Mt after the year 2011.
- The total expenditure for the entire study period was $79.10 billion. The total expenditure for Case Study II was approximately 10.1% higher than for the base case. The higher cost observed in Case Study II is due to the additional expenditure required to mitigate and meet the specified $CO_2$ limit. Fuel cost and capital expenditure for new power stations are the main two factors that drive the total cost of Case Study II up. The increased fuel cost is due to the operation of more expensive fuel sources such as natural gas. The increase in capital expenditure is due to the construction of more expensive, but low carbon-intensive, power plants such as NGCC+CSS and nuclear units.
- The total cost associated with reducing the $CO_2$ emissions to 6% below 1990 levels, per ton of $CO_2$, was $48.79 / ton $CO_2$ reduced.
- The average cost of electricity for Case Study II was higher than Case Study I. The COE for Case Study II was 3.129 cents/kWh, which is an increase of about 10.04% when compared to the base case. The higher COE was due to an increased cost associated with meeting the $CO_2$ limit for Case Study II.

## 5.2 Recommendations for Future Work

The multi-period optimization model developed in this thesis can be improved by pursuing the following recommendations:

1. The model can be reformulated from a deterministic model into a stochastic model. Reformulating the model into a stochastic multi-period framework would allow handling of probabilistic parameters. In reality, parameters such as electricity demand and fuel price fluctuations are random in nature and do not follow a deterministic path. However, the reformulation of the model into a stochastic framework may significantly increase the complexity of the model and inheritably complicate the computational time of the solution.

2. The developed model currently does not take into account the geological location of the new power plants being built. In future work, the model can be modified in order to incorporate the geographical location of the new power plants. The location of the new stations may directly affect both transmission losses and local distribution strategies.

3. The model could be improved by formulating an additional mathematical function that would allow the optimizer to design and map a complete pipe-line network for the CCS system. In order to achieve this, the geological map of a region can be divided into a zoning matrix. The path of the pipe-line network would be determined by several factors such as the cost of building a pipeline through that zone and the particular characteristics of the area.

4. Currently the formulated model is designed as a single objective function model which attempts to minimize the cost of electricity while meeting electricity demand and a specified annual $CO_2$ limit. The model can be reformulated into a multi-objective function that minimizes the total cost of electricity and $CO_2$ emission of the entire fleet simultaneously.

5. The fixed and variable O&M costs of the power stations considered in this thesis were assumed to remain constant over time. In reality, the O&M costs of power stations increase over time due to aging of the unit. In order to improve the results of the model, it is recommended that reliable time dependent O&M costs be found and used.

6. The model can be expanded by considering several additional pollutants such as NOx, $SO_2$, and Particulate Matter (PM). Specifying emission limits of additional pollutants may increase the size of the model significantly, and hence, increase the overall computational time.

7. The model may be expanded to include the option of importing and exporting electricity from neighbouring regions.

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# Appendix A

## Forecasted Demand by Chui et al. (2006)

**Table 26 -** Ontario's forecasted Annual Energy demand (GWh) for lower, median, and upper bound.

| **Year** | Median Forecast | Low Forecast with Mild Weather | High Forecast with Extreme Weather |
|---|---|---|---|
| 2005 | 155,781,368.95 | 152,430,691.17 | 159,771,847.64 |
| 2006 | 157,450,326.05 | 154,099,648.27 | 161,440,804.74 |
| 2007 | 159,147,655.42 | 155,796,977.64 | 163,138,134.10 |
| 2008 | 160,873,839.38 | 157,523,161.61 | 164,864,318.07 |
| 2009 | 162,629,368.48 | 159,278,690.71 | 166,619,847.17 |
| 2010 | 164,099,675.73 | 160,433,932.12 | 168,405,220.26 |
| 2011 | 165,590,567.28 | 161,601,881.19 | 170,220,944.69 |
| 2012 | 167,102,331.32 | 162,782,677.69 | 172,067,536.44 |
| 2013 | 168,635,260.05 | 163,976,462.96 | 173,945,520.25 |
| 2014 | 170,189,649.78 | 165,183,379.87 | 175,855,429.78 |
| 2015 | 171,653,218.74 | 166,292,646.22 | 177,569,292.72 |
| 2016 | 173,135,814.10 | 167,413,005.24 | 179,308,863.60 |
| 2017 | 174,637,683.20 | 168,544,567.85 | 181,074,528.04 |
| 2018 | 176,159,076.59 | 169,687,446.09 | 182,866,677.45 |
| 2019 | 177,700,248.10 | 170,841,753.11 | 184,685,709.11 |
| 2020 | 178,781,083.54 | 171,541,263.16 | 186,162,762.81 |
| 2021 | 179,871,646.49 | 172,244,970.28 | 187,657,541.15 |
| 2022 | 180,972,024.51 | 172,952,899.63 | 189,170,256.84 |
| 2023 | 182,082,305.94 | 173,665,076.57 | 190,701,125.11 |
| 2024 | 183,202,579.89 | 174,381,526.56 | 192,250,363.81 |
| 2025 | 184,332,936.31 | 175,102,275.25 | 193,818,193.36 |

**Table 27** - Ontario's forecasted annual peak-load demand (MW) for low, median, and upper bound.

| Year | Median Forecast | Low Forecast | High Forecast |
|---|---|---|---|
| 2005 | 26,183.23 | 25,469.63 | 27,027.89 |
| 2006 | 26,649.82 | 25,923.50 | 27,509.54 |
| 2007 | 27,132.88 | 26,393.39 | 28,008.17 |
| 2008 | 27,633.12 | 26,880.00 | 28,524.55 |
| 2009 | 28,151.33 | 27,384.09 | 29,059.48 |
| 2010 | 28,592.82 | 27,720.96 | 29,613.79 |
| 2011 | 29,047.56 | 28,065.74 | 30,188.37 |
| 2012 | 29,516.05 | 28,418.67 | 30,784.16 |
| 2013 | 29,998.81 | 28,780.00 | 31,402.13 |
| 2014 | 30,496.40 | 29,149.98 | 32,043.33 |
| 2015 | 30,972.45 | 29,494.21 | 32,629.86 |
| 2016 | 31,462.27 | 29,846.01 | 33,236.16 |
| 2017 | 31,966.36 | 30,205.59 | 33,863.08 |
| 2018 | 32,485.24 | 30,573.17 | 34,511.49 |
| 2019 | 33,019.45 | 30,948.96 | 35,182.33 |
| 2020 | 33,399.32 | 31,178.93 | 35,736.63 |
| 2021 | 33,787.05 | 31,412.01 | 36,306.48 |
| 2022 | 34,182.83 | 31,648.24 | 36,892.42 |
| 2023 | 34,586.86 | 31,887.68 | 37,495.01 |
| 2024 | 34,999.38 | 32,130.39 | 38,114.86 |
| 2025 | 35,420.59 | 32,376.42 | 38,752.58 |

**Table 28 -** Ontario's forecasted annual base-load demand (MW) for low, median, and upper bound.

| **Year** | Median Forecast | Low Forecast | High Forecast |
|---|---|---|---|
| 2005 | 12,144.65 | 12,144.65 | 12,144.65 |
| 2006 | 12,294.92 | 12,294.92 | 12,294.92 |
| 2007 | 12,445.18 | 12,445.18 | 12,445.18 |
| 2008 | 12,595.45 | 12,595.45 | 12,595.45 |
| 2009 | 12,745.71 | 12,745.71 | 12,745.71 |
| 2010 | 12,869.64 | 12,843.23 | 12,895.98 |
| 2011 | 12,993.58 | 12,940.75 | 13,046.24 |
| 2012 | 13,117.51 | 13,038.27 | 13,196.51 |
| 2013 | 13,241.44 | 13,135.79 | 13,346.77 |
| 2014 | 13,365.37 | 13,233.31 | 13,497.04 |
| 2015 | 13,480.51 | 13,322.01 | 13,629.76 |
| 2016 | 13,595.64 | 13,410.70 | 13,762.48 |
| 2017 | 13,710.78 | 13,499.40 | 13,895.19 |
| 2018 | 13,825.91 | 13,588.10 | 14,027.91 |
| 2019 | 13,941.05 | 13,676.80 | 14,160.63 |
| 2020 | 14,020.92 | 13,730.12 | 14,266.96 |
| 2021 | 14,100.78 | 13,783.45 | 14,373.29 |
| 2022 | 14,180.65 | 13,836.77 | 14,479.63 |
| 2023 | 14,260.52 | 13,890.10 | 14,585.96 |
| 2024 | 14,340.39 | 13,943.42 | 14,692.29 |
| 2025 | 14,420.26 | 13,996.75 | 14,798.62 |

# Appendix B

## Natural Gas & Coal Price Forecast from NEB

**Table 29 –** Forecasted NG prices from National Energy Board (NEB). The presented data is based on two scenarios: a supply-plus and a techno-vert case (Naini et al., 2005).

| Year | NG Price (1986C$/GJ) | |
|---|---|---|
| | Supply-Plus | Techno-Vert |
| 2005 | 4.77 | 5.02 |
| 2006 | 4.76 | 5.08 |
| 2007 | 4.76 | 5.14 |
| 2008 | 4.75 | 5.21 |
| 2009 | 4.74 | 5.27 |
| 2010 | 4.72 | 5.33 |
| 2011 | 4.7 | 5.31 |
| 2012 | 4.69 | 5.29 |
| 2013 | 4.67 | 5.23 |
| 2014 | 4.65 | 5.18 |
| 2015 | 4.63 | 5.15 |
| 2016 | 4.62 | 5.12 |
| 2017 | 4.6 | 5.07 |
| 2018 | 4.57 | 5.03 |
| 2019 | 4.53 | 4.99 |
| 2020 | 4.48 | 4.95 |
| 2021 | 4.43 | 4.91 |
| 2022 | 4.39 | 4.86 |
| 2023 | 4.35 | 4.82 |
| 2024 | 4.3 | 4.77 |
| 2025 | 4.25 | 4.73 |

**Table 30 -** Coal price forecast from National Energy Board (NEB). Costs are expressed in terms of 1986 Canadian dollars (Naini et al., 2005).

| Year | Coal Price (1986C$/GJ) |
|---|---|
| 2005 | 1.21 |
| 2006 | 1.2 |
| 2007 | 1.18 |
| 2008 | 1.17 |
| 2009 | 1.16 |
| 2010 | 1.15 |
| 2011 | 1.14 |
| 2012 | 1.13 |
| 2013 | 1.11 |
| 2014 | 1.1 |
| 2015 | 1.09 |
| 2016 | 1.09 |
| 2017 | 1.09 |
| 2018 | 1.09 |
| 2019 | 1.09 |
| 2020 | 1.09 |
| 2021 | 1.09 |
| 2022 | 1.09 |
| 2023 | 1.09 |
| 2024 | 1.09 |
| 2025 | 1.09 |

# Appendix C

## GAMS Model

```
$title  A Multiperiod Optimization Model for Energy Planning with CO2 Emission Considerations

$ontext

Version: 1.5.15
Date: March, 08,2007

Author: Hamid Mirza


$offtext

$call =xls2gms @"C:\Model Data\xls2gms_data.txt"

*
*.. list all sets
*
 Set
i   power stations /
$include C:\Model Data\Model Input\set_i.inc
/
F  Fossil/
$include C:\Model Data\Model Input\set_F.inc
/
NG  Existing Natural Gas /
$include C:\Model Data\Model Input\set_NG.inc
/
ENuc  Existing Nuclear stations/
$include C:\Model Data\Model Input\set_ENuc.inc
/
H  Existing Hydro/
$include C:\Model Data\Model Input\set_H.inc
/
W  Existing Wind/
$include C:\Model Data\Model Input\set_W.inc
/

*==========================================
*=== Subsets for existing power plants
*==========================================
L(F)  Lambton /
$include C:\Model Data\Model Input\set_L.inc
/
NN(F)  Nanticoke /
$include C:\Model Data\Model Input\set_NN.inc
/
A(F)   Atitokan /
$include C:\Model Data\Model Input\set_A.inc
/
LN(F)  Lennox /
$include C:\Model Data\Model Input\set_LN.inc
/
TB(F)  Thunder Bay /
$include C:\Model Data\Model Input\set_TB.inc
/
```

```
*===========================================
*=== Set of new power plants
*===========================================
NFP  New plant fossil /
$include C:\Model Data\Model Input\set_NFP.inc
/
NFPC  New plant fossil with capture/
$include C:\Model Data\Model Input\set_NFPC.inc
/
NNuc New nuclear /
$include C:\Model Data\Model Input\set_NNuc.inc
/
Impo New Imports /
$include C:\Model Data\Model Input\set_Impo.inc
/

*===========================================
*=== Subsets of new power plants
*===========================================
PP1(NFP)  PC 1 without capture/
$include C:\Model Data\Model Input\set_PP1.inc
/
PP2(NFP)  PC 2 without capture/
$include C:\Model Data\Model Input\set_PP2.inc
/
PP3(NFP)  PC 3 without capture /
$include C:\Model Data\Model Input\set_PP3.inc
/
PI1(NFP) IGCC 1 without capture /
$include C:\Model Data\Model Input\set_PI1.inc
/
PI2(NFP) IGCC 2 without capture /
$include C:\Model Data\Model Input\set_PI2.inc
/
PI3(NFP) IGCC 3 without capture /
$include C:\Model Data\Model Input\set_PI3.inc
/
PN1(NFP) NGCC 1 without capture /
$include C:\Model Data\Model Input\set_PN1.inc
/
PN2(NFP) NGCC 2 without capture /
$include C:\Model Data\Model Input\set_PN2.inc
/
PN3(NFP) NGCC 3 without capture /
$include C:\Model Data\Model Input\set_PN3.inc
/
PC1(NFPC)  PC 1 with capture/
$include C:\Model Data\Model Input\set_PC1.inc
/
PC2(NFPC)  PC 2 with capture/
$include C:\Model Data\Model Input\set_PC2.inc
/
PC3(NFPC)  PC 3 with capture /
$include C:\Model Data\Model Input\set_PC3.inc
/
IIC1(NFPC) IGCC 1 with capture /
$include C:\Model Data\Model Input\set_IIC1.inc
/
IIC2(NFPC) IGCC 2 with capture /
$include C:\Model Data\Model Input\set_IIC2.inc
/
IIC3(NFPC) IGCC 3 with capture /
$include C:\Model Data\Model Input\set_IIC3.inc
/
NC1(NFPC) NGCC 1 with capture /
```

```
$include C:\Model Data\Model Input\set_NC1.inc
/
NC2(NFPC) NGCC 2 with capture /
$include C:\Model Data\Model Input\set_NC2.inc
/
NC3(NFPC) NGCC 3 with capture /
$include C:\Model Data\Model Input\set_NC3.inc
/


*=========================================
*=== Other sets
*=========================================
j   fuels /
$include C:\Model Data\Model Input\set_j.inc
/
k   capture process /
$include C:\Model Data\Model Input\set_k.inc
/
s   sequestration location /
$include C:\Model Data\Model Input\set_s.inc
/
t   time horizon /
$include C:\Model Data\Model Input\set_t.inc
/
ldc   Load Duration Curve ldc /
$include C:\Model Data\Model Input\set_ldc.inc
/
;

alias (t, tc);

*===============================Scalar===================================
*=======================================================================

 Scalar R       allowable electricity increment /0.01/;
 Scalar Lower    ACF lower bound /0.1/;
 Scalar perCCS   percent CO2 capture /0.9/;
 Scalar MaxCapRetro   maximum energy requirement for capture (MWh per yr)/1000000000/;
 Scalar M       big number used in CO2 emission constraints /1E11/;
 Scalar Ms      big number used in linearization for CCS retrofit /1E14/;
 Scalar Mp      big number used in linearization for new plant w cap /1E14/;
 Scalar loss     Transmission and distribution loss factor /0/;
 Scalar Optime   Maximum operation time in a year is 8760 hours /8760/;

*===========================Model Parameters=============================
*=======================================================================

*=== Net Capacity for Existing power stations (MW)
*
 Table NetCapF(F,t)        Net Capacity for Existing Coal Power Stations(MW)

$include C:\Model Data\Model Input\data_NetCapF.inc
;
 Parameter NetCapNG(NG)      Net Capacity for Existing NG Power Stations(MW)
/
$include C:\Model Data\Model Input\data_NetCapNG.inc
/;
 Table NetCapENuc(ENuc,t)     Net Capacity for Existing Nuclear Power Stations(MW)
$include C:\Model Data\Model Input\data_NetCapENuc.inc
;
 Parameter NetCapH (H)       Net Capacity for Existing Hydro Power Stations(MW)
/
$include C:\Model Data\Model Input\data_NetCapH.inc
/;
 Parameter NetCapW(W)        Net Capacity for Existing Wind Power Stations(MW)
```

```
/
$include C:\Model Data\Model Input\data_NetCapW.inc
/;

*
*===Net Capacity for New Power Plants (MW)
*
 Table NetCapNFP(NFP,tc,t)  Net Capacity for New Fossil Fuel Power Plant WITHOUT Capture (MW)
$include C:\Model Data\Model Input\data_NetCapNFP.inc
;
 Table NetCapNFPC(NFPC,tc,t)     Net Capacity for New Fossil Fuel Power Plant WITH Capture (MW)
$include C:\Model Data\Model Input\data_NetCapNFPC.inc
;
 Table NetCapNNuc(NNuc,tc,t)     Net Capacity for New Nuclear Power Plant (MW)
$include C:\Model Data\Model Input\data_NetCapNNuc.inc
;
 Table NetCapImpo(Impo,tc,t)  Net Capacity for New Imports (MW)
$include C:\Model Data\Model Input\data_NetCapImpo.inc
;
*
*===Gross Capacity for Existing power stations (MW)
*
 Parameter GrossCapF(F)       Gross capacity for Existing Coal Power Plants(MW)
/
$include C:\Model Data\Model Input\data_GrossCapF.inc
/;
 Parameter GrossCapNG(NG)      Gross capacity for Existing NG Power Plants(MW)
/
$include C:\Model Data\Model Input\data_GrossCapNG.inc
/;
 Table GrossCapENuc(ENuc,t)    Gross capacity for Existing Nuclear Power Plants(MW)
$include C:\Model Data\Model Input\data_GrossCapENuc.inc
;
 Parameter GrossCapH(H)       Gross capacity for Existing Hydro Power Plants(MW)
/
$include C:\Model Data\Model Input\data_GrossCapH.inc
/;
 Parameter GrossCapW(W)       Gross capacity for Existing Wind Power Plants(MW)
/
$include C:\Model Data\Model Input\data_GrossCapW.inc
/;

*
*===Gross Capacity  for New Power Plants (MW)
*
 Parameter GrossCapNFP(NFP)  Gross Capacity for New Fossil Fuel Power Plant WITHOUT Capture (MW)
/
$include C:\Model Data\Model Input\data_GrossCapNFP.inc
/;
 Parameter GrossCapNFPC(NFPC)     Gross Capacity for New Fossil Fuel Power Plant WITH Capture (MW)
/
$include C:\Model Data\Model Input\data_GrossCapNFPC.inc
/;
 Parameter GrossCapNNuc(NNuc)     Gross Capacity for New Nuclear Power Plant (MW)
/
$include C:\Model Data\Model Input\data_GrossCapNNuc.inc
/;
 Parameter GrossCapImpo(Impo)  Gross Capacity for New Imports (MW)
/
$include C:\Model Data\Model Input\data_GrossCapImpo.inc
/;

*
*=== Heat rate for Existing Power Plants (GJ per MWh)
*
 Table  HeatrF(F,j)     Heat Rate for Existing Coal Power Stations (GJ per MWh)
```

```
$include C:\Model Data\Model Input\data_HeatrF.inc
;
 Parameter  HeatrNG(NG)     Heat Rate for Existing NG Power Stations (GJ per MWh)
/
$include C:\Model Data\Model Input\data_HeatrNG.inc
/;
 Parameter  HeatrENuc(ENuc)     Heat Rate for Existing Nuclear Power Stations (GJ per MWh)
/
$include C:\Model Data\Model Input\data_HeatrENuc.inc
/;
 Parameter  HeatrH(H)     Heat Rate for Existing Hydor Power Stations (GJ per MWh)
/
$include C:\Model Data\Model Input\data_HeatrH.inc
/;
 Parameter  HeatrW(W)     Heat Rate for Existing Wind Power Stations (GJ per MWh)
/
$include C:\Model Data\Model Input\data_HeatrW.inc
/;

*
*=== Heat rate for NEW Power Plants (GJ per MWh)
*
 Parameter  HeatrNFP(NFP)     Heat Rate for New Fossil Fuel Power Stations WITHOUT Capture(GJ per MWh)
/
$include C:\Model Data\Model Input\data_HeatrNFP.inc
/;
 Parameter  HeatrNFPC(NFPC)   Heat Rate for New Fossil Fuel Power Stations WITH Capture(GJ per MWh)
/
$include C:\Model Data\Model Input\data_HeatrNFPC.inc
/;
 Parameter  HeatrNNuc(NNuc)     Heat Rate for New Nuclear Power Stations (GJ per MWh))
/
$include C:\Model Data\Model Input\data_HeatrNNuc.inc
/;
 Parameter  HeatrImpo(Impo)     Heat Rate for New Imports (GJ per MWh))
/
$include C:\Model Data\Model Input\data_HeatrImpo.inc
/;

*
*=== Fixed O&M cost ($ per MW) for Existing power stations
*
 Table  FixOprF(F,j)       Fixed operational cost for Existing Coal Power Plants ($ per MW)
$include C:\Model Data\Model Input\data_FixOprF.inc
;
 Parameter  FixOprENuc(ENuc)    Fixed Operation cost for existing Nuclear Power Stations($ per MW)
/
$include C:\Model Data\Model Input\data_FixOprENuc.inc
/;
 Parameter  FixOprNG(NG)     Fixed Operation cost for existing Natural Gas Power Stations ($ per MW)
/
$include C:\Model Data\Model Input\data_FixOprNG.inc
/;
 Parameter  FixOprH(H)     Fixed Operation cost for existing Natural Gas Power Stations ($ per MW)
/
$include C:\Model Data\Model Input\data_FixOprH.inc
/;
 Parameter  FixOprW(W)     Fixed Operation cost for existing Wing Stations ($ per MW)
/
$include C:\Model Data\Model Input\data_FixOprW.inc
/;
*
*=== Variable O&M cost ($ per MWh) for Existing power stations
*
 Table  VarOprF(F,j)       Variable operational cost for Existing Coal Power Plants ($ per MWh)
$include C:\Model Data\Model Input\data_VarOprF.inc
```

```
;
 Parameter  VarOprNG(NG)     Variable Operation cost for Existing Natural Gas Power Stations ($ per MWh)
/
$include C:\Model Data\Model Input\data_VarOprNG.inc
/;
 Parameter  VarOprENuc(ENuc)   Variable Operation cost for Existing Nuclear Power Stations ($ per MWh)
/
$include C:\Model Data\Model Input\data_VarOprENuc.inc
/;
 Parameter  VarOprH(H)   Variable Operation cost for Existing Nuclear Power Stations ($ per MWh)
/
$include C:\Model Data\Model Input\data_VarOprH.inc
/;
 Parameter  VarOprW(W)   Variable Operation cost for Existing Wind Power Stations ($ per MWh)
/
$include C:\Model Data\Model Input\data_VarOprW.inc
/;

*
*=== Retrofit Cost ($M20 per 1000 MW) for Coal power stations
*
 Parameter  RcostF(F)       Retrofit cost factor due to fuel switching($M20 per 1000 MW)
/
$include C:\Model Data\Model Input\data_RcostF.inc
/;

*
*.. CO2 emissions (tonne per MWh) for Existing fossil stations
*
 Table  CO2F(F,j) CO2 emission from Existing Coal Power Plant (tonne per MWh)
$include C:\Model Data\Model Input\data_CO2F.inc
;
 Parameter  CO2NG(NG) CO2 emission from Existing NG Power Plant (tonne per MWh)
/
$include C:\Model Data\Model Input\data_CO2NG.inc
/;

*
*=== Capital cost and Cash Flow($ per MW) for New Plants

 Table CcostNFP(NFP,tc,t) Capital Cost for New Fossil Fuel Power Plant WITHOUT Capture ($ per MW)
$include C:\Model Data\Model Input\data_CcostNFP.inc
;
 Table CcostNFPC(NFPC,tc,t) Capital Cost for New Fossil Fuel Power Plant WITH Capture ($ per MW)
$include C:\Model Data\Model Input\data_CcostNFPC.inc
;
 Table CcostNNuc(NNuc,tc,t) Capital Cost for New Nuclear Power Plant ($ per MW)
$include C:\Model Data\Model Input\data_CcostNNuc.inc
;
 Table CcostImpo(Impo,tc,t) Capital Cost for New Imports ($ per MW)
$include C:\Model Data\Model Input\data_CcostImpo.inc
;

*
*=== Annual Capacity Factor (ACF) for Existing Power Stations
*
 Parameter  ACFF(F)       Annual Capacity Factor for Existing Coal Power Plants
/
$include C:\Model Data\Model Input\data_ACFF.inc
/;
 Parameter  ACFNG(NG)     Annual Capacity Factor for Existing Natural Gas Power Stations
/
$include C:\Model Data\Model Input\data_ACFNG.inc
/;
 Parameter  ACFENuc(ENuc)   Annual Capacity Factor for Existing Nuclear Power Stations
/
```

```
$include C:\Model Data\Model Input\data_ACFENuc.inc
/;
 Parameter  ACFH(H)   Annual Capacity Factor for Existing Nuclear Power Stations
/
$include C:\Model Data\Model Input\data_ACFH.inc
/;
 Parameter  ACFW(W)   Annual Capacity Factor for Existing Wind Power Stations
/
$include C:\Model Data\Model Input\data_ACFW.inc
/;

*
*=== Annual Capacity Factor (ACF) for New Power stations
*
 Parameter ACFNFP(NFP) Annual Capacity Factor for new Fossil Fuel Power Without Capture
/
$include C:\Model Data\Model Input\data_ACFNFP.inc
/;
 Parameter ACFNFPC(NFPC) Annual Capacity Factor for new Fossil Fuel Power Without Capture
/
$include C:\Model Data\Model Input\data_ACFNFPC.inc
/;
 Parameter ACFNNuc(NNuC) Annual Capacity Factor for new nuclear
/
$include C:\Model Data\Model Input\data_ACFNNuc.inc
/;
 Parameter ACFImpo(Impo) Annual Capacity Factor for Imports
/
$include C:\Model Data\Model Input\data_ACFImpo.inc
/;

*
*=== Fixed operational cost ($ per MW) for NEW Power Plants
*
 Parameter FixOprNFP(NFP) Fixed O&M cost for NEW fossil fuel power plants without CO2 Capture ($ per MW)
/
$include C:\Model Data\Model Input\data_FixOprNFP.inc
/;
 Parameter FixOprNFPC(NFPC) Fixed O&M cost for NEW fossil fuel power plants with CO2 Capture ($ per MW)
/
$include C:\Model Data\Model Input\data_FixOprNFPC.inc
/;
 Parameter FixOprNNuc(NNuc) Fixed O&M cost (including fuel cost) for NEW nuclear ($ per MW)
/
$include C:\Model Data\Model Input\data_FixOprNNuc.inc
/;
 Parameter FixOprImpo(Impo) Fixed O&M cost for NEW Out-of-Province Imports ($ per MW)
/
$include C:\Model Data\Model Input\data_FixOprImpo.inc
/;
*
*=== Variable operational cost ($ per MWh) NEW Power Plant without capture
*
parameter VarOprNFP(NFP) Variable O&M cost for new fossil fuel power plants with CO2 Capture ($ per MWh)
/
$include C:\Model Data\Model Input\data_VarOprNFP.inc
/;

 parameter VarOprNFPC(NFPC) Variable O&M cost for new fossil fuel power plants with CO2 Capture ($ per MWh)
/
$include C:\Model Data\Model Input\data_VarOprNFPC.inc
/;

 parameter VarOprNNuc(NNuc) Variable O&M cost (including fuel cost) for new nuclear ($ per MWh)
/
$include C:\Model Data\Model Input\data_VarOprNNuc.inc
```

```
/;

 parameter VarOprImpo(Impo) Variable O&M cost for new Out-of-Province Imports ($ per MWh)
/
$include C:\Model Data\Model Input\data_VarOprImpo.inc
/;

*===CO2 emissions (tonne per MWh) from New Fossil Fuel Power Plants
*
 parameter CO2NFP(NFP) CO2 emissions from New Fossil Power Plant without capture (tonne per MWh)
/
$include C:\Model Data\Model Input\data_CO2NFP.inc
/;

 parameter CO2NFPC(NFPC) CO2 emissions from New Fossil Power Plant without capture(tonne per MWh)
/
$include C:\Model Data\Model Input\data_CO2NFPC.inc
/;

*
*=== Carbon capture and storage cost ($ per tonne CO2 capture)
*
 parameter  ccsF(F) ccs cost for  existing Fossil Fuel Power Plant  ($ per tonne CO2 capture)
/
$include C:\Model Data\Model Input\data_ccsF.inc
/;
 parameter  ccsNFPC(NFPC) ccs cost for new Fossil Fuel Power Plant with capture ($ per tonne CO2 capture)
/
$include C:\Model Data\Model Input\data_ccsNFPC.inc
/;

*.. Sequestration Cost for Existing Fossil Stations($ per tonne CO2 storage)
*
 Table  seqF(F,s) sequestration cost for Existing Coal-Fired Power plants ($ per tonne CO2 storage)
$include C:\Model Data\Model Input\data_seqF.inc
;

*=== Sequestration Cost for new power stations WITH capture process ($ per tonne CO2 storage)
*
 Table seqNFPC(NFPC,s) sequestration cost for New Fossil Power Plant with capture ($ per tonne CO2 storage)
$include C:\Model Data\Model Input\data_seqNFPC.inc
;

*=== Elec required for CO2 capture for Existing Coal-fired power plants

 Table  EreqF(F,j)  Elec required for CO2 capture in Existing Coal-Fired Power Plant (MWh per tonne CO2 capture)
$include C:\Model Data\Model Input\data_EreqF.inc
;

*
*=== Forecasted price of Coal and Natural Gas ($ per GJ)
*
Table FuelPrice(j,t) Forecasted Coal and Natural Gas prices ($ per GJ)
$include C:\Model Data\Model Input\data_FuelPrice.inc
;
* Forecasted price of Coal and NG ($ per GJ) - These values are the same as the ones found in
* table FuelPrice(j,t). The only diff is that the data is in a Parameter format.
*
 parameter  Pcoal(t) Forecasted Coal Price ($ per GJ)
/
$include C:\Model Data\Model Input\data_Pcoal.inc
/;
 parameter  NGcost(t) Forecasted Natural Gas Price ($ per GJ)
/
$include C:\Model Data\Model Input\data_NGcost.inc
/;
```

```
*
* CO2 Emission Limits for Entire Fleet Each Year (tonnes per year)
*
  parameter  CO2Limit(t) CO2 Emission Limits for Entire Fleet each year
/
$include C:\Model Data\Model Input\data_CO2Limit.inc
/;
*
* Carbon Emission Credit Cost ($ per tonnes CO2)
*
  parameter  CreditCost(t) Cost of buying CO2 Emission Credits ($ per tonne CO2)
/
$include C:\Model Data\Model Input\data_CreditCost.inc
/;

*  Demand Each year (MW per year)
*
  Table  CapDemand(ldc,t) Capacity demand each year (MW per year)
$include C:\Model Data\Model Input\data_CapDemand.inc
;

  Table  GenDemand(ldc,t) Generating demand each year (MWh per year)
$include C:\Model Data\Model Input\data_GenDemand.inc
;

  Table  Rconstraint(F,tc,t) Generating demand each year (MWh per year)
$include C:\Model Data\Model Input\data_Rconstraint.inc
;
 Table Timeldc(ldc,t)   Operation time for each segment of ldc
$include "C:\Model Data\Model Input\data_Timeldc.inc"
;

* Energy savings from Conservation strategy in Ontario (MW per year)
*
  parameter  Conservation(t) Total electricity savings from conservation strategies (MW per year)
/
$include C:\Model Data\Model Input\data_Conservation.inc
/;

Table yh
$include "C:\Model Data\Model Input\data_yh.inc"
;
Table yw
$include "C:\Model Data\Model Input\data_yw.inc"
;
Table yng
$include "C:\Model Data\Model Input\data_yng.inc"
;
Table yENuc
$include "C:\Model Data\Model Input\data_yENuc.inc"
;

$ontext
  parameter  UpperNFP(NFP)
/
$include C:\Model Data\Model Input\data_UpperNFP.inc
/;
  parameter  UpperNFPC(NFPC)
/
$include C:\Model Data\Model Input\data_UpperNFPC.inc
/;
  parameter  UpperNNuc(NNuc)
/
$include C:\Model Data\Model Input\data_UpperNNuc.inc
/;
```

```
 parameter  UpperImpo(Impo)
/
$include C:\Model Data\Model Input\data_UpperImpo.inc
/;
$offtext

*.. list all variables
*

Variables
 cost objective function

 MWred(t) total energy required for capture process on all fossil stations during period t

 PowerActiveRetro(F,t)

*---POSITIVE VARIABLES---

 Credit(t) Amount of CO2 subtracted from emission cap (during period t) due to Carbon Credit Purchase

 EF(F,ldc,t)       adjusted elec generation for Existing fossil power stations during period t (MWh per year)

 EENuc(ENuc,ldc,t)  adjusted elec generation for nuclear power plants during period t (MWh per year)
 EH(H,ldc,t)       adjusted elec generation for hydro power plants during period t (MWh per year)
 EW(W,ldc,t)       adjusted elec generation for wind power plants during period t (MWh per year)
 ENG(NG,ldc,t)      adjusted elec generation for natural gas power plants during period t (MWh per year)

 ENFP(NFP,ldc,t)     elec generation for PC during period t (MWh per year)
 ENFPC(NFPC,ldc,t)   elec generation for PC with capture during period t (MWh per year)
 ENNuc(NNuc,ldc,t)   elec generation for new nuclear during period t (MWh per year)
 EImpo(Impo,ldc,t)   elec generation for new Imports during period t (MWh per year)

 EFj(F,j,ldc,t)      adjusted elec generation for Existing fossil power stations using j fuel during period t (MWh per year)

 EkFj(F,j,k,ldc,t)     electricity required for capture process in F(MWh per year)

 gamaF(F,j,k,ldc,t)       Linearized variable = EFj * zF =  (MWh per year)

 CO2F1(t) Lambton CO2 emissions during period t
 CO2F2(t) Nanticoke CO2 emissions during period t
 CO2F3(t) Atitokan CO2 emissions during period t
 CO2F5(t) Lennox CO2 emissions during period t
 CO2F6(t) Thunder Bay CO2 emissions during period t
 CO2F7(t) Existing NG station CO2 emissions during period t
 CO2P(t)  CO2 Emissions From New Power Plants during period t

 XF(F,j,t)     fuel selection for existing fossil fuel power plant

 yNFP(NFP,tc)  decision whether to build a NEW fossil fuel without capture
 yNFPC(NFPC,tc) decision whether to build a NEW fossil fuel with capture
 yNNuc(NNuc,tc) decision either to build a new nuclear power plant
 yImpo(Impo,tc) decision whether to Import electricity

 zF(F,j,k,t)    decision whether to put a Carbon Capture on existing fossil fuel power plant

 retro(F,tc);

Binary variable XF,yNFP,yNFPC,yNNuc,yImpo,zF,retro;

Positive Variables EF,EENuc,EH,EW,ENG,ENFP,ENFPC,ENNuc,EImpo,EFj,EkFj,gamaF,
             CO2F1,CO2F2,CO2F3,CO2F5,CO2F6,CO2P,MWred,PowerActiveRetro,Credit;

Equations
 totcost    total annual cost  ($ per year)

 totMWh(ldc,t)
```

```
 swiL(F,t),gas1(t),gas2(t),gas3(t),gas4(t)

 epF(F,j,t),epENuc(ENuc,t),eph(h,t),epw(w,t),epng(ng,t)
 epF2(F,j,t),epENuc2(ENuc,t)

 totEkF(F,j,k,ldc,t)

 c1(F,j,k,ldc,t)

 f1(F,t),w1(F,j,t),z1(F,k,t)

 conF1(F,j,k,ldc,t),conF2(F,j,k,ldc,t),conF3(F,j,k,ldc,t)

 startNFP(NFP),startNFPC(NFPC),startNNuc(NNuc),startImpo(Impo)

retro1(F,t),retro2(F,t),retro3(F)
;

*============================OBJECTIVE FUNCTION============================
*==========================================================================
*
* Fixed O&M cost for existing power plants
totcost.. cost =e= (sum((F,j,t),XF(F,j,t)*FixOprF(F,j)*GrossCapF(F))+
              sum((NG,t),yNG(NG,t)*FixOprNG(NG)*GrossCapNG(NG))+
              sum((ENuc,t),yENuc(ENuc,t)*FixOprENuc(ENuc)*GrossCapENuc(Enuc,t))+
              sum((H,t),yH(H,t)*FixOprH(H)*GrossCapH(H))+
              sum((W,t),yw(W,t)*FixOprW(W)*GrossCapW(W))+

* Variable O&M cost for existing power plants
              sum((F,j,ldc,t),EFj(F,j,ldc,t)*Timeldc(ldc,t)*VarOprF(F,j))+
              sum((NG,ldc,t),ENG(NG,ldc,t)*Timeldc(ldc,t)*VarOprNG(NG))+
              sum((ENuc,ldc,t),EENuc(ENuc,ldc,t)*Timeldc(ldc,t)*VarOprENuc(ENuc))+
              sum((H,ldc,t),EH(H,ldc,t)*Timeldc(ldc,t)*VarOprH(H))+
              sum((W,ldc,t),EW(W,ldc,t)*Timeldc(ldc,t)*VarOprW(W))+

* Fuel Cost for existing coal and natural gas power plants
              sum((F,j,ldc,t), EFj(F,j,ldc,t)*Timeldc(ldc,t)*HeatrF(F,j)*FuelPrice(j,t))+
              sum((NG,ldc,t),ENG(NG,ldc,t)*Timeldc(ldc,t)*NGcost(t)*HeatrNG(NG))+

* Retrofit cost due to fuel switching on existing power plants
              sum((F,tc),RcostF(F)*GrossCapF(F)*retro(F,tc))+

* Capital cost for NEW fossil fuel power plant with and without capture
              sum((NFP,tc,t),CcostNFP(NFP,tc,t)*GrossCapNFP(NFP)*yNFP(NFP,tc))+
              sum((NFPC,tc,t),CcostNFPC(NFPC,tc,t)*GrossCapNFPC(NFPC)*yNFPC(NFPC,tc))+

* Capital cost for NEW nuclear and Imports
              sum((NNuc,tc,t),CcostNNuc(NNuc,tc,t)*GrossCapNNuc(NNuc)*yNNuc(NNuc,tc))+
              sum((Impo,tc,t),CcostImpo(Impo,tc,t)*GrossCapImpo(Impo)*yImpo(Impo,tc))+

* Fixed operating cost for new fossil fuel power plant with and without capture
              sum((NFP,tc,t),FixOprNFP(NFP)*NetCapNFP(NFP,tc,t)*yNFP(NFP,tc))+
              sum((NFPC,tc,t),FixOprNFPC(NFPC)*NetCapNFPC(NFPC,tc,t)*yNFPC(NFPC,tc))+

* Variable operating cost for new fossil fuel power plant with and without capture
              sum((NFP,t,ldc),VarOprNFP(NFP)*ENFP(NFP,ldc,t)*Timeldc(ldc,t))+
              sum((NFPC,t,ldc),VarOprNFPC(NFPC)*ENFPC(NFPC,ldc,t)*Timeldc(ldc,t))+

* Fuel Cost for new fossil fuel power plant with and without capture

              sum((PP1,ldc,t),Pcoal(t)*HeatrNFP(PP1)*ENFP(PP1,ldc,t)*Timeldc(ldc,t))+
              sum((PP2,ldc,t),Pcoal(t)*HeatrNFP(PP2)*ENFP(PP2,ldc,t)*Timeldc(ldc,t))+
              sum((PP3,ldc,t),Pcoal(t)*HeatrNFP(PP3)*ENFP(PP3,ldc,t)*Timeldc(ldc,t))+
              sum((PI1,ldc,t),Pcoal(t)*HeatrNFP(PI1)*ENFP(PI1,ldc,t)*Timeldc(ldc,t))+
              sum((PI2,ldc,t),Pcoal(t)*HeatrNFP(PI2)*ENFP(PI2,ldc,t)*Timeldc(ldc,t))+
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            sum((PI3,ldc,t),Pcoal(t)*HeatrNFP(PI3)*ENFP(PI3,ldc,t)*Timeldc(ldc,t))+
            sum((PN1,ldc,t),NGcost(t)*HeatrNFP(PN1)*ENFP(PN1,ldc,t)*Timeldc(ldc,t))+
            sum((PN2,ldc,t),NGcost(t)*HeatrNFP(PN2)*ENFP(PN2,ldc,t)*Timeldc(ldc,t))+
            sum((PN3,ldc,t),NGcost(t)*HeatrNFP(PN3)*ENFP(PN3,ldc,t)*Timeldc(ldc,t))+
            sum((PC1,ldc,t),Pcoal(t)*HeatrNFPC(PC1)*ENFPC(PC1,ldc,t)*Timeldc(ldc,t))+
            sum((PC2,ldc,t),Pcoal(t)*HeatrNFPC(PC2)*ENFPC(PC2,ldc,t)*Timeldc(ldc,t))+
            sum((PC3,ldc,t),Pcoal(t)*HeatrNFPC(PC3)*ENFPC(PC3,ldc,t)*Timeldc(ldc,t))+
            sum((IIC1,ldc,t),Pcoal(t)*HeatrNFPC(IIC1)*ENFPC(IIC1,ldc,t)*Timeldc(ldc,t))+
            sum((IIC2,ldc,t),Pcoal(t)*HeatrNFPC(IIC2)*ENFPC(IIC2,ldc,t)*Timeldc(ldc,t))+
            sum((IIC3,ldc,t),Pcoal(t)*HeatrNFPC(IIC3)*ENFPC(IIC3,ldc,t)*Timeldc(ldc,t))+
            sum((NC1,ldc,t),NGcost(t)*HeatrNFPC(NC1)*ENFPC(NC1,ldc,t)*Timeldc(ldc,t))+
            sum((NC2,ldc,t),NGcost(t)*HeatrNFPC(NC2)*ENFPC(NC2,ldc,t)*Timeldc(ldc,t))+
            sum((NC3,ldc,t),NGcost(t)*HeatrNFPC(NC3)*ENFPC(NC3,ldc,t)*Timeldc(ldc,t))+

*Fixed O&M cost include fuel for NEW nuclear and Imports
            sum((NNuc,tc,t),FixOprNNuc(NNuc)*NetCapNNuc(NNuc,tc,t)*yNNuc(NNuc,tc))+
            sum((Impo,tc,t),FixOprImpo(Impo)*NetCapImpo(Impo,tc,t)*yImpo(Impo,tc))+

*Variable O&M cost include fuel for NEW nuclear and Imports
            sum((NNuc,ldc,t),VarOprNNuc(NNuc)*ENNuc(NNuc,ldc,t)*Timeldc(ldc,t))+
            sum((Impo,ldc,t),VarOprImpo(Impo)*EImpo(Impo,ldc,t)*Timeldc(ldc,t))+

*Capital and operating cost for capture process on existing fossil stations
            sum((F,j,k,ldc,t),ccsF(F)*perCCS*CO2F(F,j)*gamaF(F,j,k,ldc,t)*Timeldc(ldc,t))+
            sum((NFPC,ldc,t),ccsNFPC(NFPC)*CO2NFPC(NFPC)*ENFPC(NFPC,ldc,t)*Timeldc(ldc,t))+
*Cost of purchasing CO2 emission credits
            sum(t,Credit(t)*CreditCost(t)));

*===========================EXPENDITURE REPORT==============================
*==========================================================================

Equation CapitalNew(t),CapitalRetro(tc),CapitalFixOld(t),CapitalFixNew(t), CapitalFuel(t),
      CapitalVarOld(t),CapitalVarNew(t),CapitalCCS(t),CapitalCredit(t) ;
variable CapitalExpenNew(t),CapitalExpenRetro(tc),CapitalExpenFixOld(t),CapitalExpenFixNew(t),
      CapitalExpenFuel(t),CapitalExpenVarOld(t),CapitalExpenVarNew(t),CapitalExpenCCS(t),
      CapitalExpenCredi(t);
CapitalNew(t)..  CapitalExpenNew(t) =e= sum((NFP,tc),CcostNFP(NFP,tc,t)*GrossCapNFP(NFP)*yNFP(NFP,tc))+
            sum((NFPC,tc),CcostNFPC(NFPC,tc,t)*GrossCapNFPC(NFPC)*yNFPC(NFPC,tc))+
            sum((NNuc,tc),CcostNNuc(NNuc,tc,t)*GrossCapNNuc(NNuc)*yNNuc(NNuc,tc))+
            sum((Impo,tc),CcostImpo(Impo,tc,t)*GrossCapImpo(Impo)*yImpo(Impo,tc));

CapitalRetro(tc).. CapitalExpenRetro(tc) =e= sum((F),RcostF(F)*GrossCapF(F)*retro(F,tc));

CapitalFixOld(t)..    CapitalExpenFixOld(t)=e=
            sum((F,j),XF(F,j,t)*FixOprF(F,j)*GrossCapF(F))+
            sum((NG),yNG(NG,t)*FixOprNG(NG)*GrossCapNG(NG))+
            sum((ENuc),yENuc(ENuc,t)*FixOprENuc(ENuc)*GrossCapENuc(Enuc,t))+
            sum((H),yH(H,t)*FixOprH(H)*GrossCapH(H))+
            sum((W),yw(W,t)*FixOprW(W)*GrossCapW(W));

CapitalFixNew(t)..   CapitalExpenFixNew(t)=e=
             sum((NFP,tc),FixOprNFP(NFP)*NetCapNFP(NFP,tc,t)*yNFP(NFP,tc))+
             sum((NFPC,tc),FixOprNFPC(NFPC)*NetCapNFPC(NFPC,tc,t)*yNFPC(NFPC,tc))+
             sum((NNuc,tc),FixOprNNuc(NNuc)*NetCapNNuc(NNuc,tc,t)*yNNuc(NNuc,tc))+
             sum((Impo,tc),FixOprImpo(Impo)*NetCapImpo(Impo,tc,t)*yImpo(Impo,tc));

CapitalFuel(t)..    CapitalExpenFuel(t)=e=
            sum((F,j,ldc), EFj(F,j,ldc,t)*Timeldc(ldc,t)*HeatrF(F,j)*FuelPrice(j,t))+
            sum((NG,ldc),ENG(NG,ldc,t)*Timeldc(ldc,t)*NGcost(t)*HeatrNG(NG))+
            sum((PP1,ldc),Pcoal(t)*HeatrNFP(PP1)*ENFP(PP1,ldc,t)*Timeldc(ldc,t))+
            sum((PP2,ldc),Pcoal(t)*HeatrNFP(PP2)*ENFP(PP2,ldc,t)*Timeldc(ldc,t))+
            sum((PP3,ldc),Pcoal(t)*HeatrNFP(PP3)*ENFP(PP3,ldc,t)*Timeldc(ldc,t))+
            sum((PI1,ldc),Pcoal(t)*HeatrNFP(PI1)*ENFP(PI1,ldc,t)*Timeldc(ldc,t))+
            sum((PI2,ldc),Pcoal(t)*HeatrNFP(PI2)*ENFP(PI2,ldc,t)*Timeldc(ldc,t))+
            sum((PI3,ldc),Pcoal(t)*HeatrNFP(PI3)*ENFP(PI3,ldc,t)*Timeldc(ldc,t))+
            sum((PN1,ldc),NGcost(t)*HeatrNFP(PN1)*ENFP(PN1,ldc,t)*Timeldc(ldc,t))+
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          sum((PN2,ldc),NGcost(t)*HeatrNFP(PN2)*ENFP(PN2,ldc,t)*Timeldc(ldc,t))+
          sum((PN3,ldc),NGcost(t)*HeatrNFP(PN3)*ENFP(PN3,ldc,t)*Timeldc(ldc,t))+
          sum((PC1,ldc),Pcoal(t)*HeatrNFPC(PC1)*ENFPC(PC1,ldc,t)*Timeldc(ldc,t))+
          sum((PC2,ldc),Pcoal(t)*HeatrNFPC(PC2)*ENFPC(PC2,ldc,t)*Timeldc(ldc,t))+
          sum((PC3,ldc),Pcoal(t)*HeatrNFPC(PC3)*ENFPC(PC3,ldc,t)*Timeldc(ldc,t))+
          sum((IIC1,ldc),Pcoal(t)*HeatrNFPC(IIC1)*ENFPC(IIC1,ldc,t)*Timeldc(ldc,t))+
          sum((IIC2,ldc),Pcoal(t)*HeatrNFPC(IIC2)*ENFPC(IIC2,ldc,t)*Timeldc(ldc,t))+
          sum((IIC3,ldc),Pcoal(t)*HeatrNFPC(IIC3)*ENFPC(IIC3,ldc,t)*Timeldc(ldc,t))+
          sum((NC1,ldc),NGcost(t)*HeatrNFPC(NC1)*ENFPC(NC1,ldc,t)*Timeldc(ldc,t))+
          sum((NC2,ldc),NGcost(t)*HeatrNFPC(NC2)*ENFPC(NC2,ldc,t)*Timeldc(ldc,t))+
          sum((NC3,ldc),NGcost(t)*HeatrNFPC(NC3)*ENFPC(NC3,ldc,t)*Timeldc(ldc,t));

CapitalVarOld(t)..
          CapitalExpenVarOld(t)=e=
          sum((F,j,ldc),EFj(F,j,ldc,t)*Timeldc(ldc,t)*VarOprF(F,j))+
          sum((NG,ldc),ENG(NG,ldc,t)*Timeldc(ldc,t)*VarOprNG(NG))+
          sum((ENuc,ldc),EENuc(ENuc,ldc,t)*Timeldc(ldc,t)*VarOprENuc(ENuc))+
          sum((H,ldc),EH(H,ldc,t)*Timeldc(ldc,t)*VarOprH(H))+
          sum((W,ldc),EW(W,ldc,t)*Timeldc(ldc,t)*VarOprW(W));

CapitalVarNew(t)..  CapitalExpenVarNew(t)=e=
          sum((NFP,ldc),VarOprNFP(NFP)*ENFP(NFP,ldc,t)*Timeldc(ldc,t))+
          sum((NFPC,ldc),VarOprNFPC(NFPC)*ENFPC(NFPC,ldc,t)*Timeldc(ldc,t))+
          sum((NNuc,ldc),VarOprNNuc(NNuc)*ENNuc(NNuc,ldc,t)*Timeldc(ldc,t))+
          sum((Impo,ldc),VarOprImpo(Impo)*EImpo(Impo,ldc,t)*Timeldc(ldc,t));

CapitalCCS(t)..     CapitalExpenCCS(t)=e=
          sum((F,j,k,ldc),ccsF(F)*perCCS*CO2F(F,j)*gamaF(F,j,k,ldc,t)*Timeldc(ldc,t))+
          sum((NFPC,ldc),ccsNFPC(NFPC)*CO2NFPC(NFPC)*ENFPC(NFPC,ldc,t)*Timeldc(ldc,t));

CapitalCredit(t)..  CapitalExpenCredi(t)=e= (Credit(t)*CreditCost(t));

*===========================MODEL CONSTRAINT==============================
*==========================================================================

*======================CO2 SYSTEM INFORMATION++++========================
*==========================================================================

Equation
totCO2(t)  total (from all power stations) CO2 emission during period t (tonne per year)
totCO2F1(t),totCO2F2(t),totCO2F3(t),totCO2F5(t),totCO2F6(t),totCO2F7,totCO2P(t);

* Lambton CO2 emissions during period t
totCO2F1(t)..  CO2F1(t) =e= sum((L,j,ldc),CO2F(L,j)*EFj(L,j,ldc,t)*Timeldc(ldc,t))-
               (sum((L,j,k,ldc),CO2F(L,j)*perCCS*gamaF(L,j,k,ldc,t)*Timeldc(ldc,t)));
* Nanticoke CO2 emissions during period t
totCO2F2(t).. CO2F2(t) =e= sum((NN,j,ldc),CO2F(NN,j)*EFj(NN,j,ldc,t)*Timeldc(ldc,t))-
              (sum((NN,j,k,ldc),CO2F(NN,j)*perCCS*gamaF(NN,j,k,ldc,t)*Timeldc(ldc,t)));
* Atitokan CO2 emissions during period t
totCO2F3(t)..  CO2F3(t) =e= sum((A,j,ldc),CO2F(A,j)*EFj(A,j,ldc,t)*Timeldc(ldc,t))-
               (sum((A,j,k,ldc),CO2F(A,j)*perCCS*gamaF(A,j,k,ldc,t)*Timeldc(ldc,t)));
* Lennox Power Plant CO2 emissions during period t
totCO2F5(t).. CO2F5(t) =e= sum((LN,j,ldc),CO2F(LN,j)*EFj(LN,j,ldc,t)*Timeldc(ldc,t));
* Thunder Bay CO2 emissions during period t
totCO2F6(t).. CO2F6(t) =e= sum((TB,j,ldc),CO2F(TB,j)*EFj(TB,j,ldc,t)*Timeldc(ldc,t))-
              (sum((TB,j,k,ldc),CO2F(TB,j)*perCCS*gamaF(TB,j,k,ldc,t)*Timeldc(ldc,t)));
* Existing NG Power Plant CO2 emissions during period t
totCO2F7(t).. CO2F7(t) =e= sum((NG,ldc), CO2NG(NG)*ENG(NG,ldc,t)*Timeldc(ldc,t));
* CO2 Emissions From New Power Plants during period t
totCO2P(t).. CO2P(t) =e= sum((NFP,ldc),CO2NFP(NFP)*ENFP(NFP,ldc,t)*Timeldc(ldc,t))+
                 sum((NFPC,ldc),CO2NFPC(NFPC)*ENFPC(NFPC,ldc,t)*Timeldc(ldc,t));
* Total CO2 emissions during period t (tonne per yr)

totCO2(t)..     CO2F1(t)+CO2F2(t)+CO2F3(t)+CO2F5(t)+CO2F6(t)+CO2F7(t)+CO2P(t)-Credit(t)=l= CO2Limit(t);

*===========================ENERGY CONSTRAINT==============================
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*==========================================================================

* energy required for capture process on fossil stations during period t (MWh per yr)

totEkF(F,j,k,ldc,t)..   EkFj(F,j,k,ldc,t) =e= CO2F(F,j)*EreqF(F,j)*perCCS*gamaF(F,j,k,ldc,t)*Timeldc(ldc,t);

* total net electricity generated must satisfy forecated demand in period t

totMWh(ldc,t).. (1-loss)*(sum((F,j),EFj(F,j,ldc,t)*Timeldc(ldc,t))+
                sum(ENuc,EENuc(ENuc,ldc,t)*Timeldc(ldc,t))+
                sum(H,EH(H,ldc,t)*Timeldc(ldc,t))+
                sum(W,EW(W,ldc,t)*Timeldc(ldc,t))+
                sum(NG,ENG(NG,ldc,t)*Timeldc(ldc,t))+

                sum(NFP,ENFP(NFP,ldc,t)*Timeldc(ldc,t))+
                sum(NFPC,ENFPC(NFPC,ldc,t)*Timeldc(ldc,t))+
                sum(NNuc,ENNuc(NNuc,ldc,t)*Timeldc(ldc,t))+
                sum(Impo,EImpo(Impo,ldc,t)*Timeldc(ldc,t))-
                sum((F,j,k),EkFj(F,j,k,ldc,t))) =g= GenDemand(ldc,t);

Equation Generation;
Positive variable Gen(ldc,t);

Generation(ldc,t).. Gen(ldc,t) =e= (1-loss)*(sum((F,j),EFj(F,j,ldc,t)*Timeldc(ldc,t))+
                sum(ENuc,EENuc(ENuc,ldc,t)*Timeldc(ldc,t))+
                sum(H,EH(H,ldc,t)*Timeldc(ldc,t))+
                sum(W,EW(W,ldc,t)*Timeldc(ldc,t))+
                sum(NG,ENG(NG,ldc,t)*Timeldc(ldc,t))+

                sum(NFP,ENFP(NFP,ldc,t)*Timeldc(ldc,t))+
                sum(NFPC,ENFPC(NFPC,ldc,t)*Timeldc(ldc,t))+
                sum(NNuc,ENNuc(NNuc,ldc,t)*Timeldc(ldc,t))+
                sum(Impo,EImpo(Impo,ldc,t)*Timeldc(ldc,t))-
                sum((F,j,k),EkFj(F,j,k,ldc,t)));


Equation Generation2,Generation3,Generation4,Generation5,Generation6,Generation7,
Generation8,Generation9,Generation10,Generation11;
Positive variable Gen2(ldc,t),Gen3(ldc,t),Gen4(ldc,t),Gen5(ldc,t),Gen11(ldc,t)
             Gen6(ldc,t),Gen7(ldc,t),Gen8(ldc,t),Gen9(ldc,t),Gen10(ldc,t);

Generation2(ldc,t).. Gen2(ldc,t) =e=  sum((F,j),EFj(F,j,ldc,t)*Timeldc(ldc,t));
Generation3(ldc,t).. Gen3(ldc,t) =e=  sum(ENuc,EENuc(ENuc,ldc,t)*Timeldc(ldc,t));
Generation4(ldc,t).. Gen4(ldc,t) =e=  sum(H,EH(H,ldc,t)*Timeldc(ldc,t));
Generation5(ldc,t).. Gen5(ldc,t) =e=  sum(W,EW(W,ldc,t)*Timeldc(ldc,t));
Generation6(ldc,t).. Gen6(ldc,t) =e=  sum(NG,ENG(NG,ldc,t)*Timeldc(ldc,t));
Generation7(ldc,t).. Gen7(ldc,t) =e=  sum(NFP,ENFP(NFP,ldc,t)*Timeldc(ldc,t));
Generation8(ldc,t).. Gen8(ldc,t) =e=  sum(NFPC,ENFPC(NFPC,ldc,t)*Timeldc(ldc,t));
Generation9(ldc,t).. Gen9(ldc,t) =e=  sum(NNuc,ENNuc(NNuc,ldc,t)*Timeldc(ldc,t));
Generation10(ldc,t).. Gen10(ldc,t) =e= sum(Impo,EImpo(Impo,ldc,t)*Timeldc(ldc,t));
Generation11(ldc,t).. Gen11(ldc,t) =e= sum((F,j,k),EkFj(F,j,k,ldc,t));


**Nuclear plants may not be used to meet peak load
Equation LdcENucBase(ENuc,t), LdcNNucBase(NNuc,t);

LdcENucBase(ENuc,t).. EENuc(ENuc,'peak',t) =e= 0;
LdcNNucBase(NNuc,t).. ENNuc(NNuc,'peak',t) =e= 0;

* Fuel selection and plant shut down

swiL(F,t)..       sum(j,XF(F,j,t)) =l= 1;

gas1(t)..         XF('LN1','coal',t) =e= 0;
gas2(t)..         XF('LN2','coal',t) =e= 0;
gas3(t)..         XF('LN3','coal',t) =e= 0;
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gas4(t)..          XF('LN4','coal',t) =e= 0;

* Existing Station Shut-down and Generation Capacity Constraint

epF(F,j,t)..     sum(ldc,EFj(F,j,ldc,t)) =l= NetCapF(F,t)*XF(F,j,t);
epENuc(ENuc,t).. sum(ldc,EENuc(ENuc,ldc,t)) =l= NetCapENuc(ENuc,t)*yEnUC(ENuc,t);
epNG(NG,t)..     sum(ldc,ENG(NG,ldc,t)) =e= NetCapNg(NG)*yNG(NG,t);
epH(H,t)..       sum(ldc,EH(H,ldc,t)) =e= NetCapH(H)*yH(H,t);
epW(W,t)..       sum(ldc,EW(W,ldc,t)) =e= NetCapW(W)*yW(W,t);


*lower bound on exiting power plants AND capacity factor constraint
epF2(F,j,t)..     sum(ldc,EFj(F,j,ldc,t)) =g= 0.1*NetCapF(F,t)*XF(F,j,t);
epENuc2(ENuc,t).. sum(ldc,EENuc(ENuc,ldc,t)) =g= 0.1*NetCapENuc(ENuc,t)*yEnUC(ENuc,t);

Equation CapFacF(F,j,t),CapFacENuc(ENuc,t);

CapFacF(F,j,t)..    sum(ldc,EFj(F,j,ldc,t)*Timeldc(ldc,t)) =l= NetCapF(F,t)*Optime*ACFF(F)*XF(F,j,t);
CapFacENuc(ENuc,t)..  sum(ldc,EENuc(ENuc,ldc,t)*Timeldc(ldc,t)) =l= NetCapENuc(ENuc,t)*Optime*ACFENuc(ENuc)*yEnUC(ENuc,t);

* Construction time lead time and maximum generation constraint for New plants
Equation  newNFP(NFP,t),newNFPC(NFPC,t),newNNuc(NNuc,t),newImpo(Impo,t);

newNFP(NFP,t)..    sum(ldc,ENFP(NFP,ldc,t)) =l= sum (tc,NetCapNFP(NFP,tc,t)*yNFP(NFP,tc));
newNFPC(NFPC,t)..   sum(ldc,ENFPC(NFPC,ldc,t)) =l= sum (tc,NetCapNFPC(NFPC,tc,t)*yNFPC(NFPC,tc));
newNNuc(NNuc,t)..  sum(ldc,ENNuc(NNuc,ldc,t)) =l= sum (tc,NetCapNNuc(NNuc,tc,t)*yNNuc(NNuc,tc));
newImpo(Impo,t)..  sum(ldc,EImpo(Impo,ldc,t)) =l= sum (tc,NetCapImpo(Impo,tc,t)*yImpo(Impo,tc));

Equation  newNFP2(NFP,t),newNFPC2(NFPC,t),newNNuc2(NNuc,t);

newNFP2(NFP,t)..    sum(ldc,ENFP(NFP,ldc,t)) =g= sum (tc,0.1*NetCapNFP(NFP,tc,t)*yNFP(NFP,tc));
newNFPC2(NFPC,t)..   sum(ldc,ENFPC(NFPC,ldc,t)) =g= sum (tc,0.1*NetCapNFPC(NFPC,tc,t)*yNFPC(NFPC,tc));
newNNuc2(NNuc,t)..  sum(ldc,ENNuc(NNuc,ldc,t)) =g= sum (tc,0.1*NetCapNNuc(NNuc,tc,t)*yNNuc(NNuc,tc));

Equation CapFacNFP,CapFacNFPC,CapFacNNuc,CapFacImpo;

CapFacNFP(NFP,t)..    sum(ldc,ENFP(NFP,ldc,t)*Timeldc(ldc,t)) =l=  sum (tc,NetCapNFP(NFP,tc,t)*yNFP(NFP,tc)*Optime*ACFNFP(NFP));
CapFacNFPC(NFPC,t)..    sum(ldc,ENFPC(NFPC,ldc,t)*Timeldc(ldc,t)) =l=  sum
(tc,NetCapNFPC(NFPC,tc,t)*yNFPC(NFPC,tc)*Optime*ACFNFPC(NFPC));
CapFacNNuc(NNuc,t)..    sum(ldc,ENNuc(NNuc,ldc,t)*Timeldc(ldc,t)) =l=  sum
(tc,NetCapNNuc(NNuc,tc,t)*yNNuc(NNuc,tc)*Optime*ACFNNuc(NNuc));
CapFacImpo(Impo,t)..    sum(ldc,EImpo(Impo,ldc,t)*Timeldc(ldc,t)) =l=  sum
(tc,NetCapImpo(Impo,tc,t)*yImpo(Impo,tc)*Optime*ACFImpo(Impo));

* retrofit constraints

retro1(F,t)..  PowerActiveRetro(F,t) =e= sum(tc$Rconstraint(F,tc,t), retro(F,tc));

retro2(F,t)..  PowerActiveRetro(F,t) =e= XF(F,"NG",t);

retro3(F)..  sum (tc, retro(F,tc)) =l= 1;

* Start of construction for new plant can occur only once during the time horizon

startNFP(NFP)..       sum(tc,yNFP(NFP,tc)) =l= 1;
startNFPC(NFPC)..      sum(tc,yNFPC(NFPC,tc)) =l= 1;
startNNuc(NNuc)..      sum(tc,yNNuc(NNuc,tc)) =l= 1;
startImpo(Impo)..      sum(tc,yImpo(Impo,tc)) =l= 1;

* CO2 capture energy constraints

c1(F,j,k,ldc,t)..     EkFj(F,j,k,ldc,t) =l= (MaxCapRetro*zF(F,j,k,t));

* Selection of CO2 capture process

f1(F,t)..          sum((j,k),zF(F,j,k,t)) =l= 1;
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* If the fossil plants shut down no capture process will put online

w1(F,j,t)..      sum(k,zF(F,j,k,t)) =l= XF(F,j,t);

* No capture process on natural gas power plants

z1(F,k,t)..     zF(F,'ng',k,t) =e= 0;

** LINEARIZATION ****Capture Process on Coal-fired station ****
conF1(F,j,k,ldc,t).. gamaF(F,j,k,ldc,t) =l= EFj(F,j,ldc,t);
conF2(F,j,k,ldc,t).. gamaF(F,j,k,ldc,t) =g= EFj(F,j,ldc,t)-M*(1-zF(F,j,k,t));
conF3(F,j,k,ldc,t).. gamaF(F,j,k,ldc,t) =l= M*zF(F,j,k,t);

*Test
Equation hydro(t),hydro2(t);
hydro(t)..          sum(H,EH(H,'base',t)) =l= 3424;
hydro2(t)..          sum(H,EH(H,'base',t)) =e= 3424;

Model  kyoto /all /;

file opt /cplex.opt/;
*putclose opt 'probe 3';
*putclose opt 'probe 3'/'mipemphasis 2'/'cuts 2'/;
putclose opt 'probe 3'/'nodefileind 3'/'workmem 500'/;
*putclose opt 'probe 3'/'mipemphasis 2'/'mipordind =1'/;
kyoto.optfile=1;

option LIMROW = 0;
option LIMCOL = 0;
option optcr = 0;
option mip = CPLEX;
option iterlim = 1000000000;

option reslim = 16009000;

Solve kyoto using mip minimizing cost;

execute 'copy preformatted.xls results.xls';
execute_unload 'kyoto' EFj,EEnuc,EH,EW,ENG,XF,yENuc,yH,yW,yNG,ENFP,ENFPC,ENNuc,EImpo,
yNFP,yNFPC,yNNuc,yImpo,CO2F1,CO2F2,CO2F3,CO2F5,CO2F6,CO2P,CO2F7,CO2Limit,Credit,
zF,PowerActiveRetro,CapitalExpenNew,CapitalExpenRetro,CapitalExpenFixOld,
CapitalExpenFixNew,CapitalExpenFuel,CapitalExpenVarOld,CapitalExpenVarNew,
CapitalExpenCCS,CapitalExpenCredi,Timeldc,GenDemand,Gen,Gen2,Gen3,Gen4,Gen5,Gen6
Gen7,Gen8,Gen9,Gen10,Gen11;


execute 'GDXXRW i=kyoto.gdx o=results.xls var=EFj.l rng=Existing_Power!A1:AB109 merge'
execute 'GDXXRW i=kyoto.gdx o=results.xls var=EEnuc.l rng=Existing_Power!A117:AA127 merge'
execute 'GDXXRW i=kyoto.gdx o=results.xls var=EH.l rng=Existing_Power!A132:AA248 merge'
execute 'GDXXRW i=kyoto.gdx o=results.xls var=EW.l rng=Existing_Power!A252:AA258 merge'
execute 'GDXXRW i=kyoto.gdx o=results.xls var=ENG.l rng=Existing_Power!A265:AA305 merge'
*
execute 'GDXXRW i=kyoto.gdx o=results.xls var=XF.l rng=Shutdown_Existing!a1:AA55 merge'
execute 'GDXXRW i=kyoto.gdx o=results.xls var=yENuc.l rng=Shutdown_Existing!a62:z67 merge'
execute 'GDXXRW i=kyoto.gdx o=results.xls var=yH.l rng=Shutdown_Existing!a72:z130 merge'
execute 'GDXXRW i=kyoto.gdx o=results.xls var=yW.l rng=Shutdown_Existing!a134:z137 merge'
execute 'GDXXRW i=kyoto.gdx o=results.xls var=yNG.l rng=Shutdown_Existing!a144:Z164 merge'
*
execute 'GDXXRW i=kyoto.gdx o=results.xls var=ENFP.l rng=New_Power!a1:AA157 merge'
execute 'GDXXRW i=kyoto.gdx o=results.xls var=ENFPC.l rng=New_Power!a1:AA157 merge'
execute 'GDXXRW i=kyoto.gdx o=results.xls var=ENNuc.l rng=New_Power!a1:AA157 merge'
execute 'GDXXRW i=kyoto.gdx o=results.xls var=EImpo.l rng=New_Power!a1:AA157 merge'
*
execute 'GDXXRW i=kyoto.gdx o=results.xls var=yNFP.l rng=New_Construction!a1:Z79 merge'
execute 'GDXXRW i=kyoto.gdx o=results.xls var=yNFPC.l rng=New_Construction!a1:Z79 merge'
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execute 'GDXXRW i=kyoto.gdx o=results.xls var=yNNuc.l rng=New_Construction!a1:Z79 merge'
execute 'GDXXRW i=kyoto.gdx o=results.xls var=yImpo.l rng=New_Construction!a1:Z79 merge'

execute 'GDXXRW i=kyoto.gdx o=results.xls var=CO2F1.l rng=CO2_Emission!b3 merge'
execute 'GDXXRW i=kyoto.gdx o=results.xls var=CO2F2.l rng=CO2_Emission!b5 merge'
execute 'GDXXRW i=kyoto.gdx o=results.xls var=CO2F3.l rng=CO2_Emission!b7 merge'
execute 'GDXXRW i=kyoto.gdx o=results.xls var=CO2F5.l rng=CO2_Emission!b11 merge'
execute 'GDXXRW i=kyoto.gdx o=results.xls var=CO2F6.l rng=CO2_Emission!b13 merge'
execute 'GDXXRW i=kyoto.gdx o=results.xls var=CO2F7.l rng=CO2_Emission!b9 merge'
execute 'GDXXRW i=kyoto.gdx o=results.xls var=CO2P.l  rng=CO2_Emission!b15 merge'
execute 'GDXXRW i=kyoto.gdx o=results.xls par=CO2Limit rng=CO2_Emission!b21 merge'
execute 'GDXXRW i=kyoto.gdx o=results.xls var=Credit.l  rng=CO2_Emission!b19 merge'

execute 'GDXXRW i=kyoto.gdx o=results.xls var=wF.l rng=Sequestration_E!a1:AA55 merge'
execute 'GDXXRW i=kyoto.gdx o=results.xls var=wNFPC.l rng=Sequestration_N!a1:AA73 merge'

execute 'GDXXRW i=kyoto.gdx o=results.xls var=zF.l rng=CCS_Existing!a1:AB28 merge'

execute 'GDXXRW i=kyoto.gdx o=results.xls var=CapitalExpenNew.l rng=Expenditure!a3:p4 merge'
execute 'GDXXRW i=kyoto.gdx o=results.xls var=CapitalExpenRetro.l rng=Expenditure!a5:p6 merge'
execute 'GDXXRW i=kyoto.gdx o=results.xls var=CapitalExpenFixOld.l rng=Expenditure!a7:p8 merge'
execute 'GDXXRW i=kyoto.gdx o=results.xls var=CapitalExpenFixNew.l rng=Expenditure!a9:p10 merge'
execute 'GDXXRW i=kyoto.gdx o=results.xls var=CapitalExpenFuel.l rng=Expenditure!a11:p12 merge'
execute 'GDXXRW i=kyoto.gdx o=results.xls var=CapitalExpenVarOld.l rng=Expenditure!a13:p14 merge'
execute 'GDXXRW i=kyoto.gdx o=results.xls var=CapitalExpenVarNew.l rng=Expenditure!a15:p16 merge'
execute 'GDXXRW i=kyoto.gdx o=results.xls var=CapitalExpenCCS.l rng=Expenditure!a17:p18 merge'
execute 'GDXXRW i=kyoto.gdx o=results.xls var=CapitalExpenCredi.l rng=Expenditure!a19:p20 merge'

execute 'GDXXRW i=kyoto.gdx o=results.xls par=Timeldc rng=Summary!ac84:aw86 merge'
execute 'GDXXRW i=kyoto.gdx o=results.xls par=GenDemand rng=COE!B3:Q5 merge'

execute 'GDXXRW i=kyoto.gdx o=results.xls var=Gen rng=Gen!A1:P3 merge'
execute 'GDXXRW i=kyoto.gdx o=results.xls var=Gen2 rng=Gen!A5:P7 merge'
execute 'GDXXRW i=kyoto.gdx o=results.xls var=Gen3 rng=Gen!A9:P11 merge'
execute 'GDXXRW i=kyoto.gdx o=results.xls var=Gen4 rng=Gen!A13:P15 merge'
execute 'GDXXRW i=kyoto.gdx o=results.xls var=Gen5 rng=Gen!A17:P19 merge'
execute 'GDXXRW i=kyoto.gdx o=results.xls var=Gen6 rng=Gen!A21:P23 merge'
execute 'GDXXRW i=kyoto.gdx o=results.xls var=Gen7 rng=Gen!A25:P27 merge'
execute 'GDXXRW i=kyoto.gdx o=results.xls var=Gen8 rng=Gen!A29:P31 merge'
execute 'GDXXRW i=kyoto.gdx o=results.xls var=Gen9 rng=Gen!A33:P35 merge'
execute 'GDXXRW i=kyoto.gdx o=results.xls var=Gen10 rng=Gen!A37:P39 merge'
execute 'GDXXRW i=kyoto.gdx o=results.xls var=Gen11 rng=Gen!A41:P43 merge'

execute 'ShellExecute results.xls';
```