Report of the Development of a Canadian Electricity Sector Module for the Integrated Planning Model®:

A documentation report.

Final Report - May, 2005

Acknowledgment

The development of a Canadian module to the Integrated Planning Model (IPM) has come about through the support and collaboration of experts in several federal government departments including Environment Canada, Natural Resources Canada, Industry Canada and Foreign Affairs Canada. Through this collaboration, inputs and assumptions to the Canadian module were assembled. The assumptions and inputs underlying Canada's Base Case and associated policy cases were incorporated into IPM by ICF Consulting Canada. IPM was developed by ICF Resources and IPM® is a registered trademark of ICF Resources.

This document was prepared by Environment Canada with advice and guidance from Canadian experts, the Environmental Protection Agency (EPA), ICF Resources, and ICF Consulting Canada.

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Chapter 1 Introduction

In June 2003, the Administrator of the U.S. Environmental Protection Agency (EPA) and the Canadian Environment Minister announced three joint projects to be implemented under a Border Air Quality Strategy. Identification of the joint projects fulfilled a pledge made by the two countries in January 2003 to build on the success of the *1991 U.S.-Canada Air Quality Agreement*, which established a framework for collaboration on science and emission reductions in both countries.

The joint projects were intended to explore opportunities for coordinated air quality management that could result in air quality improvements and the establishment of innovative strategies. One of the three projects announced was the **Feasibility Study for Cross-border Cap and Trade of NO_x and SO_2 Emissions.**

The feasibility study is a national-level project to allow joint analysis of the feasibility of cross-border trading of capped emissions of nitrogen oxides (NO_x) and sulphur dioxide (SO_2). The goals of the project are to (1) evaluate impacts of potential cross border trading on ambient air in both countries; (2) assess divergences/gaps in measuring, monitoring, tracking, and reporting in each country; (3) analyze compliance regimes and identify divergences in accountability frameworks; and (4) describe the legal and regulatory infrastructure pertaining to NO_x and SO_2 emissions in each country.

The feasibility study is being conducted under the *Canada-U.S. Air Quality Agreement* and will report its conclusions in June 2005 to the Committee which administers the *Agreement*, the Air Quality Committee.

An important tool within the Feasibility Study is the creation of an analytical tool through which to assess the impact of NO_x and SO_2 cap and trading within the electricity sector. The United States has, for the last decade, developed a capacity to analyze electricity sector trading under their existing U.S. SO_2 Acid Rain Program, the Ozone Transport Commission NOx cap and trade and the NO_x Budget Trading Program using the Integrated Planning Model (IPM). Because of the importance of using a tool for the feasibility study that already incorporates the U.S. electricity sector and the trading within it, a Canadian electricity sector module for the IPM has been developed to enable joint Canada-U.S. modelling using IPM.

The Canadian module is intended to provide a representation of the Canadian electric power sector comparable to the representation of the electric power sector in the implementation of the IPM being used by the U.S. EPA. The sector scope includes power sector generators that sell the majority of their output to the grid. The geographic scope includes all provinces. Although the IPM model is capable of modelling many pollutants in the electricity sector including CO2, Mercury, and Particulate Matter, the pollutants of focus in this module are SO2 and NOx.

With inclusion of the Canadian power sector, IPM provides outputs at the national and provincial level, and provides unit-level, point source emissions values that can be used as inputs to atmospheric transport modelling to assess ambient air quality and acid deposition effects.

Development of the Canadian module has come about through the support and collaboration of experts in several federal government departments including Environment Canada, Natural Resources Canada, Industry Canada and Foreign Affairs Canada. Through this collaboration, inputs to the Canadian module were assembled using the best information available at the time.

The project to develop the Canadian module for the Integrated Planning Model® was intended to:

(1) create a tool that may be used by Environment Canada (EC) in support of analyzing cross-border emissions trading issues. This tool should represent the Canadian power sector (excluding industrial boilers) and should be capable of being used in conjunction with the IPM implementation currently exercised by ICF Resources in support of U.S. EPA which covers the U.S. power sector and excludes industrial boilers.

(2) design, program, test, implement, and document a model of the Canadian power sector that will be compatible with the model that is being used by the U.S. EPA and

provide the capability to run the Canadian power sector model in combination with the implementation of IPM for EPA's Base Case to perform cross-border emissions policy analysis.

(3) program, test, debug, and make operational a Canadian power sector module that is fully integrated with the model that is being used by the U.S. EPA. The Canadian power sector module will be designed to seamlessly "dock" with the U.S. EPA model to allow coordinated analysis of possible future cross-border emission impacts, requiring consistent assumptions and inputs on key drivers (e.g., technologies, economic activity, fuel markets) so that results reflect the relative opportunities in the system being modeled and not artefacts of the modelling assumptions.

This **Report of the Development of a Canadian Electricity Sector Module for the Integrated Planning Model®** is organized to do the following:

1) summarize in Chapter 2 the IPM and the results it can provide;
2) outline in detail, in Chapters 3 to 7 inclusive, the inputs to the Canadian module; and
3) provide, in Chapter 8, the results for Canada of the IPM Base Case modelling.

Chapter 2: The IPM Modelling Framework

ICF Resources developed the Integrated Planning Model (IPM) to support analysis of the electric sector in the United States. EPA, state air regulatory agencies, utilities and other public and private sector clients have used IPM extensively for air regulatory analyses, market studies, strategy planning, due diligence, and economic impact assessments.

Chapter 2 summarizes the IPM model and how it can be used. Since detailed information about model structure and function can be found in the U.S. EPA IPM Documentation Report version 2.1 (http://www.epa.gov/airmarkets/epa-ipm/) on IPM modelling, Chapter 2 is brief, touching upon only the key features of the model, required inputs and outputs.

2.1 IPM Overview

IPM is a well-established model of the electric power sector designed to help government and industry analyze a wide range of issues related to this sector. The model represents economic activities in key components of energy markets – fuel markets, emission markets, and electricity markets. Since the model captures the linkages in electricity markets, it is well suited for developing integrated analyses of the impacts of alternative regulatory policies on the power sector. In the past, applications of IPM have included capacity planning, environmental policy analysis and compliance planning, wholesale price forecasting, and asset valuation.

2.1.1 Purpose and Capabilities

IPM is a dynamic linear programming model that generates optimal decisions using perfect foresight. It determines the least-cost method of meeting energy demands and peak energy requirements over a specified period (e.g. 2007 to 2030). In its solution, the model considers a number of key operating or regulatory constraints (e.g. emission limits, transmission capabilities, renewable generation requirements, fuel market constraints) that are placed on the power and fuel markets. In particular, the model is well-suited to consider complex treatment of emission regulations involving trading, banking, and progressive flow control of emission allowances, as well as traditional command-and-control emission policies.

IPM models power markets through model regions that are geographical entities with distinct characteristics. For example, model regions representing the Canadian power market in the Canadian IPM Base Case 2004 correspond to the 10 Canadian provinces, treating Newfoundland and Labrador as separate model regions due to the lack of transmission capability between the two. IPM models the electric demand, generation, transmission, and distribution within each region as well as the inter-regional transmission grid. All existing utility power generation units, including renewable resources, are modeled, as well as independent power producers and cogeneration facilities that sell electricity to the grid.

IPM provides a detailed representation of new and existing resource options, including fossil generating options (coal steam, combustion turbines, combined cycles, and oil/gas steam), nuclear generating options, and renewable resources. Renewable resource options include wind, hydro, landfill gas, and biomass. A complete list of the plant types in the Canadian IPM Base Case 2004 is shown in Table 2.1.

Table 2.1. Plant Types in the Canadian IPM Base Case 2004

Fossil Fuel-Fired	**Renewables and Non-Conventional Technologies**
Coal Steam Oil/Gas Steam Combined Cycle Integrated Gasification Combined Cycle Turbine (Combustion and Advanced Combustion) Cogeneration Units Repowered Units	Hydro Biomass Wind Landfill Gas Fossil Waste Non-Fossil Waste
Non-Fossil Fuel-Fired	
Nuclear	

IPM can incorporate a detailed representation of fuel markets and can endogenously forecast fuel prices for coal, natural gas, and biomass by balancing fuel demand and supply for electric generation. The model also includes detailed fuel quality parameters to estimate emissions from electric generation.

IPM provides estimates of air emissions changes, regional wholesale energy and capacity prices, incremental electric power system costs, changes in fuel use, and capacity and dispatch projections.

2.2 Model Structure and Formulation

IPM employs a linear programming structure that is particularly well-suited for a dynamic electricity planning model designed to help decision makers plan system capacity and model the dispatch of electricity from individual units of plants. The model consists of three structural components: (1) a linear "objective function,: (2) a series of "decision variables," and (3) a set of linear "constraints" over which the objective function is minimized to yield an optimal solution.

- **Objective Function**: IPM's objective function is the summation of all the costs incurred by the electricity sector over the entire planning horizon. The total resulting cost is expressed as the net present value of all the component costs. These costs, which the linear programming formulation attempts to minimize, include the cost of new plant and pollution control construction, fixed and variable operating and maintenance costs, and fuel costs. Many of these cost components are captured in the objective function by multiplying the decision variables, described below, by a cost coefficient. Cost escalation factors are used in the objective function to reflect changes in cost over time. The applicable discount rates are applied to derive the net present value for the entire planning horizon from the costs obtained for all years in the planning horizon.

Decision Variables

- **Generation Dispatch Decision Variables**: IPM includes decision variables representing the generation from each plant or model plant[1]. For each model plant, a separate generation decision variable is defined for each possible combination of fuel, season, model run year, and segment of the seasonal load duration curve applicable to the model plant. In the objective function, each plant's generation decision variable is multiplied by the relevant heat rate and fuel price to obtain a fuel cost. It is also multiplied by the applicable variable operation and maintenance (VOM) cost rate to obtain the VOM cost for the plant.

- **Capacity Decision Variables**: IPM includes decision variables representing the capacity of each existing model plant and capacity additions associated with potential (new) units in each model run year. In the objective function, the decision variables representing existing capacity additions are multiplied by the relevant fixed operation and maintenance (FOM) cost rates to obtain the total FOM cost for a plant. The capacity addition decision variables are also multiplied by the investment cost and capital charge rates to obtain the capital cost associated with the capacity addition.

- **Transmission Decision Variables**: IPM includes decision variables representing the electricity transmission along each transmission link between model regions in each run year. In the objective function, these variables are multiplied by variable transmission cost rates to obtain the total cost of transmission across each link.

- **Emission Allowance Decision Variables**: For each relevant pollutant where allowance trading applies, IPM includes decision variables representing the total number of emission allowances for a given model run year that are bought and sold in that or subsequent run years.

- **Fuel Decision Variables**: For each type of fuel and each model run year, IPM defines decision variables representing the quantity of fuel delivered from each fuel supply region to model plants in each demand region. Coal decision variables are further differentiated according to coal rank (bituminous, sub-bituminous, and lignite) and sulphur grade (see Section 7.1 and Table 7.5),. These fuel quality decision variables do not appear in the IPM objective function, but in constraints which define the types of fuel that each model plant is eligible to use and the supply regions that are eligible to provide fuel to each specific model plant.

Constraints

- **Reserve Margin Constraints**: These constraints capture system reliability requirements by defining a minimum margin of reserve capacity (in megawatts) per year for each region. If existing plus planned capacity is not enough to satisfy the reserve margin requirement, the model will add the required level of new resources.

- **Demand Constraints**: The model divides regional annual demand into seasonal load segments represented in a load duration curve (LDC). Each segment in the LDC defines the minimum amount of generation required to meet the region's electrical demand during the specified season. These requirements are incorporated in the model's demand constraints.

- **Capacity Constraints**: These constraints specify how much electricity each plant can generate (a maximum generation level), given its capacity and seasonal availability.

[1] Model plants are aggregate representations of real life electricity generating units. For a discussion of model plants in the Canadian IPM Base Case 2004, see section 4.2.6.

- **Turn Down/Area Protection Constraints**: The model uses these constraints to take into account the cycling capabilities of the units, i.e., whether or not they can be shut down at night or on weekends, or whether they must operate at all times, at least at some minimum capacity level. These constraints ensure that the model reflects the distinct operating characteristics of peaking, cycling, and base load units.

- **Emission Constraints**: IPM can consider an array of emissions constraints for SO_2 and NO_x. Emission constraints can be implemented on a plant-by-plant, regional, or system-wide basis. The constraints can be defined in terms of total tonnage cap (e.g., tonnes of SO_2) or a maximum emission rate (e.g., lbs/mmBtu of NO_x). The scope, timing, and definition of the emission constraints depend on the required analysis.

- **Transmission Constraints**: IPM can simultaneously model any number of regions linked by transmission lines. The constraints define either a maximum capacity on each link, or a maximum level of transmission on two or more links (joint limits) to different regions.

- **Fuel Supply Constraints**: These constraints define the types of fuel that each model plant is eligible to use and the supply regions that are eligible to provide fuel to each specific model plant. A separate constraint is defined for each model plant.

2.3 Key Methodological Features of IPM

Short- and long-term projections of production activity can be obtained using a modelling tool like IPM. The model describes scenarios that might happen given the assumptions and methodologies. Cost and performance assumptions specific to the Canadian IPM Base Case 2004 are discussed in Chapters 3 – 7.

2.3.1 Model Plants

Theoretically, there is no predefined limit on the number of units that can be included in IPM. However, to keep model size and solution time within acceptable limits, IPM utilizes model plants to represent aggregations of actual individual generating units. The aggregation algorithm groups units with similar characteristics into model plants with a combined capacity and weighted-average characteristics that are representative of all the units comprising the model plant. Model plants are defined to maximize the accuracy of the model's cost and emissions estimates by capturing variations in key features of those units that are critical in the base case and anticipated policy case runs.

IPM also utilizes model plants to represent existing units, the retrofit and repowering options that are available to existing units and retirement options that are available to both existing and potential (new) units. IPM also uses model plants to represent new generation capacity that may be built during a model run. When it is economically advantageous to "build" new plants, IPM takes into account cost differentials between technologies, expected technology cost improvements (by differentiating costs based on a plant's vintage, i.e., build year) and regional variations in capital costs that are expected to occur over time.

The options available to each existing and potential (new) model plant are pre-defined at set-up.

2.3.2 Model Run Years

Model run years are used to represent the time duration used for each run. IPM can perform multiple year analyses while still maintaining a manageable model size and output density by mapping each run year in the duration for each run, or planning horizon. Each planning horizon represents a model run year. The model reports only results for run years requested, but always considers costs for all run years. An extra run year is used to avoid any bias, or modelling artefact, generated from using the final run year in analyses. In reality, any changes to policies affecting energy sector will have effects for many years. The Canadian IPM Base Case 2004 covers the period from 2007 – 2030, but only results from run years

(2007, 2010, 2015, and 2020) are used in analysis. The run year mapping used in the Canadian IPM Base Case 2004 is shown in Table 2.1.

Table 2.1. Run Years and Analysis Year Mapping Used in the Canadian IPM Base Case 2004

Run Year	Years Represented
2007	2007
2010	2008 – 2013
2015	2014 – 2017
2020	2018 – 2022
2026	2023 – 2030

2.3.3 Cost Accounting

As noted earlier in the chapter, IPM is a dynamic linear programming model that finds the least cost investment and electricity dispatch strategy for meeting electric demand subject to resource availability and other operating and environmental constraints. The cost components that IPM takes into account in deriving an optimal solution include the costs of investing in new supply options, the cost of installing and operating pollution control technology, fuel costs and the operation and maintenance costs associated with unit operations.

Several cost accounting assumptions are built into IPM's objective function in an effort to ensure a technically sound treatment of the cost of all investment options offered in the model. These features include:

- All costs in IPM's single multi-year objective function are discounted to a base year. Since the model solves for all run years simultaneously, discounting to a common base year ensures that IPM properly captures complex inter-temporal cost relationships.

- Capital costs in IPM's objective function are represented as the net present value of levelized stream of annual capital outlays, not as a one-time investment cost. The payment period used in calculating the levelized annual outlays never extends beyond the model's planning horizon: it is either the book life of the investment or the years remaining in the planning horizon, whichever is shorter. This treatment of capital costs ensures both realism and consistency in accounting for the full cost of each of the investment options in the model.

- The cost components appearing in IPM's objective function represent the composite cost over all years in the planning horizon rather than just the cost in the individual model run years. This permits the model to capture more accurately the escalation of the cost components over time.

2.3.4 Modelling Wholesale Electric Markets

Another important methodological feature worth noting about IPM is that it is designed to depict production activity in deregulated wholesale electric markets, not in retail markets. The model captures transmission costs and losses between IPM model regions. It is not designed to capture retail distribution costs. However, the model implicitly includes distribution losses since net energy for load[2], rather than delivered sales[3], is used to represent electric demand in the model. Additionally, the production costs calculated by

[2] Net energy for load is the electrical energy requirements of an electrical system, defined as system net generation, plus energy received from others, less energy delivered to others through interchange. It includes distribution losses.

[3] Delivered sales is the electrical energy delivered under a sales agreement. It does not include distribution losses.

IPM are the wholesale production costs. In reporting costs, the model does not include embedded costs, such as carrying charges of existing units that may be part of the retail cost.

2.3.5 Load Duration Curve

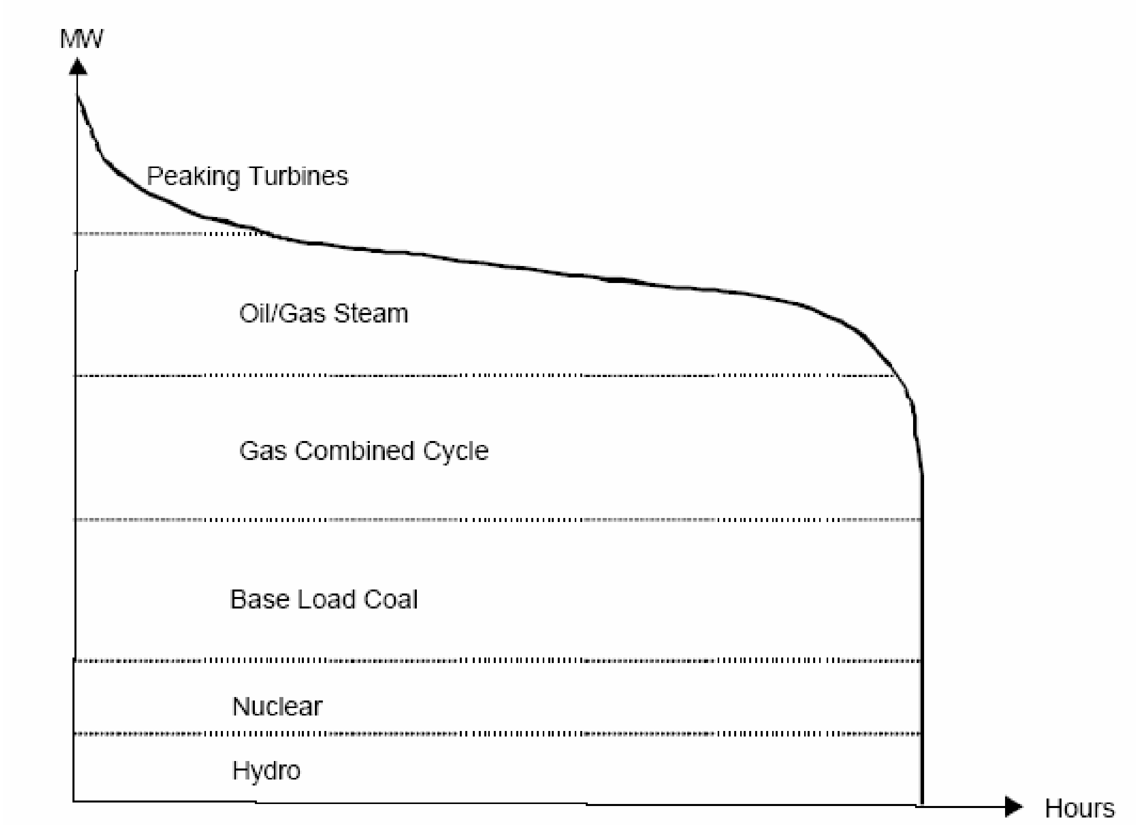
IPM uses of region-specific, seasonal load duration curves (LDCs) to capture the hourly profile of future electric demand. Unlike a chronological electric load curve, which is simply an hourly ordering of electric demand, an LDC is an ordering of electric demand from the highest hourly load to the lowest hourly load over the full duration of the period being depicted. IPM uses the annual chronological load curves to develop seasonal LDCs. IPM allows users to include any number of customized seasonal definitions. A season can be a single month or several months.

2.3.6 Dispatch Modelling

In IPM, the dispatching of electricity is based on the variable cost of generation. In the absence of any operating constraints, units with the lowest variable cost generate first. The marginal generating unit, i.e., the power plant that generates the last unit of electricity, sets the energy price. Physical operating constraints also influence the dispatch order. For example, IPM uses turndown constraints to prevent base load units from cycling, i.e., switching on and off. Turndown constraints often override the dispatch order that would result based purely on the variable cost of generation. Using variable costs in combination with turndown constraints enables IPM to dispatch generation resources in a technically realistic fashion.

In Figure 2.3 a hypothetical load duration curve is subdivided according to the type of generation resource that responds to the load requirements represented in the curve. Notice that the generation resources with the lowest operating cost (i.e., hydro and nuclear) respond first to the demand represented in the LDC and so are at the bottom of “dispatch stack”. They are dispatched for the maximum possible number of hours represented in the LDC. Generation resources with the highest operating cost (i.e., peaking turbines) are at the top of the “dispatch stack”, since they are dispatched last and for the minimum possible number of hours.

Figure 2.3. Stylized Dispatch Order



2.3.7 Reliability Modelling

Another methodological feature of IPM is its modelling of reliability through reserve margin requirements, which specify a percent over the peak demand that the electric system must maintain. IPM includes separate reserve margin requirements for each model region and run year.

2.3.8 Fuel Modelling

Another key methodological feature of IPM is its capability to flexibly model the full range of fuels used for electric power generation. The price, supply, and (if applicable) quality of each fuel included in the model are defined during model set-up. Fuel price and supply are specified though either a supply curve or an exogenous price point, both of which may vary over time. When a fuel supply curve is included, the model endogenously determines the price for that fuel by balancing the supply and demand. IPM uses the fuel quality information (e.g., the sulphur content of different types of coal from different supply regions) to determine the emissions resulting from the combustion of that fuel.

2.3.9 Transmission Modelling

IPM includes a detailed representation of existing transmission capabilities between model regions along with options for building new transmission lines. The maximum transmission capabilities between regions are specified in IPM's transmission constraints. Additions to transmission lines are represented by decision variables defined for each eligible link and model run year. In IPM's objective function, the decision variables representing transmission additions are multiplied by new transmission line investment cost and capital charge rates to obtain the capital cost associated with the transmission addition.

2.3.10 Perfect Competition and Perfect Foresight

Two key methodological features of IPM are its assumptions of perfect competition and perfect foresight. The former means that IPM models production activity in wholesale electric markets on the premise that these markets subscribe to all assumptions of perfect competition. The model does not explicitly capture any market imperfections such as market power, transaction costs, informational asymmetry or uncertainty. However, if desired, appropriately designed sensitivity analyses or redefined model parameters can be used to gauge the impact of market imperfections on the wholesale electric markets. Since the retail electric market is not modeled in IPM, there are no assumptions about the extent or timing of retail deregulation.

IPM's assumption of perfect foresight implies that economic agents know precisely the nature and timing of the constraints that will be imposed in future years. For example, under IPM there is complete foreknowledge of the levels, timing, and regulatory design of emission limits that will be imposed over the entire modelling time horizon. In making decision, agents optimize based on this foreknowledge. However, by performing an iterative series of runs, in which new emission limits are successively added in subsequent model run years, imperfect foresight can be incorporated in IPM's projections.

2.3.11 Air Regulatory Modelling

Treatment of air regulations is endogenous in IPM. That is, by providing a comprehensive representation of compliance options, IPM enables environmental decisions to be made within the model based on least cost considerations, rather than exogenously imposing environmental choices on model results. For example, unlike other models that enter allowance prices as an exogenous input during model set-up, IPM obtains allowance prices as an output of the endogenous optimization process of finding the least cost compliance options in response to air regulations. (In linear programming terminology, they are the "shadow prices" of the respective emission constraints – a standard output produced in solving a linear programming problem.) IPM can capture a wide variety of regulatory program designs including cap-and-trade, command-and-control and renewable portfolio standards. IPM's representation of cap-and-trade programs can include allowance banking, trading, borrowing, progressive flow controls or emission taxes. Air regulations can be tailored to specific geographical regions and can be restricted to specific seasons.

2.4 Data Parameters for Model Inputs

IPM requires input parameters that characterize the Canadian electric system, economic outlook, fuel supply and air regulatory framework. Chapters 3-7 contain detailed discussions of the values assigned to these parameters in the Canadian IPM Base Case 2004. This section simply lists the key input parameters required by IPM:

- **<u>Electric System</u>**
  - *Existing Utility Generating Resources*
    - Plant Capacities
    - Heat Rates
    - Maintenance Schedule
    - Forced Outage Rate
    - Minimum Generation Requirements (Turn Down Constraint)
    - Fuels Used
    - Fixed and Variable O&M Costs
    - Emissions Limits or Emission Rates for NO_x, SO_2
    - Existing Pollution Control Equipment and Retrofit Options
    - Output Profile for Non-Dispatchable Resources
  - *New Generating Resources*

        - Cost and Operating Characteristics
        - Performance Characteristics
        - Limitations on Availability

    - *Other System Requirements*
        - Inter-regional Transmission Capabilities
        - Reserve Margin Requirements for Reliability
        - Area Protection
        - System Specific Generation Requirements
        - Regional Specification
- **<u>Economic Outlook</u>**
    - *Electric Demand*
        - Provincial Electric Demand
        - Load Curves
    - *Financial Outlook*
        - Capital Charge Rate
        - Discount Rate
- **<u>Fuel Supply</u>**
    - *Fuel Supply Curves for Coal imported from the U.S.*
    - *Fuel Price Points for Canadian Coal, Natural Gas, Biomass, Fuel Oil, Nuclear Fuel, and ORIMULSION®*
    - *Fuel Quality*
    - *Transportation Costs for Coal and Natural Gas, where necessary*
- **<u>Air Regulatory Outlook</u>**
    - *Air Regulations for NO_x and SO_2*
    - *Other Air Regulations*

2.5 Model Outputs

IPM produces a variety of output reports. These range from extremely detailed reports, which describe the results for each model plant and run year, to summary reports, which present results for regional and national aggregates. Individual topic areas can be included or excluded at the user's discretion. Since the entire model solution is stored, IPM can generate additional detailed reports from the stored solution as needed. Standard IPM reports cover the following topics:

- Generation
- Capacity Mix (by plant type and presence of absence of emission controls)
- Capacity additions and retirements
- Capacity prices
- Wholesale electricity prices
- Power production costs (capital VOM, FOM and fuel costs)
- Fuel consumption
- Fuel supply and demand
- Fuel prices for coal, natural gas, and other fuels
- Emissions (NO_x and SO_2)
- Allowance prices (only in policy cases where emissions trading is modeled, i.e., not in the Canadian IPM Base Case 2004)

Chapter 3: Canadian Module Power System Operation Assumptions

This chapter describes the assumptions pertaining to the Canadian electric power system contained in the Canadian IPM Base Case 2004.

3.1 Model Regions

The Canadian IPM Base Case 2004 is comprised of 11 model regions that characterize the Canadian power markets. It models the electricity sector in all 10 provinces in Canada and treats Newfoundland and Labrador as separate model regions because there is no transmission capability between Newfoundland and the mainland. The territories are not included in this Canadian implementation.

Table 3.1 lists the 11 Canadian model regions in the Canadian IPM Base Case 2004.

Table 3.1. Canadian Model Regions in the Canadian IPM Base Case 2004

Model Region	Region Description
NF	Newfoundland
NL	Labrador
PE	Prince Edward Island
NS	Nova Scotia
NB	New Brunswick
QC	Quebec
ON	Ontario
MB	Manitoba
SK	Saskatchewan
AB	Alberta
BC	British Columbia

The Canadian IPM Base Case 2004 is structurally compatible with the existing U.S. EPA IPM Base Case version 2.1.6. This permits the integration of the 11 Canadian model regions in the Canadian Base Case with the existing 26 U.S. model regions in the U.S. EPA IPM Base Case version 2.1.6 for joint analysis and modelling[4]. Figure 3.1 depicts the 37 combined model regions in the Canadian IPM Base Case 2004 and the U.S. EPA IPM Base Case version 2.1.6. For the complete listing of U.S. model regions in the EPA IPM Base Case, please consult Appendix 3.1.

[4] The transmission structure of the U.S. EPA IPM Base Case version 2.1.6 was updated as part of this analysis.

Figure 3.1: Canadian IPM Base Case 2004 and the U.S. EPA IPM Base Case Model Regions

3.2 Electric Load Modelling

Collectively, net energy for load and net internal demand, two inputs into the IPM model, represent the regional grid demand for electricity. Net energy for load is the projected annual electricity demand of a region, prior to accounting for regional transmission and distribution losses. The net energy for load may be met by internal generation or through imports. Net internal demand is the maximum hourly demand within a given year after considering interruptible demand. The assumptions for net internal demand in the Canadian IPM Base Case 2004 are discussed below in Section 3.2.4. Table 3.2 shows the electric demand assumptions (expressed as net energy for load) used in the Canadian IPM Base Case 2004. For the purposes of documentation, the table below describes the national net energy for load. However, the Canadian IPM Base Case 2004 uses provincial breakdowns of net energy for load for modelling, with separate net energy for load supplied for each province. The provincial net energy for load reflects the domestic demand for electricity, expressed in GWh, for each province in the Analysis and Modelling Group forecast developed in March 2002. The Analysis and Modelling Group is a federal-provincial-territorial body established under the National Climate Change Process.

Table 3.2. Electric Load Assumptions in the Canadian IPM Base Case 2004

Year	Net Energy for Load (GWh)
2007	613,718
2010	636,539
2015	679,886
2020	716,252

Note: For specific runs built upon the Canadian IPM Base Case 2004, the total national net energy for load resulting from the run may differ slightly from the assumptions shown due to the exports, imports, and computational rounding.

3.2.1 Electric Load Growth

The electric load growth assumptions are taken from the forecast indicated in Section 3.2 above.

3.2.2 Energy Efficiency Adjustments

In the Canadian IPM Base Case 2004, energy efficiency measures were not endogenously modeled. No additional exogenous adjustments over and above what was embedded in the forecast indicated in Section 3.2 were made.

3.2.3 Demand Elasticity

The Canadian IPM Base Case 2004 does not incorporate the impact of price of power on power demand.

3.2.4 Net Internal Demand (Peak Demand)

Net internal demand (peak demand) is the maximum capacity that is needed to meet hourly demand within a given year after removing interruptible demand. Net internal demand is defined in every province and is based on the forecast indicated in Section 3.2. Table 3.3 below summarizes the net internal demand data for the model run years. The values are a summation of the values for each model region and are said to be “non-coincidental,” since they represent the sum of each region’s net internal (peak) demand which need not occur in the same hour across all regions.

Table 3.3. National Non-Coincidental Net Internal Demand

Year	Net Internal Demand (MW)
2007	84,711
2010	87,776
2015	93,551
2020	98,517

3.2.5 Regional Load Shape

Provincial load curves are a measure of chronological hourly electric demand for each region and each year. These load curves are based on load curve data received from individual utilities or utility boards in each province. Data was obtained for load shapes for all provinces. New Brunswick and PEI are the only provinces without data. Therefore, default load curves based on data from the nearby U.S. state of Maine were used as a proxy. 2000 was found to be the most recent normal weather year[5] and, therefore, year 2000 load curves were used to represent a normal weather year in all regions.

[5] The term “normal weather year” refers to a representative year whose weather is closest to the long-term average weather. The normal weather year was chosen by comparing the sum of that year’s heating and cooling degree-days to the average of the historical data for that region.

3.3 Transmission

The Canadian power system is an agglomeration of distinct power markets interconnected by a transmission grid. As discussed earlier, the Canadian IPM Base Case 2004 characterizes Canada into 11 power markets regions. These regions correspond to the 10 Canadian provinces, treating Newfoundland and Labrador separately due to the lack of transmission capability between the two. The Canadian IPM Base Case 2004 includes explicit assumptions regarding the transmission grid connecting 10 of the 11 modeled power markets as well as the shared transmission grid between 10 of the 11 model regions in Canada and the U.S. power markets. This section details the assumptions about the transfer capabilities, wheeling costs and inter-regional transmission used in the Canadian IPM Base Case 2004.

3.3.1 Inter-regional Transmission Capability

The capability of a transmission link in IPM defines the maximum one-directional flow of power on that link. Figures 3.2 and 3.3 below depict the inter-regional transmission capabilities in the summer and winter seasons assumed in the Canadian IPM Base Case 2004. See Table A.3.1 in Appendix 3.1 for a full description of the U.S. model regions used in these figures.

Figure 3.2. Summer Transmission Interconnect Capacities (MW)

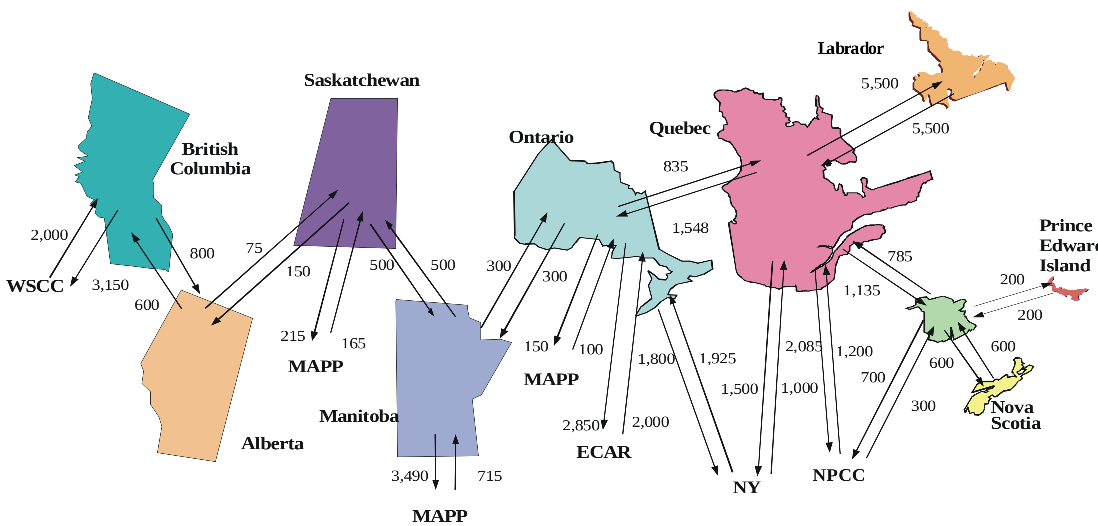
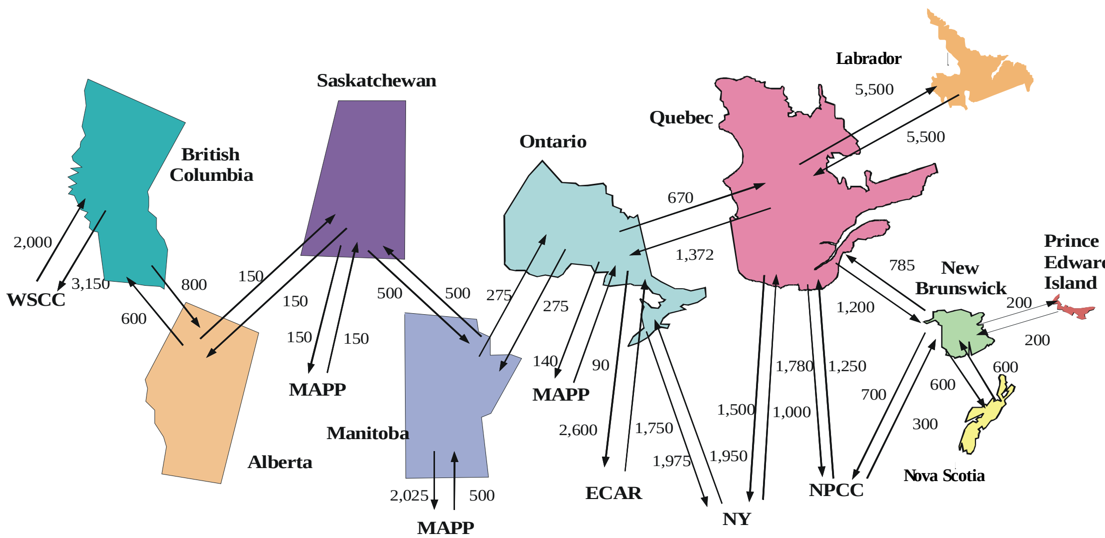


Figure 3.3. Winter Transmission Interconnect Capacities (MW)



Sources for Figures 3.2 and 3.3:
1- North American Electricity Reliability Council (NERC). 2003. "2003 Summer Assessment: Reliability of the Bulk Electricity Supply in North America." and "2002/03 Winter Assessment: Reliability of the Bulk Electricity Supply in North America." [Online] http://www.nerc.com
2- National Energy Board's *Canadian Electricity Exports and Imports: An Energy Market Assessment and the Canadian Electricity Trends and Issues: An Energy Market Assessment* documents.
3- Natural Resources Canada and Canadian Electricity Association: Electric Power in Canada 1998-1999.

3.3.2 Transmission Link Wheeling Charge

Transmission wheeling charge is the cost of transferring electric power from one model region to another using a transmission line. The Canadian IPM Base Case 2004 assumes a wheeling charge of 3 Cdn.mills/kWh[6]. In the joint modelling, the same[7] value is used for both the U.S. and Canada. This wheeling charge is applied to electricity transmission between IPM model regions.

3.3.3 Transmission Losses

The Canadian IPM Base Case 2004 assumes Canada-specific transmission losses, included in Table 3.4 below, which reflect average transmission losses between the provinces that initiate and that receive the power. Since IPM models the wholesale not the retail electric market, the Canadian IPM Base Case 2004 does not include assumptions about distribution losses, i.e., the loss of energy in the retail distribution of electricity.

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[6] A mill is one tenth of $0.01 (one cent).
[7] The wheeling charge in the US EPA IPM Base Case version 2.1.6 is 2 mills/kWh. This is equivalent to the Canadian value due to the exchange rate, which was set at $1.55CDN for every $1.00USD.

Table 3.4. Transmission Losses per Province in the Canadian IPM Base Case 2004

Province	NF	NL	PE	NS	NB	QC	ON	MB	SK	AB	BC
Transmission Losses	9%	9%	6%	4%	6%	4%	6%	12%	6%	4%	3%

Source: "Expert" estimates, based on transmission losses published in Energy Statistics Handbook, a joint publication of Statistics Canada and Natural Resources Canada.

3.3.4 Cost of Building New Transmission Lines

Two options are available with respect to transmission lines: the use of existing transmission lines and building new transmission lines. Transmission lines can be built in the model in the east-west direction. The cost of building such lines is based on the distance between the centres of the power systems, called the centroids, in each of the two neighbouring provinces and the per-unit cost of building the transmission line. Table 3.5 summarizes these distances. The distances were measured from "The Canadian Electric Power System" by Energy Map. Line costs consider costs of land and right of way, towers, poles, conductor, substations and other related equipment. In the Canadian IPM Base Case 2004, the option for new transmission lines between provinces was a 345 KV line having a 992 MW transmission capability. It was assumed to cost 1.13 CDN$/kW/km or 113 million CDN$ for a 100km line.

Table 3.5. Distance (Km) Between Regional Centroids

From Province	NF	PE	NB	QC	QC	ON	MB	SK	AB	BC
To Province	NL	NS	PE	NF	NB	QC	ON	MB	SK	AB
Distance (Km)	733	140	228	648	805	1155	1155	560	543	620

3.4 International Imports

The Canadian electric power system is connected with transmission grids in the U.S.. The two countries actively trade electricity. As indicated, the Canadian IPM Base Case 2004 is integrated with the U.S. EPA IPM Base Case version 2.1.6 (http://www.epa.gov/airmarkets/epa-ipm/) to reflect this reality and forecasts the net imports into Canada from the U.S.. The Canadian IPM Base Case 2004 derives values for international imports from model output. This is due to the fact that the Canadian IPM Base Case 2004 is a joint model with the U.S..

3.5 Capacity, Generation and Dispatch

While the capacity of existing units is exogenous to IPM, generation and dispatch are endogenous decisions in IPM. Existing capacity in the Canadian IPM Base Case 2004 is summarized in a database which provides IPM with data on all currently operating and planned-committed Canadian units. This data of existing and planned Canadian units is discussed in full in Section 4.1.

A unit's generation over a period of time is defined by its dispatch pattern over that duration of time. IPM determines the optimal economic dispatch profile given the operating and physical constraints imposed on the unit. In the Canadian IPM Base Case 2004, unit specific operating and physical constraints are generally captured through availability and turndown constraints. However, for some unit types, capacity factors are used to capture the resource or other physical constraints on generation. The two cases are discussed in more detail in the following two sections.

3.5.1 Availability

Power plant "availability" is the percentage of time that a generating unit is available to provide electricity to the grid. Availability takes into account both scheduled maintenance and forced outages; it is formally defined as the ratio of a unit's available hours adjusted for derating of capacity (due to partial outages) to the total number of hours in a year when the unit was in an active state. For most types of units in IPM, availability parameters are used to specify an upper bound on generation to meet demand. Table 3.6 summarizes the availability assumptions used in the Canadian IPM Base Case 2004. They are based on data from the North American Electric Reliability Council's Generating Availability Data System (NERC GADS) and AEO 2000. Unit types not contained in Table 3.6 are discussed in Section 3.5.2 below.

Table 3.6. Availability Assumptions in the Canadian IPM Base Case 2004

Unit Type	Availability (%)
Biomass	87.7
Coal Steam	85.0
Combined Cycle	90.4
Combustion Turbine	92.3
Gas/Oil Steam	85.0
IGCC	87.7
Pumped Storage	81.4

In the Canadian IPM Base Case 2004, separate seasonal (summer and winter) availabilities are defined. For the unit types shown in Table 3.7, summer and winter availabilities differ only in that no planned maintenance is assumed to be conducted during the on-peak summer (June, July and August) months. Characterizing the seasonal variations of hydro and wind technologies is more complicated due to the seasonal and locational variances of the resources on which they rely. The seasonal variations of hydro are presented in Section 3.5.2 and of wind in Section 4.4.3.

3.5.2 Capacity Factor

Generation from certain types of units is constrained by resource limitations. These technologies include hydro and wind. For such technologies, IPM uses capacity factors or generation profiles, not availabilities, to define the upper bound on the generation obtainable from the unit. The capacity factor is the percentage of the maximum possible power generated by the unit. For example, a hydro unit would have a capacity factor of 27% if the usable water were only available that percent of the time. For such units, explicit capacity factors or generation profiles mimic the resource availability. The seasonal capacity factor assumptions for hydro facilities were derived from Statistics Canada data. They are presented below in Table 3.7. A discussion of capacity factors and generation profiles for wind technology is contained in Section 4.4.3.

Table 3.7. Seasonal Hydro Capacity Factors (%) in the Canadian IPM Base Case 2004

IPM Region	Winter Capacity Factor (%)	Summer Capacity Factor (%)	Annual Capacity Factor (%)
NF	43.3	28.0	36.9
NL	85.0	56.0	72.8
NS	30.3	20.6	26.2
NB	33.6	31.7	32.8
QC	61.8	49.8	56.8
ON	54.5	49.4	52.4
MB	71.9	71.2	71.6
SK	44.3	47.4	45.6
AB	21.5	30.8	25.4
BC	60.8	52.4	57.3
National Weighed Average	61.8	51.1	57.3

Source: Statistics Canada

Capacity factors are also used to define the upper bound on generation obtainable from nuclear units. This rests on the assumption that nuclear units will either run at full capacity or not at all, and, consequently, capacity factors and availabilities are equivalent. The capacity factors (and, consequently, the availabilities) of existing nuclear units in the Canadian IPM Base Case 2004 vary from region to region and over time. Further discussion of the nuclear capacity factor assumptions in the Canadian IPM Base Case 2004 is contained in Section 4.5.

3.5.3 Turndown

Turndown assumptions in the Canadian IPM Base Case 2004 are used to prevent coal and oil/gas steam units from operating strictly as peaking units, which would be inconsistent with their operating capabilities. Specifically, the turndown constraints in the Canadian IPM Base Case 2004 require coal steam units to generate no less than 54 kWh of electricity in the lower four segments of the load duration curve for every 100 kWh of electricity generated in the top (peak) segment of the LDC. Oil/gas steam units are required to generate no less than 25 kWh of electricity in the lower four segments of the LDC for every 100 kWh of electricity generated in the top segment of the LDC. These turndown constraints were developed by ICF Resources through detailed assessments of the historical experience and operating characteristics of the existing fleet of coal steam and oil/gas steam units in the U.S. For example, in deriving the turndown factor for coal steam units, ICF Resources considered the number of coal pulverizers per unit as one indicator of the extent that units could respond to changing load.

3.6 Reserve Margins

A reserve margin is a measure of the system's generating capability above the amount required to meet the net internal demand (peak load) requirement. It is defined as the portion of total plant capacity that is considered to meet reliability requirements. It is expressed in percent. That is, dependable capacity minus annual system peak load divided by annual system peak load:

$$\text{Reserve Margin} = \frac{\text{Dependable Capacity} - \text{System Peak Load}}{\text{System Peak Load}} \times 100\%$$

In practice, each region has a reserve margin requirement, or comparable reliability standard, which is designed to encourage electric suppliers in the region to build beyond their peak requirements to ensure the reliability of the electric generation system within the region.

In IPM, reserve margins are used to depict the reliability standards that are in effect in each model region. Individual reserve margins for each model region are derived either directly or indirectly from electric reliability reports. They are based on reliability standards such as loss of load expectation (LOLE), which is defined as the expected number of days in a specified period in which the daily peak load will exceed the available capacity. The reserve margin assumptions used in the Canadian IPM Base Case 2004 are presented in Table 3.8 below.

Table 3.8. Provincial Reserve Margin Assumptions in the Canadian IPM Base Case 2004

Model Region	Reserve Margin (%)	Source
Newfoundland	20	Assumed to be the same as for Maritime Provinces
Labrador	20	Assumed to be the same as for Maritime Provinces
Prince Edward Island	20	NERC 2002-2011 Reliability Assessment
Nova Scotia	20	NERC 2002-2011 Reliability Assessment
New Brunswick	20	NERC 2002-2011 Reliability Assessment
Quebec	14	Assumed to be the same as for Ontario
Ontario	14	Ontario Independent Electricity Market Operator
Manitoba	15	NERC 2002-2011 Reliability Assessment
Saskatchewan	15	NERC 2002-2011 Reliability Assessment
Alberta	13.3	WECC 2003 Information Summary
British Columbia	13.3	WECC 2003 Information Summary

Each power plant can contribute all or a part of its capacity to satisfy the regional reserve margin requirements depending on its ability to be dispatched at the time of peak. It is assumed in the Canadian IPM Base Case 2004 that all power plants, other than hydro and wind plants, can contribute 100% of their capacity for reserve margin requirements. It is assumed that all hydro power plants can contribute 75% of their capacity for reserve margin requirements.

3.7 Power Plant Lifetimes

The Canadian IPM Base Case 2004 does not include any pre-specified assumptions about power plant lifetimes. To accommodate the absence of pre-specified plant lifetimes, all conventional fossil units (i.e., coal, oil/gas steam, combustion turbines, and combined cycle units) and nuclear units are provided with retirement options which allow units to retire due to economic factors. Other non-nuclear and non-fossil units are not provided an economic retirement option, either because they represent such a small portion of the generating population (renewables, landfills, and waste plants) or because an up-front assessment indicated that economics would not cause retirement (hydro and pumped storage).

Regarding life extension, the Canadian IPM Base Case 2004 assumes that every existing fossil or nuclear power plant has capital investments that extend its life beyond the modeled time horizon. The fixed O&M costs incorporate these life extension costs. All fossil and nuclear units in IPM, at age 40, are subject to a life extension cost of $5 US/KW-yr and $50 US/KW-yr of extra fixed O&M costs respectively. The treatment of power plant lifetimes and life extension costs in the Canadian IPM Base Case 2004 is consistent with the U.S. EPA IPM Base Case assumptions.

3.8 Heat Rates and Emission Rates

Heat rates, expressed as Btu/kWh or kJ/kWh, characterize the efficiency of a unit. Values for heat rates for coal steam plants were based on data from Environment Canada, while values for heat rates for non coal steam plants were defaults that were derived from the U.S. EPA NEEDS (National Electric Energy System) Database for IPM 2003 (IPM Base Case version 2.1.6).. Heat rates directly affect the fuel use of a plant, and therefore the emissions as well.

SO_2 and NO_x emission rates, expressed as g/MJ, characterize the mass of pollutants emitted per unit of heat input. Values for emission rates were based on data from Environment Canada along with defaults that were derived from the U.S. EPA NEEDS Database for IPM 2003 (IPM Base Case version 2.1.6).

3.9 Existing Environmental Regulations

The Canadian regulatory system for air quality is divided among the country's federal and provincial/territorial jurisdictions. Provincial governments have traditionally regulated stationary sources including power plants. Since 2000, the air management system in Canada has been enhanced through the introduction of Canada-wide Standards (CWSs) for particulate matter (PM) and ozone which may have a bearing on the regulations and permits given to power plants in the future.

Canada has a complex system of air regulations. The system contains national guidelines and objectives that provide a template for provincial and sector-specific regulations and permits. In addition, legally binding, international agreements and bilateral agreements between Federal and Provincial governments exist.

Table 3.9 summarizes all power sector related air emission regulations that are currently active and that are legally binding within the time horizon of this study.

Table 3.9. SO2 and NOx Emission Requirements Modelled in the Canadian IPM Base Case 2004

Province	Regulation/ Guideline	Authority	Scope and Power	Target
NF & NL	Federal-Provincial Agreements for Eastern Canada Acid Rain Program	Eastern Canadian Acid Rain Program	Fossil Power Plants, enacted 1994	**SO_2** – Cap 15 kilotonnes
PE	Federal-Provincial Agreements for Eastern Canada Acid Rain Program	Eastern Canadian Acid Rain Program	Fossil Power Plants, enacted 1994	**SO_2** – Cap 3 kilotonnes
NS	Federal-Provincial Agreements for Eastern Canada Acid Rain Program	Eastern Canadian Acid Rain Program	Fossil Power Plants, enacted 1994	**SO_2** – Cap 145 kilotonnes
NB	Federal-Provincial Agreements for Eastern Canada Acid Rain Program	Eastern Canadian Acid Rain Program	Fossil Power Plants, enacted 1994	**SO_2** – Cap 123 kilotonnes
QC	Ozone Annex	Annex 3 to the Canada-U.S. Air Quality Agreement	Fossil Fuel-Fired Generating Facilities in QC PEMA > 25 MW (2000)	**NO_x** – 5,000 tonnes in PEMA (2007+)
QC	Combustion Equipment Performance Standards	LQE	Combustion all Fossil Fuels, as of April, 2000	**SO_2** – Eq. of 2% of Weight of sulphur in Heavy Oil. (For the purpose of modelling, existing emission rates already account for these regulations and hence were not modeled explicitly.)
QC	Gas Turbines Guidelines	LQE	All Gas Turbines, as of April, 2000	**PM** – 0.2 g/MJ heat input **NO_x** – 1.3 g/MJ heat input (For the purpose of modelling, existing emission rates already account for these regulations and hence were not modeled explicitly.)
QC	Internal Combustion	LQE	IC > 1 MW, as of April, 2000	**NO_x** – 4.5 g/MJ heat input **CO** – 1.8 g/MJ heat input (For the purpose of modelling, existing emission rates already account for these regulations and hence were not modeled explicitly.)
QC	Combustion Equipment Performance Standards	LQE	Combustion Fossil (Coal) 3-70 MW, as of April, 2000	**PM** – New Facility 60 mg/MJ heat input **PM** – Old Facility 85 mg/MJ heat input (For the purpose of modelling, existing emission rates already account for these

				regulations and hence were not modeled explicitly.)
QC	Combustion Equipment Performance Standards	LQE	Combustion Fossil (Coal) > 70 MW, as of April, 2000	**PM** – New Facility 45 mg/MJ heat input **PM** – Old Facility 60 mg/MJ heat input (For the purpose of modelling, existing emission rates already account for these regulations and hence were not modeled explicitly.)
QC	Federal-Provincial Agreements for Eastern Canada Acid Rain Program	Eastern Canadian Acid Rain Program	Fossil Power Plants, enacted 1994	**SO_2** – Cap 6 kilotonnes
ON	Annual ON SO_2 Cap on electricity sector (Ontario Regulation 397/01)	Ontario's Emissions Trading System for Electricity Sector	Fossil Fuel-Fired Generating Facilities > 25 MW	**SO_2** – 2000 emissions – 590,000 tonnes electric power emissions in 2000 – 166,000 tonnes Cap 157.5 kilotonnes (2002) **SO_2** – Cap 131 kilotonnes (2007+)
ON	Annual ON NO_x Cap on electricity sector (Ontario Regulation 397/01)	Ontario's Emissions Trading System for Electricity Sector	Fossil Fuel-Fired Generating Facilities > 25 MW	**NO_x** – Cap 55.2 kilotonnes (2002-2006) **NO_x** – Cap 42.9 kilotonnes (2007+) in province
ON	Ozone Annex	Annex 3 to the Canada-U.S. Air Quality Agreement	Fossil Fuel-Fired Generating Facilities in Southern Ontario > 25 MW (2000)	**NO_x** – Cap 39,000 tonnes (2007+) in PEMA
ON	Regulation – General Air Pollution Guideline A-5 Stationary Turbines[8]	Ontario Environmental Protection Act	Stationary Turbines, Act adopted in 1994	**SO_2** *Liquid/Gaseous Fuel:* Peaking – 800 g/GJ heat input Non-Peaking – 900 g/GJ heat input *Solid Derived Fuel:* 770 g/GJ input or 90% capture **NO_x** *Gas-Fired:* Peaking - >3 MW 280 g/GJ input Non-Peaking - <3 MW 600 g/GJ input, 3-20 MW 140 g/GJ input, >20 MW 380 g/GJ input *Liquid Fuel:* Peaking - >3 MW 530 g/GJ heat input Non-Peaking - <3 MW 1250 g/GJ input, 3-20 MW 460 g/GJ input, >20 MW 380 g/GJ input (For the purpose of modelling, existing emission rates already account for these regulations and hence were not modeled explicitly.)

[8] Based on National Emission Guidelines for Stationary Combustions Turbines (CEPA)
<u>Note</u>: LQE = <u>Note</u>: LQE = Règlement sur la qualité de l'atmosphère

ON	Regulation 396/01	Ontario Environmental Protection Act	Lakeview Generating Station	After April 30, 2005, coal is not used to generate electricity at the facility and emissions from the facility meet or are better than the emissions performance of a gas-fired electricity generating unit that has an Annual Average Heat Rate of no greater than 12,000 KJ/kW-hour
MB	Federal-Provincial Agreements for Eastern Canada Acid Rain Program	Eastern Canadian Acid Rain Program	Fossil Power Plants, enacted 1994	**SO_2** – Cap 4 kilotonnes
AB	Emissions Standards For New or Expanded Coal-Fired Power Plants	Alberta – Energy and Utilities Board Act	Any coal-fired power plant approved between 2001 and 2005	**PM** – 13ng/J heat input – 720hr Avg. **SO_2** – 180ng/J heat input – 720hr Avg. **NO_x** – 125ng/J heat input – 720hr Avg. (For the purpose of modelling, all new coal-fired power plants will be able to meet the above targets on an annual average basis.)
Canada	National SO2 cap of 3.2 million tonnes by 2000, applied to the electricity sector	Annex 1 (Acid Rain Annex) of the 1991 Canada-U.S. Air Quality Agreement	Fossil Power Plants	**SO_2** – Cap 860.2 kilotonnes
Canada	New Source Emission Guidelines for Thermal Electricity Generation	Canadian Environmental Protection Act, 1999	All new pulverized coal units	All new pulverized coal units have a scrubber and an SCR installed.

Appendix 3.1

Table A.3.1. Model Regions in U.S. EPA IPM Base Case (V 2.1.6)

Model Region	Region Description
AZNM	Western Systems Coordinating Council – AZNMSNV
CALI	Western Systems Coordinating Council – California
DSNY	Downstate New York
ECAO	East Central Area Reliability Coordination Agreement – South
ENTG	Entergy
ERCT	Electric Reliability Council of Texas
FRCC	Florida Reliability Coordinating Council
LILC	Long Island Lighting Company
MACE	Mid-Atlantic Area Council – East
MACS	Mid-Atlantic Area Council – South
MACW	Mid-Atlantic Area Council – West
MANO	Mid-American Interconnected Network – South
MAPP	Mid-continent Area Power Pool
MECS	Michigan Electric Coordination System
NENG	New England Power Pool
NWPE	Western Systems Coordinating Council – Northwest Power Pool East
NYC	New York City
PNW	Western Systems Coordinating Council – Pacific Northwest
RMPA	Western Systems Coordinating Council – Rocky Mountain Power Area
SOU	Southern Company
SPPN	Southwest Power Pool – North
SPPS	Southwest Power Pool – South
TVA	Tennessee Valley Authority
UPNY	Upstate New York
VACA	Virginia – Carolinas
WUMS	Wisconsin-Upper Michigan

Chapter 4: Canadian Module Generating Resources

To represent the Canadian power sector, generating units in the Canadian IPM Base Case 2004 include hydro, nuclear, fossil, biomass, and other non-fossil electricity generating units in three categories: units currently operating, planned-committed units, and potential units. Units that are currently operational are termed existing units. Units that are not currently operating but have either broken ground (initiated construction) or secured financing are termed planned-committed. Potential units refer to new generating options included in the Canadian IPM Base Case 2004 and used by IPM for capacity projections.

Canada's largest source of electricity comes from hydro electrical power and it is an important component of Canada's generation. This has been reflected in the Canadian IPM Base Case 2004. The U,S. EPA IPM model does not include hydro potential, however, the Canadian module takes into account the significance of hydro capacity to meet Canadian electricity demand.

This chapter is organized into six sections. Section 4.1 provides information on the Canadian Module Unit List (CMUL) which serves as the repository for information on existing and planned-committed units that are modeled in the Canadian IPM Base Case 2004. Detailed information on the three categories of generating units modeled in the Canadian IPM Base Case 2004 is presented in Section 4.2 (existing units), 4.3 (planned-committed units), and 4.4 (potential units), with the exception of nuclear. Section 4.5 describes the handling of existing and potential nuclear units in the Canadian IPM Base Case 2004. Section 4.6 discusses the repowering options provided to coal and oil/gas steam generating units under the base case.

4.1 Canadian Module Unit List (CMUL)

The Canadian IPM Base Case 2004 has source data on all currently operating and planned-committed units. This information was included in the Canadian Module Unit List, which is the Canadian equivalent of the U.S. EPA NEEDS database. All unit-level information is available as well as the unit's location (model region and geographical location), capacity, plant type, pollution controls equipment for SO_2 and NO_x, boiler configuration, and SO_2 and NO_x emission rates. Table 4.1 below summarizes the sources used in developing data on existing and planned-committed units in the Canadian Module Unit List.

Table 4.1 Data Sources for the Canadian Module Unit List

Data Source	Data Source Documentation
ATCO. 2002.	Company/ Utility Website
British Columbia (BC) Hydro. 2003.	Company/ Utility Website
British Columbia Hydro. 2004.	Personal Communication.
Canadian Electricity Association (CEA). 2002.	Mercury Program Implementation Plan – Section 4 Annex A General Facility Information Report.
Canadian Electricity Association. 2003.	Company/ Utility Website
Canadian Forest Service (CFS). 1999.	Canada's Wood Residues: A Profile of Current Surplus and Regional Concentrations.
Canadian Hydro Developers	Company/ Utility Website
Canadian Nuclear Association (CNA). 2001.	Nuclear Electricity and Canada's Domestic Response to the Kyoto Protocol: Modeling the Economics of Alternative Scenarios.
Canadian Wind Energy Association (CanWEA):. 2003.	Company/ Utility Website
Cowley Ridge	Company/ Utility Website
Energy Information Administration (EIA). 2002a.	Annual Energy Outlook

Environment Canada. 2003, 2002, 2001.	Personal Communication; Inventory of Landfill Gas Recovery and Utilization in Canada.
Environmental Protection Act.	Ontario Regulations: Lakeview Generating Station. Reg2001.0236.e.
Epcor. 2002.	Company/ Utility Website
Government of Alberta. 2003.	Company/ Utility Website
Hydro Quebec. 2004.	Personal Communication.
Kruger. 2003.	Company/ Utility Website
Manitoba Hydro. 2002.	Personal Communication.
Manitoba Hydro. 2003.	Company/ Utility Website
New Brunswick Power. 2002.	Company/ Utility Website
New Brunswick Power. 2003.	Producing Cleaner Electricity at the Coleson Cove Generating Station.
Newfoundland and Labrador Hydro. 2003.	Company/ Utility Website
North American Electricity Reliability Council (NERC). 2001c.	Electricity Supply and Demand Database Software.
Nova Scotia Power. 2002.	Company/ Utility Website
Nyboer, J. and Pape-Salmon, A. 2003.	A Review of Existing Renewable Energy Facilities in Canada.
Ontario Independent Market Operator. 2002.	Personal Communication.
Ontario Ministry of Environment (MOE). 2001, 2001b.	Coal-Fired Electricity Generation in Ontario; Ontario Regulation 396/01.
Ontario Power Generation (OPG). 2001.	Ontario Power Generation and Babcock & Wilcox Team Up for $200 Million Environmental Project
Ontario Power Generation (OPG). 2002.	Company/ Utility Website
SaskPower. 2002a.	Company/ Utility Website
SaskPower. 2002b.	Personal Communication.
Statistics Canada. 2000b.	Electric Power Generating Stations.
Strickland, C. and Nyboer, J. 2002.	A Review of Existing Cogeneration Facilities in Canada.
TransAlta. 2002.	Company/ Utility Website
U.S. Environmental Protection Agency (EPA). 2002b, 2002c, 2003d.	Documentation of EPA Modelling Applications (V.2.1) Using the Integrated Planning Model; Air Pollution Technology Fact Sheet; National Electric Energy System (NEEDS) Database.
U.S. Environmental Protection Agency (EPA)	Compilation of Air Pollutant Emission Factors AP – 42, Fifth Edition, Volume 1: Stationary Point and Area Sources
U.S. Environmental Protection Agency (EPA) Base Case (V 2.1.6)	Where no information was available from other sources, the assumptions used in the U.S. EPA IPM Base Case (V 2.1.6) were retained to maintain compatibility for joint modelling.
Vision Quest. 2003.	Company/ Utility Website

4.2 Existing Units

The Canadian IPM Base Case 2004 models existing units based on information contained in the Canadian Module Unit List. The sections below describe the specific data sources and procedures followed in determining the population, capacity, plant location, unit configuration, model plant aggregation, and cost and performance characteristics of the existing non-nuclear units represented in the Base Case. Key features of the Base Case representation of these units are also presented.

4.2.1 Population of Units Currently Operating

The population of units currently operating included both on-grid and off-grid units, though units from the Canadian territories were not included in modelling.

The Canadian Module Unit List includes steam units at the boiler level and non-steam units at the generator level. A unit in the Canadian Module Unit List, therefore, refers to a boiler in the case of a steam unit and a generator in the case of a non-steam unit. Table 4.2 below provides a summary of the population statistic of currently operating units included in the Canadian Module Unit List.

Table 4.2. Summary of Population (through 2003) in the Canadian Module Unit List

Plant Type	**Number of Units**	**Capacity (MW)**
Biomass – Wood and Wood Waste	76	1,694.38
Combined Cycle	63	5,189.58
Combustion Turbine	395	4,439.90
Hydro	1333	67,374.65
Landfill Gas	9	13.00
Nuclear	17	12,060
Oil/Gas Steam	110	8,114.11
Fossil – Other	4	25
Other	9	126.50
Pumped Storage (treated as Hydro)	6	174
Scrubbed Coal	1	458
Scrubbed Coal with Selective Catalytic Reduction	2	980
Unscrubbed Bituminous Coal with Selective Catalytic Reduction	2	980
Unscrubbed Coal – Bituminous	22	6,444
Unscrubbed Coal – Lignite	12	2,241
Unscrubbed Coal – Sub-bituminous	17	5,325
Wind	49	330.63
Total	2127	115,970

Note: Table 8.6 outlines the plant types used in the Canadian IPM Base Case 2004.

4.2.2 Capacity

To the extent possible, the Canadian IPM Base Case 2004 uses net capacity in the Canadian Module Unit List. As noted earlier, for steam units the Canadian Module Unit List includes boiler level data, while for non-steam units it contains generator level data.

Since the Canadian IPM Base Case 2004 uses energy demand inputs that include demand served by on-grid and off-grid electricity resources, the Canadian Module Unit List includes both on-grid and off-grid capacity to be consistent with demand.

4.2.3 Plant Location

The Canadian Module Unit List uses province (model region) and geographical coordinates (latitude and longitude) to represent the physical location of plants in the Canadian IPM Base Case 2004. Table 3.1 in Chapter 3 provides a summary of the mapping of model regions in the Canadian IPM Base Case 2004.

4.2.4 Online and Retirement Year

The Canadian IPM Base Case 2004 uses online year to capture when the unit entered service. The Canadian Module Unit List includes online years for all units.

The Canadian IPM Base Case 2004 does not provide retirement year assumptions to coal, oil and gas steam, combined cycle, combustion turbines, and nuclear units. However, economic retirement options are provided to these plants. This means that these units may elect to retire if it is economical to do so. In IPM, an early retired plant ceases to incur FOM and VOM costs. However, retired units do meet capital cost obligations for retrofits if the model projected a retrofit on the unit prior to retirement.

4.2.5 Unit Configuration

Unit configuration refers to the physical specifications of a unit's design. Unit configuration in the Canadian IPM Base Case 2004 drives the model plant aggregation and modelling pollution control options. The Canadian Module Unit List contains information on installed pollution controls for NO_x and SO_2 on all units in the Canadian Module Unit List. Table 4.3 describes the data items used in developing unit configuration in the Canadian Module Unit List.

Table 4.3. Data Items and Description

Data Item	**Description/ Notes**
Unique Unit Code	The unique identifier assigned to a boiler or generator within a power plant.
Electricity Generating Unit (EGU) Name	Name of EGU (will identify the name of each boiler or generator within a power plant).
Online Date	Date the unit became operational.
Province	Province of location.
Plant Type	Indicates type of generation, e.g., combined-cycle, combustion turbine, wood-fired, hydro, etc.
Capacity (MW)	To the extent possible, the capacity characterizes the net power capability of an EGU.
Heat Rate (Btu/kWh and kJ/kWh)	Characterizes the efficiency of a unit.
Existing Emission Controls	Installed and operating NO_x, SO_2, or PM abatement technology.
NO_x Rate (g/MJ)	Characterizes the mass of NO_x emitted per unit of heat input.
SO_2 Rate (g/MJ)	Characterizes the mass of SO_2 emitted per unit of heat input.
Planned Emission Controls	Announced planned NO_x, SO_2, or PM abatement technology.
Fuel Used	Fuel / fuels used by EGU for electricity generation.

4.2.6 Model Plant Aggregations

When compared to the U.S. IPM model, the Canadian IPM Base Case 2004 has very few generating units and as such, model plant aggregations exist only in certain cases. An aggregation scheme clusters real life units into model plants in a fashion similar to that used in the U.S. EPA IPM Base Case version 2.1.6 (http://www.epa.gov/airmarkets/epa-ipm/). The aggregation scheme serves to reduce the size of the model and makes the modelling manageable while capturing the essential characteristics of the generating units.

The Canadian IPM Base Case 2004 includes an aggregation scheme that clusters only certain types of units into model plants based on similarity in characteristics. The aggregation scheme encompasses a variety of different classification categories. These include location, size, technology, efficiency, fuel choices, unit configuration, emission rates and environmental regulations among other. Units are aggregated together only if they match on all the different categories specified for the aggregation. Please refer to section 4.2.6 in the U.S. EPA IPM Base Case (V 2.1) report (http://www.epa.gov/airmarkets/epa-ipm/) for the categories used for the aggregation scheme.

Table 4.4 provides a crosswalk between actual plants and model plants in the Canadian IPM Base Case 2004. If the number of existing units is the same as the number of IPM model plants no aggregation occurred for this type of plant. In fact, only hydro, biomass, wind, landfill gas and non-fossil waste plants were aggregated into IPM model plants.

Table 4.4. Aggregation Profile for Existing and Planned-Committed Model Plants in the Canadian IPM Base Case 2004

Plant Type	**Number of Units**	**Number of IPM Model Plants**
Coal Steam	57	57
Oil/Gas Steam	110	110
Combined Cycle	65	65
Turbine	392	392
Nuclear	20	20
Hydro	1,359	16
Biomass	77	20
Wind	52	6
Landfill Gas	9	2
Fossil Waste	4	4
Non-Fossil Waste	9	7
Total	**2,154**	**699**

The model allows new units to be built or plants can add retrofit technologies, can repower, or even retire. In modelling, IPM model plants have to be available for the model to use in the case of new units, retrofits, repowerings or retirements, and as such are shown in Table 4.5 as IPM model plants. The model has the option of "turning on" these units or not. For example, if the model chooses to build 15 new combined cycle units, 15 of the allotted 22 will be "turned on".

Table 4.5. Aggregation Profile for New Units, Retrofits, Repowerings and Early Retirements in the Canadian IPM Base Case 2004

	Number of Units	**Number of IPM Model Plants**
New Units		
Conventional Pulverized Coal	---	13
IGCC	---	13
Combined Cycle	---	22
Combustion Turbine	---	44
Advanced Combustion Turbine	---	26
Nuclear	---	22
Biomass	---	9
Wind	---	11
Hydro	---	11
Landfill Gas	---	10
Total	**---**	**203**

Retrofits		
Coal to Scrubber Retrofit	---	69
Retrofit Coal to Scrubber + SCR	---	194
Retrofit Coal to Scrubber + SNCR	---	53
Retrofit Coal to Selective Catalytic Reduction (SCR)	---	48
Retrofit to Selective Noncatalytic Reduction (SNCR)	---	18
Retrofit Coal to Activated Carbon Injection (ACI)	---	79
Retrofit Coal to ACI + SCR	---	67
Retrofit Coal to ACI + SNCR	---	84
Retrofit Coal to ACI + Scrubber	---	90
Retrofit Coal to ACI + Scrubber +SCR	---	84
Retrofit Coal to ACI + Scrubber +SNCR	---	9
Retrofit Oil and Gas to SCR	---	95
Retrofit Oil and Gas to SNCR	---	93
Total	---	**924**
Repowerings		
Coal to Combined Cycle Repowering	---	56
Coal to IGCC Repowering	---	56
Oil and Gas to Combined Cycle Repowering	---	105
Total	---	**217**
Early Retirements		
Coal Early Retirement	---	56
Oil and Gas Early Retirement	---	110
Combined Cycle Early Retirement	---	65
Combustion Turbine Early Retirement	---	392
Nuclear Early Retirement	---	20
Total	---	**643**
GRAND TOTAL		**2685**

4.2.7 Cost and Performance of Existing Units

The Canadian IPM Base Case 2004 used heat rate, emission rates, variable operation and maintenance cost (VOM) and fixed operation and maintenance costs (FOM) to characterize the cost and performance of all existing units in the Canadian Module Unit List. For all existing units, the Canadian IPM Base Case 2004 includes only incremental production costs. The embedded costs of existing units, such as carrying capital charges, are not modeled. The section below contains a discussion of the cost and performance assumptions for existing units used in the Canadian IPM Base Case 2004.

Heat Rates and Emission Rates

The treatment of heat rates and emission rates in the Canadian IPM Base Case 2004 was discussed in Section 3.8. Table 3.9 summarizes existing air regulations and the target SO_2 and NO_x emission rates and emissions.

Variable Operating and Maintenance Cost (VOM)

VOM represents the non-fuel cost associated with producing a unit of electricity. If the generating unit contains pollution control equipment, VOM includes the cost of operating the control equipment. Table 4.6 below summarizes VOM assumptions used in the Canadian IPM Base Case 2004.

Table 4.6. VOM Assumptions (1999US$) in the Canadian IPM Base Case 2004

Capacity Type	NO_x Control	Variable O&M (mills/kWh)
Unscrubbed Coal	No NO_x	1.5
	SCR	2.5
	SNCR	2.5
Scrubbed Coal	No NO_x	2.9
	SCR	3.9
	SNCR	3.9
Oil/Gas Steam	No NO_x	2.6
	SCR	2.7
	SNCR	3.0
Combined-Cycle	--	1.0
Combustion Turbines	--	1.0
Nuclear	--	2.0

Fixed Operation and Maintenance Cost (FOM)

FOM represents the annual cost of maintaining a unit. FOM costs are incurred independent of achieved generation levels and signify the fixed cost of operating and maintaining the unit for generation. Table 4.7 summarizes the FOM assumptions used in the Canadian IPM Base Case 2004. Note that FOM varies by the age of the unit. The values appearing in this table include the cost of maintaining any associated pollution control equipment.

Table 4.7. FOM Assumptions (1999US$) Used in the Canadian IPM Base Case 2004

Prime Mover Type	Primary Fuel	NO_x Control	Age of Unit in 1998 (Years)	FOM (1999US$/kW-yr)
Steam Turbine	Coal Unscrubbed	No NO_x Control	0 – 10	11.7
			10 – 20	17.4
			20 – 30	21.4
			Greater than 30	27.0
		SCR	0 – 10	12.2
			10 – 20	18.0
			20 – 30	22.0
			Greater than 30	27.6
		SNCR	0 – 10	11.9
			10 – 20	17.6
			20 – 30	21.6
			Greater than 30	27.2
	Coal Scrubbed	No NO_x Control	0 – 10	23.1
			10 – 20	35.6
			20 – 30	37.7
			Greater than 30	38.0
		SCR	0 – 10	23.7
			10 – 20	36.2
			20 – 30	38.3
			Greater than 30	38.5
		SNCR	0 – 10	23.3
			10 – 20	35.8

			20 – 30	37.9
			Greater than 30	38.1
	Oil & Gas	No NO_x Control	0 – 20	10.7
			20 – 30	14.7
			Greater than 30	16.4
		SCR	0 – 20	11.9
			20 – 30	15.9
			Greater than 30	17.5
		SNCR	0 – 20	11.0
			20 – 30	15.0
			Greater than 30	16.6
Combined Cycle	Oil & Gas	-	0 – 10	13.9
			Greater than 10	14.9
Gas Turbine	Oil & Gas	-	0 – 10	2.8
			10 – 20	2.8
			Greater than 20	6.2
Hydro	Water	-	0 – 30	13.9
			Greater than 30	15.5
Pump Storage	Water	-	All years	6.5
Nuclear	Uranium	-	-	92.3

4.3 Planned-Committed Units

The Canadian IPM Base Case 2004 includes all planned-committed units that are likely to come online before 2007. Like existing units, planned-committed units are contained in the Canadian Module Unit List.

4.3.1 Population

In the Canadian IPM Base Case 2004, a planned-committed unit was included in the Canadian Module Unit List only if it had broken ground (initiated construction) or secured financing and was committed to be online before 2007. The population of planned-committed units in the Canadian Module Unit List was developed using either personal communication with utilities or from company utility websites.

Table 4.8 summarizes the planned-committed unit total capacity in the Canadian IPM Base Case 2004 by unit technology type and model region.

Table 4.8. Planned-Committed Units in the Canadian IPM Base Case 2004 by Model Region

IPM Region	Unit Type	Number of Units	Capacity (MW)
NS	Wind	1	50
QC	Biomass	1	20
QC	Cogeneration – Combustion Turbine	1	550
QC	Hydro	11	4043
ON	Combined Cycle	1	580
ON	Hydro	1	150
ON	Nuclear	3	1533
MB	Hydro	2	480
AB	Biomass	1	25
AB	Cogeneration – Combustion Turbine	1	85
AB	Scrubbed Coal	1	450
AB	Wind	2	130

BC	Hydro	5	390
Total		**31**	**8486**

4.3.2 Capacity

The capacity of planned-committed units in the Canadian Module Unit List was obtained either through personal communication with utilities or from company/utility websites.

4.3.3 Model Region

The location of the planned-committed units was determined also in the same way.

4.3.4 Online and Retirement Year

As noted above, the population of planned-committed units in the Canadian Module Unit List includes only those units that are expected to come online before 2007. All planned-committed units were given a default online year of 2007 since this is the first analysis year in the Canadian IPM Base Case 2004. The assumptions in the Canadian IPM Base Case 2004 do not include a lifetime for planned-committed units.

4.3.5 Unit Configuration and Cost and Performance

All planned-committed units in the Canadian Module Unit List take on the unit configuration and cost and performance characteristics of potential units that are available in 2007. The assumptions for potential units in Canadian IPM Base Case 2004 are discussed in full under Section 4.4.

4.4 Potential Units

The Canadian IPM Base Case 2004 includes options for developing a variety of potential units that may come online at a future date. Defined by region, technology and the year available, potential units with an initial capacity of 0 MW are inputs into IPM. When the model is run, the capacity of certain potential units is raised from zero to meet demand and other system and operating constraints. This results in the model's projection of new capacity.

Table 4.5 gives a breakdown of the number of potential units by plant type that are available for the model to build in the Canadian IPM Base Case 2004. This section describes the cost and performance assumptions for potential non-nuclear units used in the Canadian IPM Base Case 2004. Potential nuclear units are treated below in Section 4.5.2.

4.4.1 Methodology

The Canadian IPM Base Case 2004 is a joint model with both Canada and the U.S.. The model generates projections up to year 2030 and, hence, IPM requires information in regards to detailed cost and performance characteristics of new generating units to meet growing demand and to replace retired capacity. The power plant costs and performance of new generating units were taken from the U.S. Energy Information Administration's (EIA's) "*Annual Energy Outlook 2003*" (AEO) for consistency with the U.S. implementation.

For each new unit type, the following characteristics that are representative of each of the provinces are included:

- Capital Cost ($/kW), including Interest During Construction (IDC),
- Fixed Operating & Maintenance Cost ($/kW-year),
- Variable Operating & Maintenance Cost ($/MWh),
- Heat Rate (Btu/kWh),

- Contribution to reserve margin for non-dispatchable resources, and
- Resource potential for renewable resources.

The engineering and procurement cost (EPC) of developing and building a new plant is captured through the capital cost. AEO 2003 reports overnight capital cost, which does not include interest during construction (IDC). The Canadian IPM Base Case 2004 uses overnight capital cost from AEO and includes IDC in developing the total capital cost for new units. Calculation of IDC is based on the construction profile and the discount rate. Details on the discount rates used in the Canadian IPM Base Case 2004 are contained in Chapter 6 under financial assumptions. The total capital cost includes expenditures on pollution control equipment that new units are assumed to install to satisfy air regulatory requirements.

Once a unit is built, the maintenance and operation cost of a new unit is characterized by the fixed operation and maintenance costs and the variable operation and maintenance cost. Performance assumptions for the new unit are characterized by the heat rate, availability and emission rates.

The capital costs reported in AEO 2003 are generic. Provincial differences in labour rates were applied, as summarized in Table 4.9, to the EIA costs to develop the provincial specific costs for use in the Canadian IPM Base Case 2004.

Table 4.9. Labour Rates and Regional/Provincial Cost Factors

Province	Average Labour Cost ($/hour)	Labour Factor	Factory Equipment Factor	Site Materials Factor	Net Provincial Cost Factor
NF	14.60	0.88	1.00	1.00	0.977
NL	14.60	0.88	1.00	1.00	0.977
PE	11.48	0.69	1.00	1.00	0.939
NS	14.56	0.88	1.00	1.00	0.976
NB	13.80	0.84	1.00	1.00	0.967
QC	15.21	0.92	1.00	1.00	0.984
ON	17.35	1.05	1.00	1.00	1.010
MB	13.64	0.83	1.00	1.00	0.965
SK	15.35	0.93	1.00	1.00	0.986
AB	16.36	0.99	1.00	1.00	0.998
BC	18.22	1.10	1.00	1.00	1.021

Source: Statistics Canada

Notes:

1. The $/hour was estimated by computing the ratio of total hours and total wages in each of the provinces.
2. The labour factor was estimated by the provincial level average labour cost with the Canadian average labour cost.
3. AEO 2003 assumes a breakdown of total engineering and procurement costs (EPC) as follows: 65% factory equipment, 20% site labour, and 15% site materials. All equipment was assumed to be imported and hence was assumed to be available across provinces at the same cost. Due to lack of provincial level information in regards to the cost of site materials, it was assumed that they are available at the same cost across the provinces.

4.4.2 Cost and Performance for Potential Conventional Units

The types of conventional generation technologies that are allowed as new units in the Canadian IPM Base Case 2004 include:

- Coal-fired steam units (Conventional Pulverized Coal),
- Coal-fuelled Integrated Gasification Combined Cycle (IGCC),

- Natural gas-fired Combined Cycle (CC),
- Natural gas-fired Combustion Turbines (CT).

To maintain consistency with the U.S. EPA IPM Base Case version 2.1.6, cost and performance characteristics of new units were based on the AEO 2003 assumptions. These assumptions are summarized in Table 4.10 below. In the U.S. implementation, the reference plant costs from EIA, as summarized in Table 4.10, are regionalized for various U.S. power markets using regional factors that reflect differences in labour and material costs. In the Canadian IPM Base Case 2004, the provincial differences in labour rates as summarized in Table 4.9 above were applied to the EIA costs resulting in provincial specific costs.

Table 4.10. Performance and Unit Cost Assumptions for Potential (New) Capacity from Conventional Fossil Technologies in the Canadian IPM Base Case 2004 (CDN 1999$)

	Conventional Pulverized Coal	Integrated Gasification Combined Cycle	Combined Cycle	Advanced Combustion Turbine	Combustion Turbine
Size (MW)	400	428	400	120	160
First Year Available	2010	2010	2010	2005	2005
Lead Time (years)	4	4	3	2	2
Vintage #1 (years covered)	2010 & after	2010 & after	2010 & after	2005-2009	2005-2009
Vintage #2 (years covered)	N/A	N/A	N/A	2010 & after	2010 & after
Availability	85%	87.7%	90.4%	92.3%	92.3%
Assumed emission controls	Scrubber, SCR[1]	SCR	SCR	None	None
SO_2 Removal	95%	99%	N/A	N/A	N/A
NOx Rate (lbs/MMBtu)	0.11	0.02	0.02	0.08	0.08
Vintage #1					
Heat Rate (Btu/kWh)	8,689	7,378	7,056	9,384	10,930
Capital ($/kW)	1,673	1,958	782	684	607
Fixed O&M ($/kW/year)	36.36	50.01	18.18	12.12	15.13
Variable O&M ($/MWh)	4.55	3.03	3.03	4.55	6.07
Vintage #2					
Heat Rate (Btu/kWh)	N/A	N/A	N/A	8,550	10,450
Capital ($/kW)[2]	N/A	N/A	N/A	580	596
Fixed O&M ($/kW/year)	N/A	N/A	N/A	12.12	15.13
Variable O&M ($/MWh)	N/A	N/A	N/A	4.55	6.07

Notes:
1. In accordance with the New Source Emission Guidelines for Thermal Electricity Generation (published under the Canadian Environmental Protection Act, 1999), it was assumed that all new pulverized coal units have a scrubber and an SCR installed.
2. Capital costs do not include interest during constructions. A conversion rate of 1US$=1.55CDN$ was used.

The cost and performance assumptions in Table 4.10 are based on size (i.e., electrical generating capacity in MW) shown in the table. The total new capacity that can come online for these technologies is not restricted in the Canadian IPM Base Case 2004. Lead time represents the construction time needed for a unit to come online, and availability describes the percent of hours in a year that the unit can operate once it has come online. Vintage groupings capture the cost and performance improvements resulting from technological change and learning-by-doing.

4.4.3 Cost and Performance for Potential Renewable Resource Generating and Non-Conventional Technologies

The types of renewable generation technologies that are allowed as new units in the Canadian IPM Base Case 2004 include:

- Wind
- Small Hydro
- Large Hydro
- Landfill Gas, and
- Biomass

Wind

Wind is one of the more promising renewable technologies that are currently being adopted. Cost and performance characteristics from Energy Information Administration's *Annual Energy Outlook* 2003 were used to maintain consistency with the U.S. implementation. Since the first run of the Canadian IPM Base Case 2004 was 2007 and Natural Resources Canada's Wind Power Production Incentive (WPPI) eligibility requirements end in April 2007, WPPI was not used to offset the capital costs.

Wind resource potential is constrained by geographical variables affecting the quality of wind. Sites for wind energy projects in Canada are limited and, due to the nature of wind as an intermittent energy resource, wind turbines will not continuously generate power. Wind speed and generation profile measurements at various monitoring stations across each province were obtained from the Atmospheric and Environment Service of Environment Canada. Based on the average annual wind speed, the wind quality at each station was assigned a specific "wind class" – a measure of the quality of the wind. Each province was assigned a wind class based on this data. All wind performance data is summarized below in Table 4.11. The capital cost is 1,487$/kW (CDN 1999$) and adjusted for provincial capital cost factor and the interest during construction (IDC). The Fixed Operating and Maintenance cost is 38.70$/kW-year (CDN 1999$). The cost source is the Energy Information Administration, 2003. "Annual Energy Outlook".

Table 4.11. New Wind Units Cost, Capacity Factor and Resource Potential in the Canadian IPM Base Case 2004

Province	Capacity Factor	Resource Potential (MW)
NF	0.42	611
NL	0.34	611
PE	0.34	43
NS	0.42	574
NB	0.34	785
QC	0.42	9,777
ON	0.42	8,236
MB	0.34	1,027
SK	0.42	826
AB	0.42	2,509
BC	0.42	3,257

Resource Potential Source: CANMET; Energy, Mines and Resources; October 1992.

Small Hydro

Although small hydro potential is not an explicit option that is modeled in the U.S. implementation, it is an important part of Canada's power sector and the assumptions were developed for Environment Canada to be used in the Canadian IPM Base Case 2004. These assumptions were based on the CANMET International Small Hydro Atlas, 2002. The International Small Hydro Atlas provided estimates on the costs and potential for undeveloped small hydro locations. Cost information was obtained for Canada, specific to each province and is based on data collected over the last 20 years. The site specific cost information is based on established formulae and individual studies incorporated into the database. In order to represent the cost and potential in each province on an aggregate basis in the model, four cost classes were developed (very low, low, medium, and high cost) by ICF Consulting Canada. They reflect the weighted average cost of all potential sites in each designated class. Table 4.12 and Table 4.13 specify the capital cost and the corresponding resource potential for small hydro by province and cost class.

Table 4.12. Summary of Small Hydro Capital Costs in the Canadian IPM Base Case 2004 (CDN 1999$/kW)

	Small Hydro			
Province	**Very Low**	**Low**	**Medium**	**High**
NF	N/A	2,415	3,143	4,146
NL	N/A	4,177	4,693	6,021
PE	N/A	N/A	N/A	N/A
NS	2,717	3,139	3,643	4,657
NB	2,822	3,652	4,654	5,937
QC	2,005	2,696	3,402	4,593
ON	1,521	2,208	2,675	3,145
MB	3,275	3,929	4,507	5,145
SK	4,800	6,578	N/A	N/A
AB	2,869	3,170	3,791	5,728
BC	N/A	1,730	2,425	4,830

Table 4.13. Small Hydro Resource Potential in the Canadian IPM Base Case 2004 (MW)

	Small Hydro			
Province	**Very Low**	**Low**	**Medium**	**High**
NF	0	395	396	400
NL	0	6	6	6
PE	N/A	N/A	N/A	N/A
NS	1	54	55	54
NB	0	186	180	174
QC	19	347	363	353
ON	0	58	59	54
MB	14	101	117	100
SK	12	13	N/A	N/A
AB	19	39	48	32
BC	0	286	290	286

Source: CANMET Energy Technology Centre, Natural Resources Canada. 2002. International Small Hydro Atlas.

Energy availability at small hydro generators often varies greatly across provinces. It is necessary to represent these seasonal differences in the model. CANMET's International Small Hydro Atlas provides data on site-specific capacity factors for a range of small hydro projects. The Atlas focuses on installations between 5 kW and 20 MW. The annual capacity factors are seasonalized based on existing provincial hydro capacity factors. These capacity factors are summarized in Table 4.14 below.

Table 4.14. Seasonal Small Hydro Capacity Factors in the Canadian IPM Base Case 2004

		Seasonal Capacity Factor	
Province	**Type**	**Winter**	**Summer**
Newfoundland	Very Low	N/A	N/A
	Low	0.68	0.43
	Medium	0.72	0.47
	High	0.73	0.48
Labrador	Very Low	N/A	N/A
	Low	0.68	0.43
	Medium	0.72	0.47
	High	0.73	0.48
Nova Scotia	Very Low	0.53	0.44
	Low	0.57	0.49
	Medium	0.54	0.46
	High	0.55	0.47
New Brunswick	Very Low	0.49	0.48
	Low	0.48	0.47
	Medium	0.54	0.53
	High	0.56	0.55
Quebec	Very Low	0.86	0.75
	Low	0.80	0.69
	Medium	0.77	0.66

	High	0.79	0.68
Ontario	Very Low Low Medium High	0.55 0.64 0.61 0.60	0.50 0.59 0.56 0.55
Manitoba	Very Low Low Medium High	0.65 0.65 0.65 0.64	0.65 0.65 0.65 0.63
Saskatchewan	Very Low Low Medium High	0.57 0.63 N/A N/A	0.60 0.67 N/A N/A
Alberta	Very Low Low Medium High	0.37 0.37 0.42 0.40	0.47 0.47 0.52 0.49
British Columbia	Very Low Low Medium High	N/A 0.62 0.59 0.59	N/A 0.53 0.51 0.50

Source: CANMET Energy Technology Centre, Natural Resources Canada. 2002. International Small Hydro Atlas.

Large Hydro

Although large hydro potential is not modeled in the U.S. implementation, it is an important component of Canada's generation and it is included in the Canadian module. Due to the site-specific nature of large hydro projects and the lack of site-specific cost information in addition to the potential for decision-making influenced by a range of objectives, large hydro is not modeled endogenously in the Canadian IPM Base Case 2004. It is modeled exogenously. Table 4.15 summarizes the large hydro projects that were exogenously modelled based on information derived through both personal communication with utilities and utility/communication websites.

Table 4.15. Large Hydro Projects in the Canadian IPM Base Case 2004

Project Name	Province	Capacity (MW)	Online Year
Eastmain 1 (2008)	QC	480	2007
Grand-Mere	QC	220	2005
La Romaine	QC	1500	2014
Mercier	QC	50	2007
Peribonka	QC	385	2008
Sainte-Marguerite – 3	QC	882	2004
Tolnustoouc	QC	526	2005
Additional Hydro Capacity to meet IPM Capacity Requirements[9]	QC	2000	2020
Kelsey	MB	280	2008
Wuskwatim	MB	200	2010
Brilliant Expansion	BC	120	2007

[9] To meet electricity demand, 2000 MW of hydro capacity was exogenously added in Quebec.

Fourth Turbine, Seven Mile	BC	210	2005

Landfill Gas

Information for the Canadian IPM Base Case 2004 on the cost and potential of landfill gas capture and utilization is based on the data collected in a study prepared for Environment Canada entitled "Identification of Potential Landfill Sites for Addition Gas Recovery and Utilization in Canada", 1999 and summarized in Table 4.16 below. A weighted average cost was calculated for each province based on the estimated generation potential. The heat rate is based on U.S. experience and is assumed to be 13,648 Btu/kWh.

Table 4.16. Landfill Gas Capital Costs and Potential in the Canadian IPM Base Case 2004

Province	Cost (CDN 1999$/kW)	Potential (MW)
NF	2,449	7
NL	2,449	7
PE	N/A	N/A
NS	1,665	5
NB	2,926	3
QC	1,812	50
ON	1,850	153
MB	1,800	20
SK	2,339	4
AB	1,973	46
BC	1,452	59

Source: Environment Canada. 1999. "Identification of Potential Landfill Sites for Additional Gas Recovery and Utilization in Canada". Ottawa.

Biomass

The cost and performance characteristics for biomass in the Canadian IPM Base Case 2004 were taken from EIA AEO 2003. The capital cost, fixed O&M and variable O&M were assumed to be $2,615/kW, $68.13/kW-year and 4.39 mills/kWh respectively. All costs are in 1999 CDN dollars. The biomass potential is provided in Table 4.17 and is estimated based on the heat content of the fuel as specified in the *Opportunities for Increased Cogeneration in the Pulp and Paper Industry*, March 1999.

Table 4.17. Biomass Potential in the Canadian IPM Base Case 2004

Province	Wood Waste 2010 (PJ)	Pulp & Spent Liquor 2010 (PJ)	Resource Potential (MW)
NF	3.8	2.2	137
NL	0	0	0
PE	0	0	0
NS	24.0	32.6	233
NB	24.0	32.6	576
QC	42.4	74.6	1,671
ON	18.1	64.9	1,186
MB	3.1	14.2	126
SK	3.1	14.2	121
AB	21.3	48.9	1,003

BC	67.6	219.5	4,101

Notes: Assumes a heat rate of 8911 Btu/kWh and a capacity factor of 85%.
Source: "*Opportunities for Increased Cogeneration in the Pulp and Paper Industry*", March, 1999, prepared for Natural Resources Canada by Neill and Gunter (Nova Scotia) Limited.

4.5 Nuclear Units

4.5.1 Existing Units

Population, Plant Location, Unit Configuration, Online and Retirement Year

The Canadian IPM Base Case 2004 includes model plants representing the 17 currently operating nuclear units and 3 planned-committed nuclear units in the Canadian Module Unit List. The data was obtained primarily from Statistics Canada or the Utility Website. A list of the currently operating and planned-committed nuclear units in the Canadian Module Unit List and their key characteristics is presented in Appendix 4.1.

Capacity

Nuclear units are baseload power plants with high fixed (capital and fixed O&M) costs and low variable (fuel and variable O&M) costs. Due to their low VOM and fuel costs, nuclear units are run to the maximum extent possible, i.e., up to their availability. Consequently, as explained in section 3.5.2, a nuclear unit's capacity factor is equivalent to its availability. Thus, the Canadian IPM Base Case 2004 uses capacity factor assumptions to define the upper bound on generation from nuclear units.

Table 4.18 presents the nuclear capacity factors resulting under the Canadian IPM Base Case 2004. Since the capacity factors for individual plants vary in accordance with the assumptions discussed above and the plants within each region are unique, the average nuclear capacity factors displayed in this table vary by region.

Table 4.18. Average Regional Nuclear Capacity Factors in the Canadian IPM Base Case 2004

IPM Region/ Year	2005-2020
NB	83.6%
QC	79.4%
ON	79.5%
National Weighted Average	79.7%

Cost and Performance

Unlike non-nuclear existing units discussed in Section 4.2.7, emission rates are not used to characterize nuclear units, since there are no SO_2 or NO_x emissions from nuclear units.

As with other generating resources, the Canadian IPM Base Case 2004 uses variable operation and maintenance (VOM) costs and fixed operation and maintenance (FOM) costs to characterize the cost of operating nuclear units. As indicated in Table 4.6, a VOM cost of 2.0 mills/kWh is assumed for nuclear units in the Canadian IPM Base Case 2004. The VOM includes a 1.0 mill/kWh adder to account for the cost of nuclear waste disposal. As indicated in Table 4.7, the FOM cost of 92.3 US$/kW-yr is assumed for nuclear units in the Canadian IPM Base Case 2004. The nuclear fuel cost assumptions in the Canadian IPM Base Case 2004 are presented in Section 7.5.

The Canadian IPM Base Case 2004 offers the option of early retirement to nuclear units based on economic factors. The cost of decommissioning a nuclear unit is not taken into account in the retirement decision.

4.5.2 Potential Nuclear Units

In modelling potential nuclear units, the Canadian IPM Base Case 2004 adopts the cost and performance assumptions associated with building CANDU 6 and ACR-700 units in Canada, based on “Levelised Unit Electricity Cost Comparison of Alternate Technologies for Baseload Generation in Ontario", Canadian Energy Research Institute, August 2004, (http://www.cna.ca/pdf/CERI_LUEC_Report_August_27_2004-ed.pdf)

Nuclear fuel costs for potential units are the same as for existing nuclear units and are presented in Section 6.5. The capacity to model new nuclear units and the cost and performance assumptions are built into the Canadian IPM Base Case 2004.

4.6 Repowering Options

The Canadian IPM Base Case 2004 provides coal steam units the option to repower to natural gas combined cycle and to IGCC. Oil-gas steam units are provided the option to repower to natural gas combined cycle units. These are the only repowering options provided in the Canadian IPM Base Case 2004. Units elect to repower in the model only if it is economic to do so.

In the Canadian IPM Base Case 2004, the cost and performance of a new combined cycle unit (described in Section 4.3.2 above) served as a starting point in developing the cost and performance assumptions for repowering to combined cycle. Similarly, the cost of a new IGCC was used to develop the cost for repowering coal to IGCC. Relative to new units, the cost of re-powering is adjusted down to reflect the fact that there is a cost saving from not having to replace the steam turbine of the existing units and increased to reflect the demolition costs. Repowering, however, is slightly less expensive than a new unit but is also less efficient. Since the repowered unit is not optimized in design of space like a new unit, the heat rate of a repowered unit is assumed to be greater than the heat rate of new unit to reflect the loss in efficiency. For example, the assumed heat rate of 7687 Btu/kWh for a coal unit repowered to IGCC for 2010 and beyond is greater than the 7,378 Btu/kWh, the heat rate for a new IGCC over the same period as shown in Table 4.10.

Please refer to Table 5.5 in Chapter 5 on Emission Control Technologies for a summary of the cost and performance assumptions on repowering in the Canadian IPM Base Case 2004. Table 4.5 above enumerates the repowering options built into the Canadian IPM Base Case 2004.

Appendix 4.1

Table A.4.1. Currently Operating and Planned-Committed Nuclear Generating Units in the Canadian IPM Base Case 2004

Model Region	Number of Units	Capacity (MW)
NB	1	635
QC	1	680
ON	18	12,278
Total	20	13, 593

Chapter 5: Canadian Module Emission Control Technologies

The Canadian IPM Base Case 2004 includes emission control technologies as compliance options for meeting existing air regulations in the IPM modelling framework. The cost and performance characteristics of these technologies for controlling SO_2 and NO_x are based on the U.S. EPA IPM Base Case version 2.1.6 assumptions. This allows the assumptions to be consistent between the two implementations. Detailed equations for the cost and performance characteristics of emission control technologies are summarized in the US EPA's document *Documentation of EPA Modeling Applications (V.2.1) Using the Integrated Planning Model, March 2002 at* (www.epa.gov/airmarkets/epa-ipm).

SO_2 and NO_x control technologies are offered as retrofit options that existing units may utilize to comply with modeled air regulations. Both existing and potential (new) units in the Canadian IPM Base Case 2004 use the same cost and performance assumptions for SO_2 control technologies that are included in the total capital, fixed and variable operations costs of the units. Since cost estimates for potential (new) pulverized coal units based on Annual Energy Outlook (AEO) 2003 already include SO_2 scrubber costs, no additional cost adjustments were assumed for SO_2 reduction for potential pulverized coal units.

5.1 Sulphur Dioxide Control Technologies

Sulphur dioxide control technologies, called flue gas desulphurisaton (FGD's), are known collectively as scrubbers. The two types of scrubbers that were included in this analysis to reduce emissions from coal-fired units are: Limestone Forced Oxidation (LSFO) for power plants burning high sulphur coals, and Lime Spray Drying (LSD) for power plants burning low sulphur coal.

5.1.1 Limestone Forced Oxidation (LSFO)

Limestone Forced Oxidation (LSFO) is a wet SO_2 scrubber technology that is offered to coal units that are greater than 100 MW in size and burn bituminous coals with a 2 percent or higher sulphur content. The LSFO is assumed to provide 95% SO_2 removal.

5.1.2 Lime Spray Drying (LSD)

Lime Spray Drying (LSD) is a dry SO_2 scrubber technology that is offered to coal units that burn bituminous, sub-bituminous, or lignite coals that have less than 2 percent sulphur content. It is assumed in the Canadian IPM Base Case 2004 that LSD technology reduces SO_2 emissions by 75 percent.

The power required to operate each of the scrubbers reduces the capacity and energy available to meet electricity demand. Therefore, a 2.1 percent capacity penalty is applied to each retrofitted unit's original capacity, thereby reducing total generation by 2.1 percent, all else equal. In order to capture the fuel consumed by the scrubber (and therefore its cost of operation), a 2.1 percent heat rate penalty is applied to retrofitted units. This "heat rate penalty" is a modelling procedure only and does not represent an increase in the unit's actual heat rate (i.e., a decrease in the unit's generation efficiency).

5.2 Nitrogen Oxides Control Technology

The Canadian IPM Base Case 2004 includes two categories of NO_x reduction technologies: combustion and post-combustion controls. Combustion controls reduce NO_x emissions during the combustion process by regulating flame characteristics such as temperature. Post-combustion controls operate downstream of the combustion process and remove NO_x from the flue gas. All the specific combustion and post-combustion technologies included in the Canadian IPM Base Case 2004 are commercially available and currently in use in numerous power plants.

5.2.1 Combustion Controls

The Canadian IPM Base Case 2004 makes an exogenous assumption that if units are affected by a NO_x regulation and they do not have any combustion NOx control like Low NO_x Burners or post-combustion controls, these units will put on combustion controls first to comply with the NO_x regulation before putting on post-combustion controls. The NOx emission rates for these units will be adjusted to reflect the adoption of NOx combustion controls.

5.2.2 Post-Combustion Controls

The Canadian IPM Base Case 2004 includes two post-combustion control technologies: Selective Catalytic Reduction (SCR) and Selective Non-Catalytic Reduction (SNCR). These two post-combustion controls are available to coal and oil/gas steam units for control of NOx emissions.

In the Canadian IPM Base Case 2004, both Selective Catalytic Reduction (SCR) and Selective Non-Catalytic Reduction (SNCR) are available to coal and oil/gas steam units for control of NO_x emissions. SCR is available to coal units that are 100 MW or greater in capacity, and to all oil/gas units. An SCR is assumed to achieve a 90 percent reduction in NO_x emissions on a coal-fired unit, to a limit of 0.02 kg/MMBtu. Reductions achieved on oil/gas steam units are 80 percent. An SNCR is assumed to achieve a 35 percent reduction in emissions on coal-fired units and a 50 percent reduction on an oil/gas unit.

Table 5.1 below provides a summary of the cost and performance assumptions for SO2 and NOx emission control technologies for a representative 300 MW Coal Plant with a 10,000 Btu/kWh Heat Rate.

Table 5.1 Summary of Emission Control Technologies Cost and Performance for a Representative 300 MW Coal Plant with a 10,000 Btu/kWh Heat Rate

Emission Control Technology	Specified Pollutant	Capital ($/kW)	Fixed O&M ($/kW/Yr)	Variable O&M (mills/kWh)	Percent Removal
SCR	NO_x	$117.80	$0.77	0.96	90%[1]
SCR – Oil/Gas	NO_x	$40.30	$1.22	0.10	80%
SNCR (Low NO_x Rate[2])	NO_x	$21.70	$0.31	0.86	35%
SNCR (High NO_X Rate—Cyclone)	NO_x	$7.75	$0.12	1.30	35%
SNCR (High NO_x Rate—Other)	NO_x	$13.95	$0.23	0.903	35%
SNCR – Oil/Gas	NO_x	$12.40	$0.18	0.46	
LSFO	SO_2	$446.40	$16.74	1.02	95%
LSD	SO_2	$318.00	$11.3	3.13	75%

Notes:
[1] Low NO_x is < 0.5 lbs/MMBtu. High NO_x is > 0.5 lbs/MMBtu.
[2] Cannot provide reduction any further beyond 0.05 lbs/MMBtu.
[3] VO&M = 0.90 for MW ≤ 480,
VO&M = 0.91 for MW > 480.
All dollar values in year 2000 CDN

Reference:
EPA. Documentation of EPA Modelling Applications (V.2.1) Using the Integrated Planning Model (EPA, 2002b)

5.3 Repowering Options

The Canadian IPM Base Case 2004 provides coal steam units the option to repower to natural gas combined cycle and to IGCC. Oil-gas steam units are provided with the option to repower to natural gas combined cycle units. These are the only repowering options provided in the Canadian IPM Base Case 2004. These assumptions are consistent with the U.S. EPA IPM Base Case version 2.1.6. Table 5.5 summarizes the cost and performance assumptions for the repowering options available to plants in the Canadian IPM Base Case 2004.

Table 5.2 Cost and Performance Assumptions for Repowering Options (CDN 1999$)

	Repower Coal to Coal IGCC	**Repower Coal to Gas Combined Cycle**	**Repower Oil/Gas to Gas Combined Cycle**
Size (MW)	428	400	400
First Year Available	2010	2005	2005
Lead Time (Years)	4	3	3
Vintage #1 (Years Covered)	2010 and after	2005 and after	2005 and after
Availability	87.7%	90.4%	90.4%
Vintage #1			
Repowering Ratio	100%	100%	100%
Heat Rate (Btu/kWh)	7,687	7,220	7,220
Capital ($/kW)	2,063	685	685
Fixed O&M ($/kW-yr)	50.0	18.2	18.2
Variable O&M ($/kW-yr)	3.03	3.03	3.03

Chapter 6: Canadian Module Financial Assumptions

Two parameters, capital charge rate and the discount rate, encapsulate the financing assumptions for an investment option in IPM. The discount rate[10] is necessary for calculation of net present value (NPV). It allows for inter-temporal analysis and represents the time value of money. Annualized capital payments for an investment are computed using the capital charge rate, which takes into account the cost of debt, return on equity, taxes and depreciation.

The Canadian IPM Base Case 2004 includes divergent technologies that have different methods of operation, financing, revenue streams, depreciation schedules and risk profiles. Assumptions about the capital charge rate and discount rate in the Canadian IPM Base Case 2004 reflect these differences and are both technology-specific and province-specific.

For information on the role of the discount rate in IPM, please see Sections 2.3.3 and 2.2. Similarly, for more information about the capital charge rate and its role in IPM, please see Section 2.2. The discussion below describes the methodology and assumptions on the capital charge rate and discount rate in the Canadian IPM Base Case 2004.

6.1 Methodology

In the Canadian IPM Base Case 2004, the capital charge rate and discount rate were based on valuation techniques used in capital markets. Such a capital charge rate and discount rate allows new investments in IPM to be analyzed in the context of deregulated electricity markets where investors and power plant developers have to compete in capital markets for their investments without guaranteed returns on their investments. This assumption for capital charge rate and discount rate was implemented because almost all provinces in Canada allow non-crown corporations to build capacity. This assumption is consistent with the U.S. implementation of IPM.

Free Cash Flow to Firm (FCFF) is a valuation technique used for firms where claim-holders include both debt and equity holders. The cash flows remaining after meeting operating expenses and taxes but before making payments to any claim-holders is the free cash flows to the firm. The capital charge ensures that there is enough free cash flow to the firm to meet the obligation to the debt and equity holders.

Under the Canadian IPM Base Case 2004, the capital charge rate and discount rate primarily serve to provide meaningful insights into the impacts of environmental policies on electricity markets. As a result, a representative investor for purposes of the Canadian IPM Base Case 2004 cannot reflect only the perception of the equity investor or bondholder. Rather the representative investor must be composite of both bondholders and equity holders. As a result, FCFF was used for deriving the capital charge rate and discount rate in the Canadian IPM Base Case 2004.

In the derivation of the assumptions, the capital charge rate is a function of the following parameters:

- Capital structure (Debt/Equity shares of an investment)
- Pre-tax debt rate (or interest cost)
- Debt Life
- Post-tax Return on Equity
- Other costs such as property taxes, insurance and working capital
- Federal and Provincial corporate income taxes
- Depreciation Schedule
- Book Life

Similarly, the discount rate is a function of the following parameters:

[10] The discount rate in the Canadian IPM Base Case 2004 is the Weighted Average Cost of Capital (WACC), which is the discount rate when using the Free Cash Flow to Firm (FCFF) valuation technique described later in this section.

- Capital structure
- Pre-tax debt rate
- Post-tax equity rate

6.2 Capital Charge Rates and Discount Rates

In the Canadian IPM Base Case 2004, the capital charge rate and discount rate vary by province and generation technology. Provinces have different power market structures, provincial taxes and other costs (primarily local and provincial property taxes). It was assumed that all new investments across provinces are made by deregulated entities, as explained in Section 6.1.

6.2.1 Risk Profile and Financing Scheme

When deregulated entities make investments in new units, the investments are typically project financed. This type of financing scheme protects the parent company from putting the assets of the parent company at risk on account of the project. Instead, only the project is at risk. This also implies that the projects are financed based solely on the merits of the project in question – elements such as strength of the parent company, the yield on the company bonds and the returns it offer are less relevant. The market values and finances the investment solely on the basis of the project's fundamentals. Retrofits, however, may be financed through the balance sheet. For the Canadian IPM Base Case 2004, balance sheet financing of retrofits occurs mainly in regulated regions. In such instances, and when data was available, capital structure of the representative utility was used. In deregulated regions, retrofits may still be balance sheet financed, but the financing will adopt the capital structure as if under project finance. This is because, unlike regulated regions, the investment must still be valued in terms of the project fundamentals and the lower debt and equity costs represent lower risk.

It has been observed that Canadian companies raise capital at a corporate level and hence the premise of using debt rates based on risk profiles of an investment might not hold true in Canada. An observation was also made that entities other than large provincial utilities can also develop a project. If this observation is taken to its logical conclusion then we could have an entity that holds a portfolio of only one power plant. In such a case, both balance sheet and project financings should provide similar results. In addition, not all developers in a deregulated market might have access to subsidized capital. In the IPM modelling, the capacity prices are affected by the cost of building the marginal unit, which might not necessarily be built by a provincial utility. Hence, in order to model capacity prices, the risk-based project financing assumption is appropriate. The methodology for developing these financial assumptions is consistent with the assumptions made in the U.S. EPA IPM Base Case version 2.1.6.

Though all regions have the same new unit structure in terms of financing, discount rate and capital charge rate are different across the regions and technologies. The differences across regions result from underlying differences in some parameters such as the tax rate. On the other hand, differences across technologies reflect variations in risk profile embodied by the project.

In deregulated regions capital investments in generation technologies incorporate the investment risk profile unique to that particular technology. Generation technologies differ in their investment risk profiles because of their operational characteristics. For instance, an investment in a combustion turbine (CT) is likely to be much more risky than an investment in a combined cycle (CC) because while a CT operated as a peaking unit and is able to generate revenues only in times of high demand, a CC is able to generate revenues over a much larger number of hours in a year. An investor in a CC, therefore, would require a lower risk premium than an investor in a CT. Similarly, an investment in a combined-heat-and-power plant (CHP) is likely to have a risk profile similar to that of a CC because a large portion of the CHP risk will be mitigated by a steam purchase contract. Since investment in new power plants and CHP sources differ in their risk profile, the discount rate and capital charge rate are differentiated among the different classes of potential units. Two different risk profiles were used for generation technologies in deregulated regions. Technology risk classes do not apply to regulated regions because it was assumed that the same return is guaranteed for all technologies. Table 6.1 describes the risk classes and financing for deregulated regions. The last column of the table refers to the two financing approaches discussed earlier in this section: “Balance Sheet” indicates the use of balance sheet financing; “Project” indicates financing on a project basis.

Table 6.1. Risk Profile Assumptions for Unit Types in the Canadian IPM Base Case 2004

Generation Technology	Risk Class	Financing
Retrofits of Existing Units	Low	Balance Sheet
New Combined Cycle	Medium	Project
New Coal	Medium	Project
New Hydro	Medium	Project
New Nuclear	High	Project
New Combustion Turbine	High	Project
New Non-Hydro Renewable	High	Project

6.2.2 Assumptions

As described above, derivation of the capital charge rate and discount rate requires estimates of various parameters. Some of these parameters are common to all regions and technologies, while others vary by region and/or technology. Summarized in Tables 6.2a-6.2i are the specific assumptions for the capital charge rate and discount rate, by region and technology. The capital charge rate and the discount rate have been developed based on “Expert” input from federal government departments as well as US EPA Base Case V 2.1.6 assumptions.

Table 6.2a. Financial Assumptions for Newfoundland-Labrador

Parameter	Existing + Retrofit	New Wind	New Coal, CC	New Hydro	New CT, Nuclear
Real Capital Charge Rate	10.30%	13.61%	13.14%	11.95%	13.89%
Real Discount Rate	5.34%	8.28%	7.66%	7.66%	8.28%

Table 6.2b. Financial Assumptions for New Brunswick – Prince Edward Island

Parameter	Existing + Retrofit	New Wind	New Coal, CC	New Hydro	New CT, Nuclear
Real Capital Charge Rate	11.58%	14.92%	14.44%	13.25%	15.20%
Real Discount Rate	5.11%	8.27%	7.64%	7.64%	8.27%

Table 6.2c. Financial Assumptions for Nova Scotia

Parameter	Existing + Retrofit	New Wind	New Coal, CC	New Hydro	New CT, Nuclear
Real Capital Charge Rate	12.67%	16.52%	16.07%	14.84%	16.83%
Real Discount Rate	4.60%	8.22%	7.60%	7.60%	8.22%

Table 6.2d. Financial Assumptions for Quebec

Parameter	Existing + Retrofit	New Wind	New Coal, CC	New Hydro	New CT, Nuclear
Real Capital Charge Rate	10.49%	13.99%	13.48%	12.36%	14.19%
Real Discount Rate	4.98%	8.45%	7.81%	7.81%	8.45%

Table 6.2e. Financial Assumptions for Ontario

Parameter	Existing + Retrofit	New Wind	New Coal, CC	New Hydro	New CT, Nuclear
Real Capital Charge Rate	16.21%	17.77%	19.49%	19.26%	17.61%
Real Discount Rate	5.37%	7.71%	8.33%	8.33%	7.71%

Table 6.2f. Financial Assumptions for Manitoba

Parameter	Existing + Retrofit	New Wind	New Coal, CC	New Hydro	New CT, Nuclear
Real Capital Charge Rate	10.70%	12.76%	12.32%	11.07%	13.08%
Real Discount Rate	6.25%	8.22%	7.60%	7.60%	8.22%

Table 6.2g. Financial Assumptions for Saskatchewan

Parameter	Existing + Retrofit	New Wind	New Coal, CC	New Hydro	New CT, Nuclear
Real Capital Charge Rate	13.41%	15.57%	15.15%	13.91%	15.91%
Real Discount Rate	6.22%	8.18%	7.57%	7.57%	8.18%

Table 6.2h. Financial Assumptions for Alberta

Parameter	Existing + Retrofit	New Wind	New Coal, CC	New Hydro	New CT, Nuclear
Real Capital Charge Rate	13.02%	15.04%	14.59%	13.39%	15.34%
Real Discount Rate	6.35%	8.33%	7.70%	7.70%	8.33%

Table 6.2i. Financial Assumptions for British Columbia

Parameter	Existing + Retrofit	New Wind	New Coal, CC	New Hydro	New CT, Nuclear
Real Capital Charge Rate	13.84%	17.40%	16.94%	15.76%	18%

Real Discount Rate	5.0%	8.3%	7.7%	7.7%	8.3%

6.3 Discount Rate for Non-Capital Costs

6.3.1 Fuel, VOM, and FOM Costs

The discount rate for non-capital expenditures (e.g., annual fuel, variable operations and maintenance, and fixed operations and maintenance costs) was assumed to be (5.34%). This serves as the default discount rate for all non-capital expenditures.

6.3.2 Inter-temporal Allowance Price Calculation

Under a perfectly competitive cap-and-trade program that allows banking, the allowance price always increases by the discount rate between periods if affected sources have allowances banked between those two periods. This is a standard economic result for cap-and-trade programs and prevents sources from profiting by arbitraging allowances between the two periods. This calculation is not applicable to the Canadian IPM Base Case 2004.

6.4 Treatment of Nominal and Real Dollars in IPM

The Canadian IPM Base Case 2004 uses real 1999 dollars for all its simulations in IPM. See Chapter 2 for further discussion on how IPM uses the real dollars for inter-temporal analysis.

6.5 Treatment of the Canadian Dollar

An exchange rate of 1.55 CDN$ / US$ was used in the Canadian IPM Base Case 2004. The Canadian IPM Base Case 2004 provides cost and price output in US dollars and the exchange rate is used to convert these IPM cost outputs into Canadian dollars. Any possible information generated in Canada was converted to US$ based on this exchange rate.

Chapter 7: Canadian Module Fuel Assumptions

Fuels are one of the key fundamentals that affect the power sector. Fuel quality directly affects SO_2 emissions. Fuel costs are the largest component of a generating unit's variable cost. Hence, fuel prices influence a generating unit's dispatch characteristics. IPM has the capability to model fuel markets in significant detail. Each generating unit can be provided with multiple fuel supply options in terms of fuel type and quality and the model will dispatch a unit that can generate power at least cost while satisfying fuel and environmental restrictions.

The Canadian IPM Base Case 2004 includes assumptions on coal, natural gas, oil, ORIMULSION®, biomass and nuclear fuels. These assumptions pertain to fuel characteristics, fuel market structure and fuel prices.

7.1 Coal

The Canadian IPM Base Case 2004 deals with coal in two different ways. The first method pertains to provinces such as Alberta and Saskatchewan, which use significant local coal supplies. The second method applies to provinces that import their coal, from the U.S. or from other Canadian provinces. The methods for obtaining coal differ, as well as the cost and grade assumptions. Alberta and Saskatchewan are dealt with first in this section.

Canada has approximately 17 GW of coal plant capacity distributed across the provinces. Table 7.1 below summarizes the provincial level coal capacity.

Table 7.1. Provincial Coal-Fired Capacity in the Canadian IPM Base Case 2004 (MW)

Province	Bituminous	Sub-bituminous	Lignite
Nova Scotia	1,226	N/A	N/A
New Brunswick	60	458	N/A
Ontario	6,973	N/A	525
Manitoba	N/A	100	N/A
Saskatchewan	N/A	N/A	1,716
Alberta	145	5,675	N/A

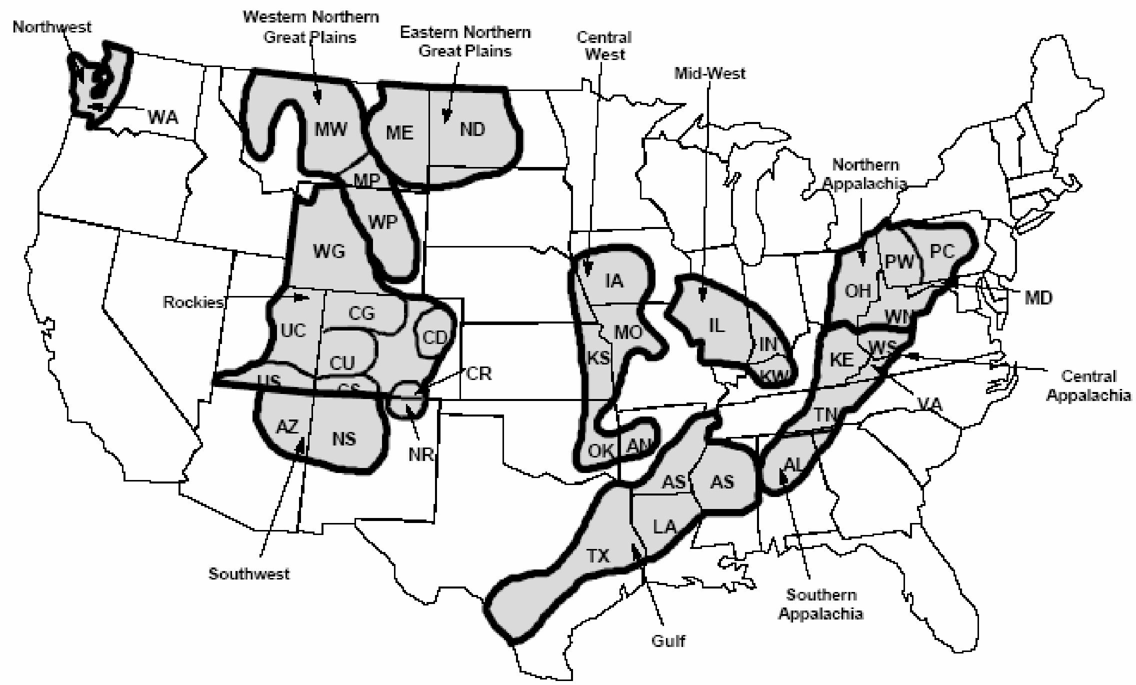
The provinces of Alberta and Saskatchewan have significant local coal resources. Alberta produces mainly sub-bituminous coal and Saskatchewan produces lignite coal. Most of the coal-fired power generation capacity within these provinces is mine mouth in nature and consumes these local coal resources. Because of the mine mouth nature of the coal plants, the likelihood of switching to coal with different characteristics can be considered to be remote and hence, coal plants in Alberta and Saskatchewan will be provided with only the mine mouth coal options. In addition, coal based generation is not considered likely in Quebec due to the large undeveloped hydro capacity and is therefore not allowed in the Canadian IPM Base Case 2004.

The coal power plants in the remaining provinces as well as the details of the coal market assumptions in the Canadian IPM Base Case 2004 will be discussed in Section 7.1.1 below. The Canadian IPM Base Case 2004 also includes coal quality assumptions which differentiate coal by rank (i.e., bituminous, sub-bituminous, and lignite) and sulphur content. Section 7.1.2 below describes the coal quality assumptions in the Canadian IPM Base Case 2004.

7.1.1 Coal Markets

Canadian provinces who import their coal acquire it from either the U.S. or from other Canadian provinces. With the exception of two plants, which use Saskatchewan lignite, Ontario consumes significant amount of U.S. coal. In the U.S. implementation of IPM, coal markets are modeled using 40 coal supply regions and 39 coal demand regions. Figure 7.1 below shows a map of the coal supply regions.

Figure 7.1. Map of the Coal Supply Regions in the Canadian IPM Base Case 2004



Each of the coal power plants is assigned to a coal demand region. A coal demand region is connected to a subset of the coal supply regions and can get coal at a certain transportation charge. For the provinces of Ontario, Nova Scotia and Manitoba, which import U.S. coal, plants were assigned to new coal demand regions representing the provinces of Ontario, Nova Scotia and Manitoba. These coal demand regions are linked to U.S. Central Appalachia, Northern Appalachia, and Western Northern Great Plains coal supply regions. The cost of transporting the coal is assumed to be similar to what it currently costs to transport it to the northernmost U.S. coal demand regions. The non-mine mouth coal plants are provided with multiple low and high sulphur choices in order to allow them to comply with environmental regulations at least cost. The sulphur content of coal is plant specific. Table 7.2 presents the year 1999 coal prices.

Table 7.2. Provincial Level Delivered Price Projections for Canadian Coal (1999CDN$/MMBtu)

Province	Coal Grade	1999$CDN/MMBtu	Annual Productivity Improvement (%)
New Brunswick	Bituminous	2.61	1.1%
Ontario	Lignite	1.50	0.7%
Saskatchewan	Lignite	0.89	0.7%
Alberta	Sub-bituminous	0.61	0.7%
	Bituminous	0.45	0.7%

Sources: Statistics Canada Report 57-202 "Electric Power Generation Transmission and Distributions", Table 6 (year 2000), and Energy Information Administration, Annual Energy Outlook, 2003. Note: Values were converted from 2000 to 1999 dollars using a 2000 CPI of 113.5 and a 1999 CPI of 110.5.

7.1.2 Coal Grade Assignment

In the U.S. model, coal grades are assigned based on the maximum regulated SO_2 emission rate. Each unit is then given a selection of coals with sulphur contents all below this maximum rate. The model chooses which coal each unit will use based on economic and other considerations and, therefore, may have an emission rate lower than the regulated level.

Any unit choosing to install control technology such as a scrubber will automatically be allowed to burn any coal, including those with sulphur contents higher than the upper bound because the technology will reduce the emissions to an acceptable level. This captures the effect of lower prices for higher sulphur coal in general.

In the Canadian IPM Base Case 2004, it was assumed that any unit using mine-mouth coal will not switch coal even if emission reduction technology is installed. For units not using mine-mouth coal, similar methodology is followed for choosing coal as in the U.S. implementation.

In the Canadian IPM Base Case 2004, the current reported emission rates are used as the upper bound for these units with access to a choice of coals. The coal units are then allowed the choice of several imported coals at sulphur contents equal to or less than this upper bound. The IPM then chooses the most economic coal for the unit going forward with the emission rates of the units possibly changing depending on the coal choices.

7.2 Natural Gas

Natural gas is an important input in the Canadian IPM Base Case 2004. There are numerous methods of calculating the natural gas prices, including using supply curves as in the U.S. implementation. The Canadian IPM Base Case 2004 does not use this method, but instead used natural gas prices based on the EIA gas price projection. Because the EIA does not provide gas prices in Canada, the latest EIA forecast (AEO 2003) of natural gas price was used to determine the price at the Henry Hub. Regional Canadian prices were derived by utilizing seasonal transportation adders for each region off of Henry Hub[11]. Adders were kept constant over the study horizon and were calculated based on historical gas price data. Table 7.4 below summarizes the results of this derivation. Natural gas generation was not allowed in Newfoundland, Labrador and Prince Edward Island.

[11] The Henry Hub is a gas pipeline junction in Louisiana, which interconnects with nine interstate and four intrastate pipelines and offers shippers access to pipelines that have markets in the U.S. Gulf Coast, Southeast, Midwest, and Northeast regions. Due to the Hub's strategic centralized location, the price of natural gas at the Henry Hub serves as the generally accepted reference point for U.S. natural gas trading.

7.2.1 Seasonal Gas Adders

Delivered natural gas prices for the Canadian provinces were developed by performing statistical calculations on historic prices for key liquid pricing points. In this effort, historical daily gas prices as reported by the publication "Gas Daily" were used. Daily data for over 8 years were used for Sumas and AECO prices. Dawn is a relatively new hub and has been in operation for the last five years. Therefore, for Dawn, data for the last five years were used in determining the seasonal adders. The representative point used for each of the Canadian regions is shown in Table 7.3 below. In deciding the representation point within a region, consideration was given to the locale, which was highly liquid. For example, for British Columbia, the pricing point "Sumas" was considered a representative pricing point even though another pricing point "Westcoast Station 2" was available. Both winter and summer differentials were calculated for each of the regions as shown in the table. Historic data points, which were outside the range of two standard deviations of the seasonal average, were considered outliers representing short spikes due to weather, operational constraints, and short-term market fluctuations.

Table 7.3. Gas Supply Adders for Canadian Regions

Region	**Representative Point**	**Other Adders**	**Final Price Adder (1999 CDN cents/MMBtu)**	
			Winter	Summer
Maritimes	Maritimes and Northeast Pipeline	None	-150.4	-169.0
Quebec	AECO + Local Pipeline	TransCanada Pipeline	43.4	37.2
Ontario	DAWN	None	21.7	9.0
Manitoba	AECO + Local Pipeline	TransCanada Pipeline	-51.2	-57.4
Saskatchewan	AECO + Local Pipeline	TransGas	-94.6	-100.8
Alberta	AECO	None	-109.6	-116.4
British Columbia	Sumas	None	-67.6	-102.61

Sources: "Gas Daily", Platts and "Canadian Natural Gas Focus", GLC Energy Publications Inc.
Note: Maritimes includes Nova Scotia and New Brunswick. It does not include Newfoundland and Labrador and Prince Edward Island as none of these receive gas.

7.2.2 Emission Factors

Since natural gas does not contain any sulphur, the Canadian IPM Base Case 2004 does not include emission factor assumptions for SO_2 in natural gas.

7.3 Fuel Oil

Oil steam boilers in Canada usually fire residual fuel oil. There is also a limited amount of diesel-fired generation capacity in Canada. The supply assumptions, including price projections, and characteristics of these fuels are covered in Sections 7.3.1 and 7.3.2 respectively.

7.3.1 Supply Assumptions

Unlike imported coal from the U.S., which is derived endogenously in the Canadian IPM Base Case 2004, fuel oil prices are stipulated exogenously. The residual fuel oil price assumptions used in the Canadian IPM Base Case 2004 are summarized in Table 7.4. There are three types of fuel oil: light fuel oil (LFO), heavy fuel oil (HFO), and diesel. Values for all three types are reported.

Table 7.4 Fuel Oil and Diesel Price Summary (1999 CDN $)

($/MM Btu)	NF	NL	PE	NS	NB	QC	ON	MB	SK	AB	BC
LFO	11.29	11.12	N/A	9.12	6.50	6.40	9.18	9.36	N/A	N/A	N/A
HFO	4.70	4.70	5.32	4.73	3.88	3.60	5.47	N/A	3.87	N/A	N/A
Diesel	7.51	7.51	8.43	7.68	8.15	13.80	7.78	18.87	9.58	12.23	12.00

Source: Statistics Canada Report 57-202 "Electric Power Generation Transmission and Distribution", Table 6 (year 2000).
Note: Labrador receives NF fuel oil. Also, all values were converted from 2000 to 1999 dollars using a 2000 CPI of 113.5 and a 1999 CPI of 110.5.

7.3.2 Emission Factors

The emission factors for fuel oil describe the SO_2 content per unit energy in the fuel oil. In the Canadian IPM Base Case 2004, these factors represent the emissions that would occur if the fuel oil were combusted and no abatement occurred at the facility. The sulphur content of fuel oil is plant specific while diesel contains 0.3 lbs/MMBtu SO_2.

7.4 ORIMULSION®

ORIMULSION® is a liquid fossil fuel made up of 70% bitumen and 30% water. Bitumen is a naturally occurring hydrocarbon from the Orinoco Belt in Eastern Venezuela. In Canada, it is used New Brunswick. Section 7.4.1 deals with the price of ORIMULSION® in the Canadian IPM Base Case 2004 while emission factors are covered in Section 7.4.2.

7.4.1 Price Projections

While the actual price of ORIMULSION® is not publicly available, it is usually available in 20 year fixed contract agreements that are negotiated on a case by case basis in order to keep them price competitive with coal and oil-fired power plants. For the purposes of the Canadian IPM Base Case 2004, the price of ORIMULSION® in New Brunswick was assumed to be maintained at the province's coal price projection.

7.4.2 Emission Factors

The Canadian IPM Base Case 2004 includes emission factors for SO_2 of ORIMULSION®. ORIMULSION® contains 4.4 lbs/MMBtu of SO_2.

7.5 Biomass

Biomass is offered as a fuel for existing dedicated biomass plants and potential biomass gasification combined cycle plants under the Canadian IPM Base Case 2004. In addition to these plants, it is also offered to all coal-fired power plants under policy cases that include the biomass co-firing options described above in Section 5.4.2. In the U.S. implementation, biomass fuel supply curves were developed and used, but not so in the Canadian IPM Base Case 2004. The market structure for biomass in the Canadian IPM Base Case 2004 is covered in Section 7.5.1 while Section 7.5.2 deals with emission factors for this fuel type.

7.5.1 Market Structure

Biomass prices in the Canadian IPM Base Case 2004 are derived based on the year 1999 actual prices and maintained constant during the study period. Biomass is hence treated differently in this implementation. The reason for this is that no one source summarized an internally consistent set of biomass prices across multiple provinces. Table 7.5 below outlines the delivered biomass price projections in the Canadian IPM Base Case 2004.

Table 7.5. Delivered Biomass Price Projections – Average 1999 CDN $/MMBtu

Province	Biomass Grade	2005 – 2020
Nova Scotia	Wood	0.92
Quebec	Wood	0.38
Ontario	Wood	0.55
Alberta	Wood	0.74
British Columbia	Wood	0.59
All Other Provinces	Wood	0.64

Source: Statistics Canada. Electric Power Generation, Transmission and Distribution, 1999. Pub # 57-202, Table 6.

7.5.2 Emission Factors

The Canadian IPM Base Case 2004 models SO_2 emissions from biomass combustion using biomass emission factors. Biomass contains 0.08 lbs/MMBtu of SO_2.

7.6 Nuclear Fuel

Canada has approximately 10 GW of nuclear power plant capacity. Nuclear plants in general have low variable costs and hence are dispatched up to their availability. The Canadian IPM Base Case 2004 nuclear fuel price projections are consistent with those of the U.S. implementation and are shown below in Table 7.6. They are based on the U.S. EIA's Annual Energy Outlook 2003.

Table 7.6. Nuclear Fuel Price Projections

Year	Nuclear Fuel Price (1999 CDN cents/MMBtu)
2005	0.63
2010	0.64
2015	0.63
2020	0.63
2025	0.63
Average	0.63

Chapter 8: Canadian IPM Base Case 2004 Results

Previous chapters of this report have focused on the methodological underpinnings of IPM (Chapter 2) and the assumptions underlying the Canadian IPM Base Case 2004 (Chapters 3-7). The current chapter is devoted to a discussion of the key results forecasted under the base case. Before turning to these results, there is a short summary of the base case scenario specifications.

8.1 Scenario Specifications

The Canadian IPM Base Case 2004 takes into account those Federal and Provincial laws and regulations (refer to Table 3.9 in Chapter 3 for a complete list of these laws and regulations), which affect air emissions from the electric power sector in Canada's 10 provinces, treating Newfoundland and Labrador as separate model regions. Through unit specific baseline emission rates for existing and planned/committed units, the Canadian IPM Base Case 2004 also incorporates province-specific regulations for SO_2 and NO_x for all provinces.

Section 3.9 fully describes the specifics of the existing air regulations modeled in the Canadian IPM Base Case 2004 to represent the SO_2 and NO_x air regulatory programs.

8.2 Summary of Results

This section summarizes the results of the Canadian IPM Base Case 2004..

8.2.1 Electric Power Generation by Fuel Type

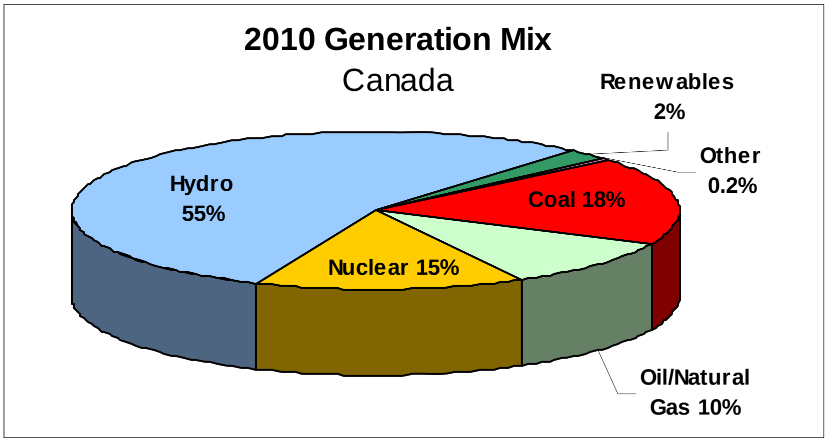
Under the Canadian IPM Base Case 2004 total electric generation is projected to grow 8.4% between 2010 and 2020 (from 652 TWh in 2007 to 707 TWh in 2020). Over the entire 2010-2020 modelling period the largest share of generation is from hydro (representing 54.9% of total generation in 2010 and 53.6% in 2020), followed by coal (representing 17.9% in 2010 and 16.5% in 2020). This is summarized in Table 8.1 and illustrated in Figure 8.1.

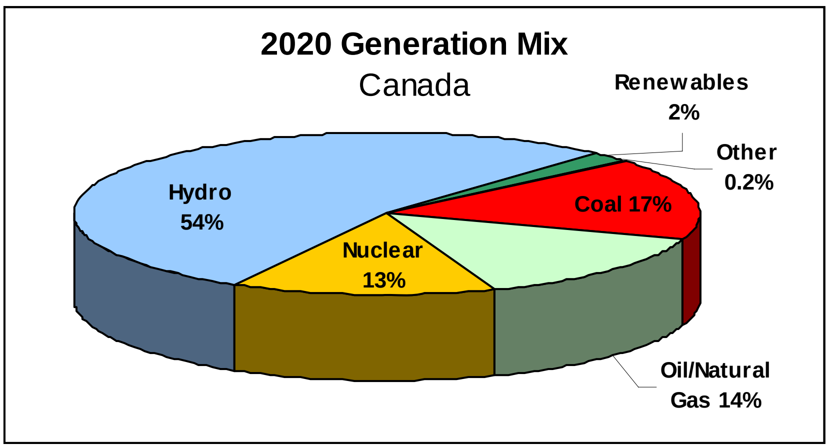
Table 8.1. Electric Generation by Run Year under the Canadian IPM Base Case 2004

	2010		2015		2020	
Fuel Type	**TWh**	**% Share**	**TWh**	**% Share**	**TWh**	**% Share**
Coal	116.84	17.9%	116.84	17.1%	116.84	16.5%
Oil/Natural Gas	65.73	10.1%	88.80	13.0%	99.73	14.1%
Nuclear	94.92	14.6%	94.92	13.9%	94.92	13.4%
Hydro	357.65	54.9%	367.40	53.7%	379.18	53.6%
Renewables	15.33	2.4%	15.33	2.2%	15.33	2.2%
Other	1.20	0.2%	1.20	0.2%	1.20	0.2%
Total	**651.66**	**100%**	**684.48**	**100%**	**707.20**	**100%**

Notes:
1. "Other" includes electricity generated by plants not falling in the previously listed categories.

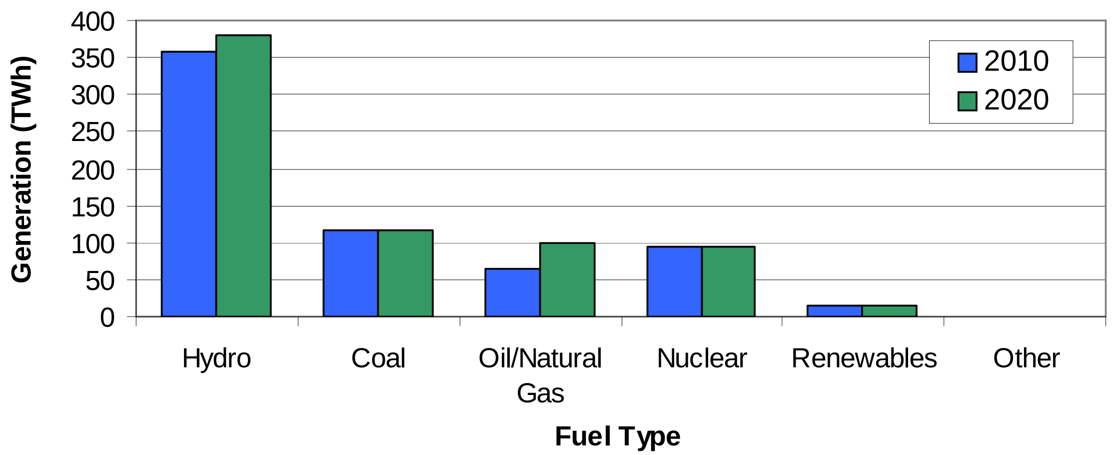
Figure 8.1. Generation Mix in 2010 and 2020 under the Canadian IPM Base Case 2004





Between 2010 and 2020, generation from natural gas/oil experiences a growth of 51.5% (from 66 TWh in 2010 to 100 TWh in 2020) compared to coal units that experience no change in generation (117 TWh in 2010 & 2020), and no change in generation from nuclear sources (95 TWh in 2010 & 2020). Figure 8.2 provides side-by-side comparisons of the 2010 and 2020 generation levels for each fuel type.

Figure 8.2. Comparison of Projected Electricity Generation by Fuel Type in the Canadian IPM Base Case 2004

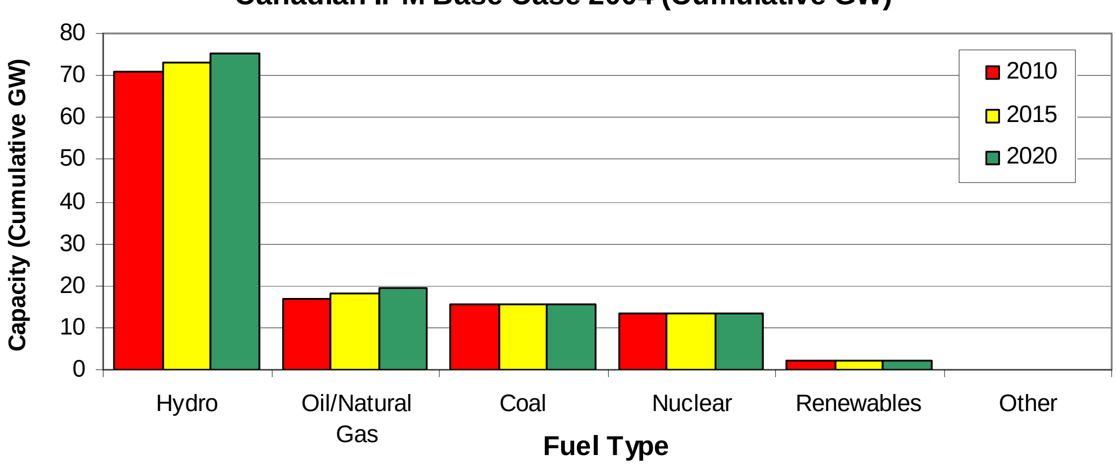


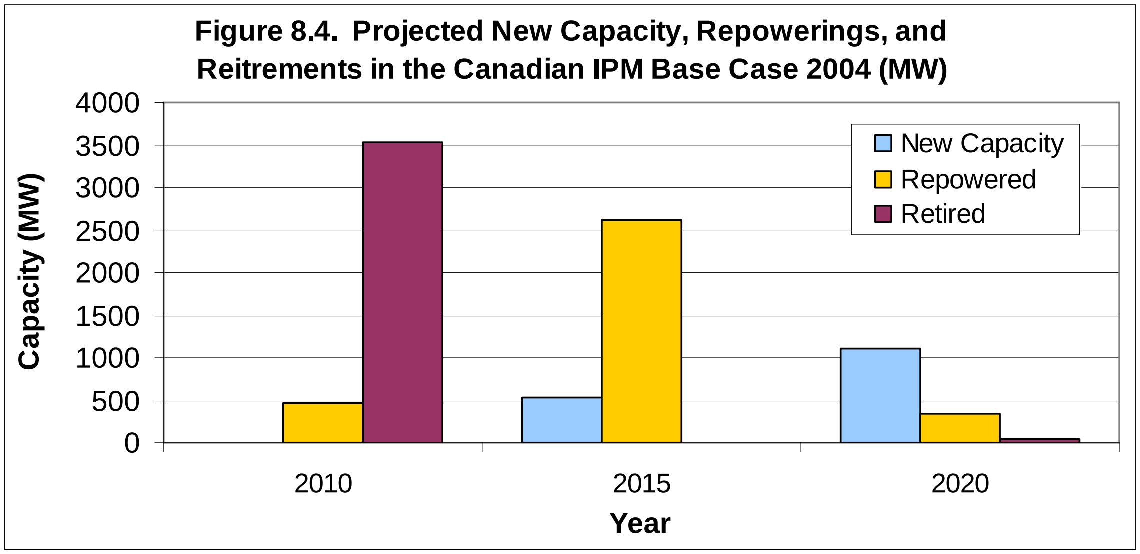
8.2.2 Capacity Changes

Overall Trends: Under the Canadian IPM Base Case 2004 electric generation capacity is projected to grow 5.8% between 2010 and 2020 (from 120 GW to 127 GW). As seen in Figure 8.3, capacity growth occurs solely among hydro and oil/natural gas plants. Hydro increases capacity 5.9% (from 71 GW to 75 GW) where oil/natural gas plants increase their capacity 16.2% (from 17 GW to 20 GW). As discussed in the next paragraph, the boost in oil/natural gas capacity is from repowered and new combined cycle units. The capacity for all other fuels is projected to remain unchanged over the 2010-2020 period.

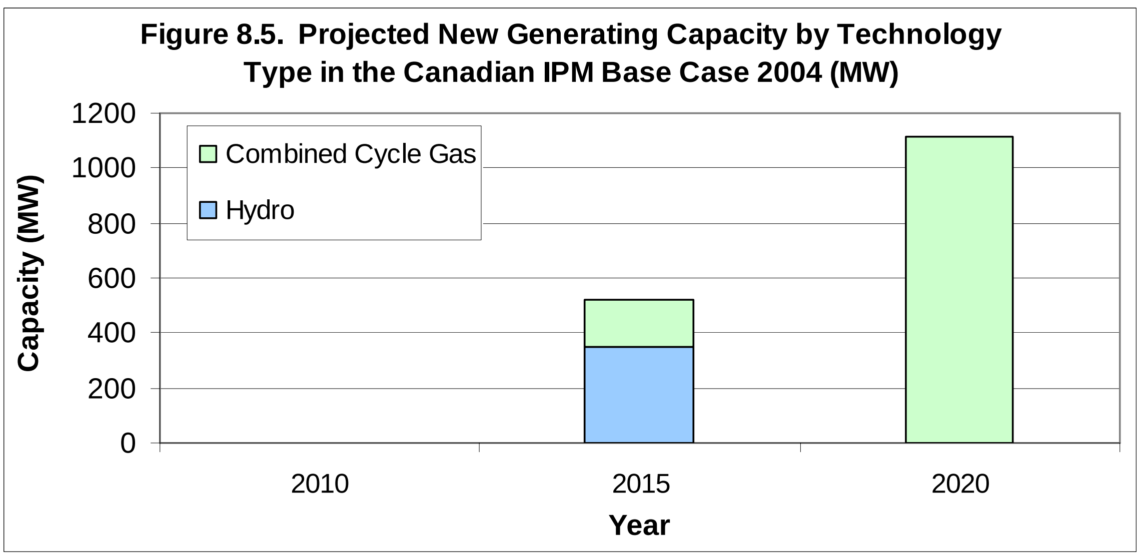
During the 2010-2020 modelling period, 1.6 GW of new capacity is projected to be added and 3.4 GW of oil/gas steam units are projected to be repowered to combined cycle gas. During this period, 1.2 GW of capacity from coal-fired units is projected to be retired, 1.7 GW of capacity from oil/gas steam units are projected to be retired and 0.7 GW of capacity from combustion turbine units are projected to be retired. No nuclear capacity is projected to be retired. These changes are shown in Figure 8.4. As seen in Figure 8.5, 79% (1.3 GW) of the new capacity added between 2010 and 2020 is from combined cycle gas units, including cogeneration units, and 21% (0.3 GW) is from hydro.

Figure 8.3. Comparison of Projected Capacity by Fuel Type in the Canadian IPM Base Case 2004 (Cumulative GW)





Note that projected retirements shown in 2010 occur in the 2007 model run year.



Emission Control Strategies and Retrofit Patterns: There are basically four ways that the electric system can meet emission limits: (1) shifting generation to less polluting units among the existing stock, (2) fuel switching (e.g., shifting generation from high to low sulphur coal), (3) changing the capacity mix (through capacity additions, repowerings, and retirements) from one type of fuel to another, from less to more efficient units, and from units with limited or no emission controls to new units with more extensive or state-of-the-art controls, and (4) installing emission controls on existing plants. Capacity trends can shed light on the third and fourth of these options. The previous discussion in this section touched upon the third option (i.e., capacity additions, repowering, and retirements). The remainder of this section examines capacity trends that provide insights in the fourth option by revealing the retrofit patterns in the Canadian IPM Base Case 2004.

As described in detail in Chapter 5, the Canadian IPM Base Case 2004 provides a range of post-combustion emission control technologies to existing units: two types of scrubbers to reduce sulphur dioxide (SO_2) emissions and two retrofit options – selective catalytic reduction (SCR) and selective non-catalytic reduction (SNCR) – to reduce nitrogen oxides (NO_x). Figure 8.6 shows capacity trends for coal and oil/gas steam plants differentiated according to the absence, presence and type of emission control technology. The capacity depicted in Figure 8.6 includes both pre-existing and newly installed environmental retrofits that are projected to be in place on existing coal and oil/gas steam plants in each model run year. Figure 8.6 shows a small increase in the installation of emission control technologies on coal units. By 2020 34.9% of the coal capacity is projected to include some form of NO_x or SO_2 emission control technology, compared to 33.4% in 2010. Over the modelling period, oil/gas steam capacity both with and without NOx controls decreases due to this capacity repowering.

Figure 8.6. Capacity with SO2 or Post-Combustion NOx Controls in the Canadian IPM Base Case 2004 (Cumulative MW)

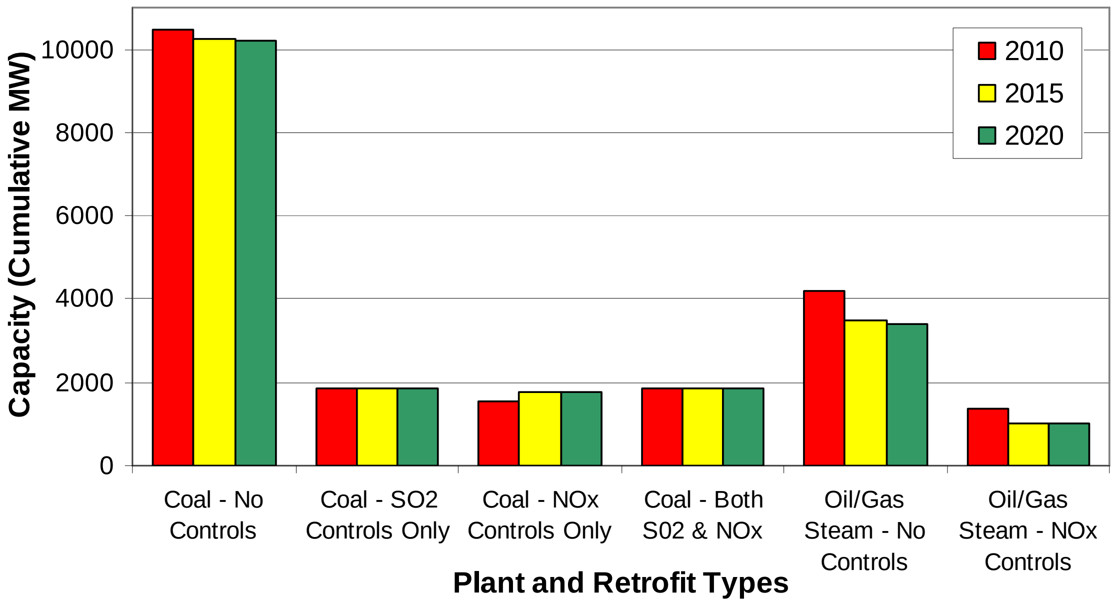
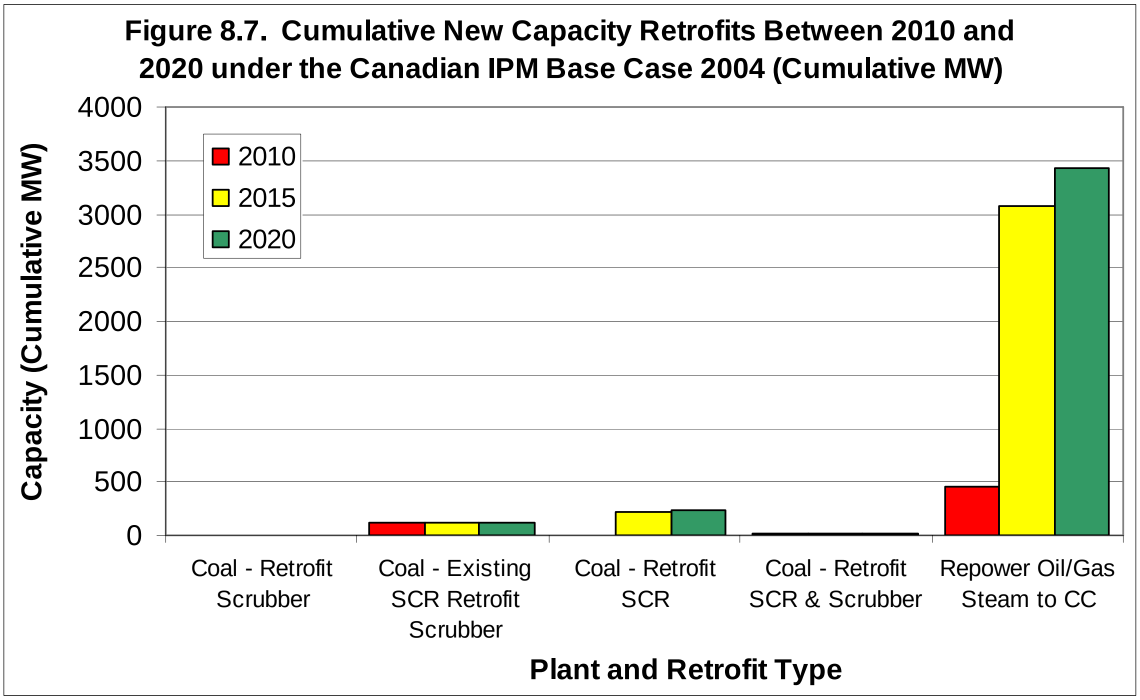


Figure 8.7 focuses exclusively on the capacity that is projected to install environmental retrofits over the course of the modelling period. For each model run year, this figure shows the cumulative capacity of existing coal and oil/gas steam plants that are projected to have installed new NO_x or SO_2 controls in response to the environmental air regulation included under the Canadian IPM Base Case 2004 (as described in Section 3.9). Repowering of oil/gas steam units is also included in the figure, because for some units, repowering is a compliance strategy. Based on cost, the model has chosen to repower oil/gas steam units to combined cycle units, even though three repowering options exist (coal to combined cycle, coal to integrated gasification combined cycle, and oil/gas steam to combined cycle).



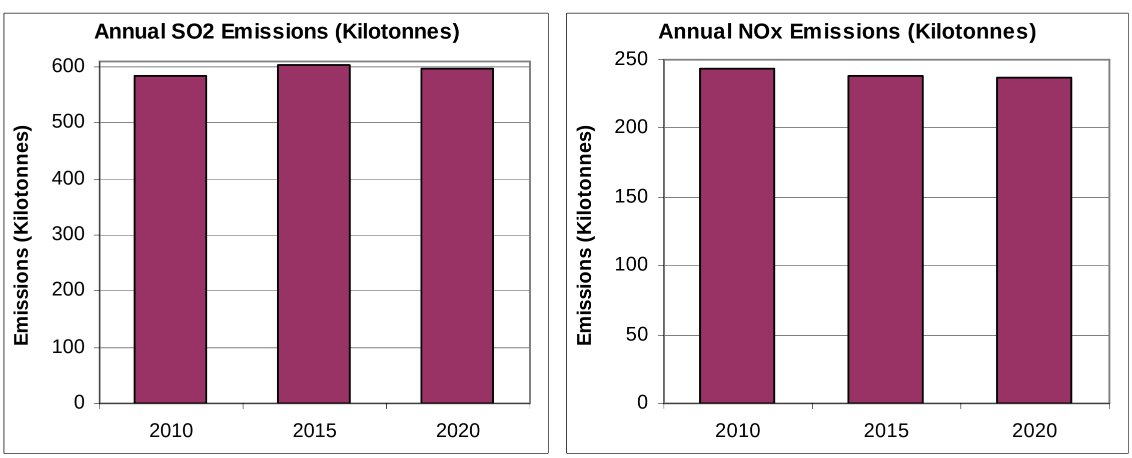
8.2.3 Air Emissions

In the Canadian IPM Base Case 2004, SO_2 emissions increase through 2020, while NOx emissions decrease slightly over that same time period. Table 8.3 and Figure 8.8 below provide summaries of the national emission for SO_2 and NO_x in the Canadian IPM Base Case 2004 for 2010, 2015, and 2020.

Table 8.3. National Emission Levels in the Canadian IPM Base Case 2004

Pollutant	2010	2015	2020
SO_2 (Kilotonnes)	583.07	602.72	598.63
NO_x (Kilotonnes)	243.65	238.83	237.58

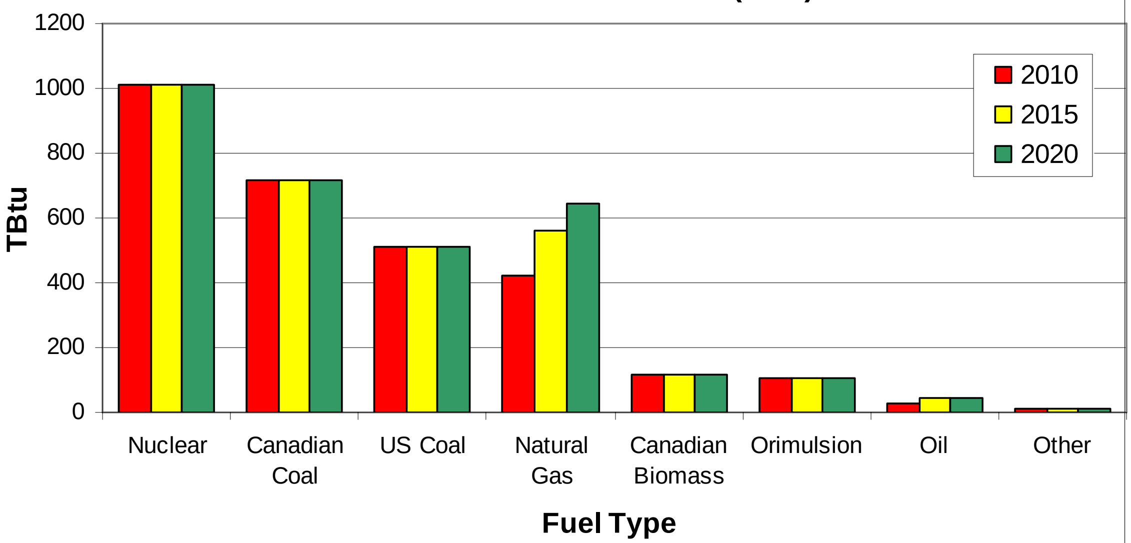
Figure 8.8. The Canadian IPM Base Case 2004 Forecast of Annual Emissions from Electric Power Generation in Canada



8.2.4 Fuel Usage

Figure 8.9 shows the annual fuel consumption by major fuel type categories on a TBtu (Trillion British thermal units) basis projected under the Canadian IPM Base Case 2004. Several observations can be made. First, Canadian and imported coal account for 1226.7 TBtu or 42% percent of the 2919.3 TBtu consumed for electricity generation in 2010. By 2020, total coal consumption is projected to account for 1226.7 TBtu or 38.9% of the 3152.4 TBtu used for electricity generation. Second, the consumption of natural gas for electric generation increases steadily over time due to increased electricity demand. Specifically, natural gas TBtu usage increases by 52% between 2010 and 2020. Third, nuclear fuel usage remains constant from 2010 through 2020 (1009.2 TBtu). The consumption of Canadian biomass (116 TBtu) and orimulsion (107 TBtu) also remains steady during this time period. Fourth, oil consumption for electric generation was 29.3 TBtu in 2010 and 42.3 TBtu in 2020. Fifth, the fuel type category "Other" in Figure 8.9 includes biomass, waste fuels, and landfill gas.

Figure 8.9. Fuel Usage (2010-2020) Under the Canadian IPM Base Case 2004 (Tbtu)



Note: Other (Landfill gas, etc.) consumption is 12.2 Tbtu annually from 2010 through 2020.

8.2.5 Prices

Firm Wholesale Electricity Prices

The Canadian IPM Base Case 2004 includes national and regional projections of wholesale firm electricity prices for 2010 – 2020. The wholesale realized electricity price in the Canadian IPM Base Case 2004 is defined as the sum of energy and capacity prices. Since the Canadian IPM Base Case 2004 assumed a fully operating competitive wholesale market for energy and capacity, the wholesale firm electricity price only includes production costs, but not previously incurred generating facility embedded costs, which typically would be included in modelling cost-of-service pricing in a regulated electricity market.

Figure 8.10 displays the national average wholesale firm electricity price at the generator that results under the Canadian IPM Base Case 2004. An increase of 6.6 mills/kWh is forecast between 2010 and 2015, followed by a 4.1 mills/kWh increase through 2020. Average firm wholesale electricity prices for IPM regions are shown in Table 8.4. They vary from a 2010 low of 19.2 mills /kWh in Manitoba to highs of 42.7 mills/kWh and 40.0 mills/kWh in Ontario and Quebec. The differential between the highest and the lowest regional prices is projected to decline from 13.1 mills/kWh in 2010 to 9.3 mills/kWh in 2020.

Figure 8.10 National Wholesale Electricity Price in the Canadian IPM Base Case 2004 (US mills/KWh)

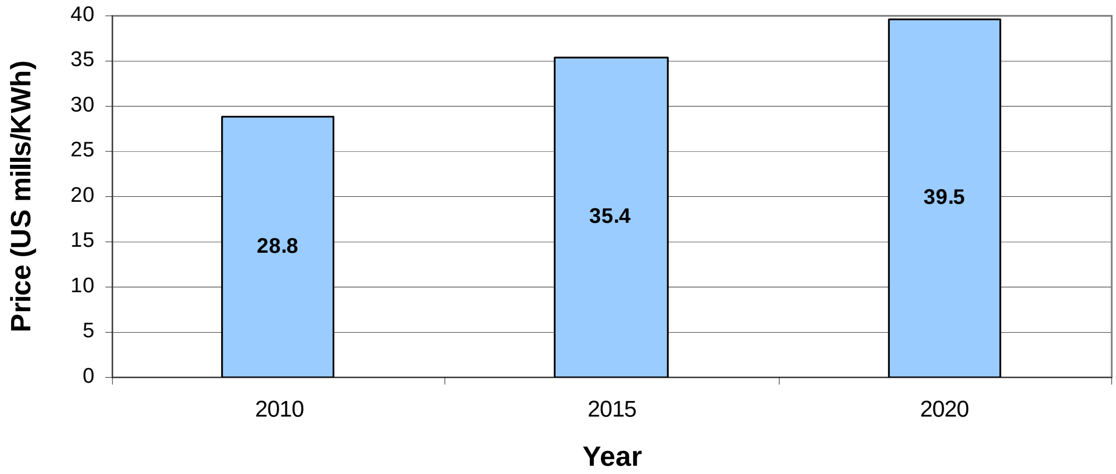
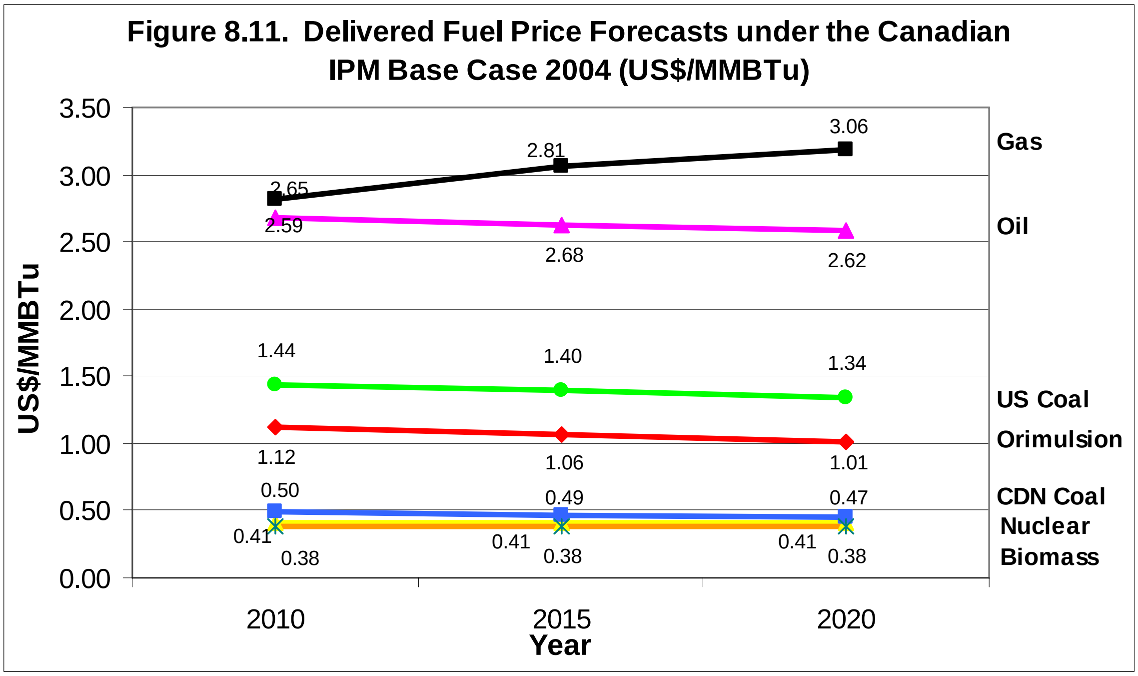


Table 8.4. Wholesale Electricity Prices (mills/kWh) by IPM Model Region

Province	Wholesale Cost of Electricity (US mills/KWh)		
	2010	**2015**	**2020**
Newfoundland	31.97	44.79	36.25
Labrador	28.12	35.95	39.81
Prince Edward Island	30.29	37.22	39.43
Nova Scotia	27.51	31.79	33.42
New Brunswick	26.48	32.37	34.04
Quebec	30.18	36.92	40.04
Ontario	27.65	36.86	42.69
Manitoba	19.19	25.71	35.54
Saskatchewan	23.37	28.97	36.73
Alberta	28.97	32.82	35.42
British Columbia	32.27	34.74	37.77
Canada	**28.80**	**35.41**	**39.53**

Allowance Prices
IPM is capable of projecting allowance prices for pollutants regulated under cap-and-trade programs. This is not applicable in the Canadian IPM Base Case 2004 but will be applicable to future policy cases having cap-and-trade programs.

Fuel Prices
The Canadian IPM Base Case 2004 also includes projections of coal, gas, biomass, oil, orimulsion and nuclear fuel prices for 2007-2020. Only U.S. coal prices are endogenously determined in the Canadian IPM Base Case 2004 and reflect the supply curve assumptions and resulting demand in the Canadian IPM Base Case 2004. Figure 8.11 below provides a summary of the delivered fuel prices in the Canadian IPM Base Case 2004. Prices of other fuels are not determined endogenously, but, as described in Chapter 7, they are stipulated exogenously.



8.3 Detailed Outputs

This section provides detailed model results for the Canadian IPM Base Case 2004. Among other information, this section includes a system level summary of results (Table 8.5) and national-level projections of electric capacity, generation and capacity factors by key plant types and emission control technologies (Tables 8.7 – 8.10). Disaggregated breakdowns by regions and technologies are included for 2010 (Tables 8.11 and 8.12), 2015 (Tables 8.13 and 8.14), and 2020 (Tables 8.17 and 8.18). These breakdowns cover electric generation, fuel usage, and emissions for NO_x and SO_2 by model region and plant type in the Canadian IPM Base Case 2004. Table 8.6 provides a key to the abbreviation used to identify model plants in Tables 8.7-8.10.

Table 8.5. The Canadian IPM Base Case 2004 – System Summary

	2010	**2015**	**2020**
1. Reserve Margin Capacity [MW]	101632	104502	107522
Plus Firm Purchases [MW]	0	0	0
Plus Transmission In [MW]	4605	6856	9907
Total Reserve Margin Capacity [MW]	106236	111358	117429
2. Peak Load [MW]	87776	93551	98517
Less DSM [MW]	0	0	0
Plus Firm Sales [MW]	0	0	0
Plus Transmission Out [MW]	2790	3645	4008
Net Demand [MW]	90566	97197	102524
3. Reserve Margin [%]	17	15	15
4. Generation [GWh]	651663	684480	707200
Inter-Region Transmission {GWh]	-15124	-4594	9052
Pumping & Storage Losses [GWh]	0	0	0
Plus Purchases [GWh]	0	0	0
Less Sales [GWh]	0	0	0
5. Total Supply for Demand [GWh]	636539	679886	716252
6. Projected Demand [GWh]	636539	679886	716252
Energy Not Served [GWh]	0	0	0
Less DSM [GWh]	0	0	0
Net Demand [GWh]	636539	679886	716252
7. Dumped Energy [GWh]	0	0	0
Capacity Avoided Costs [US$/kW/a]			

Notes
1. "Reserve Margin Capacity [MW]" is the amount of power plant capacity available to satisfy the power system's reserve margin requirements.
2. "Transmission In [MW]" is the total capacity imported by regions in the system.
3. "Transmission Out [MW]" is the total capacity exported by regions in the system.
4. "Reserve Margin [%]" is the percentage of capacity reserved over and above peak load to maintain the reliability of the power system. Reserve Margin (%) = [Total Reserve Margin Capacity (in No.1) minus Net Demand (in No.2)] divided by Net Demand (in No.2).
5. "Inter-Regional Transmission [GWh]" is the energy lost during the process of transmitting power over high-voltage lines between regions.
6. "Pumping and Storage Losses [GWh]" is the energy lost to pump and store water in pump storage plants.
7. "Total Supply for Demand [GWh]" is the amount of electricity available to meet electricity demand.
8. "Capacity Avoided Cost [US$/kW/a]" is the shadow price associated with the reserve margin constraint. It is the price attributable to the electricity system's reliability requirements.
9. "Firm Purchases [MW]," "Peak Load [MW]," "DSM (demand side management) [MW]," "Firm Sales [MW]," and "Projected Demand [GWh]" are inputs to the model. The remaining terms shown in Table 8.5 are model outputs.

Table 8.6. Key to Plant Type Abbreviations Used in the Canadian IPM Base Case 2004

Scrubbed Coal_NOx	1	Existing coal plant with both a scrubber and post-combustion NOx controls
Scrubbed Coal	2	Existing coal plant with a scrubber but without post-combustion NOx controls
Unscrubbed Coal_NOx	3	Existing coal plant without a scrubber but with post-combustion NOx controls
Unscrubbed Coal	4	Existing coal plant without a scrubber and without post-combustion NOx controls
Oil/Gas Steam	5	Oil/Gas Steam plant without post-combustion NOx controls
Oil/Gas Steam_Nox	6	Oil/Gas Steam plant with post-combustion NOx controls
Nuclear	7	Nuclear
Hydro	8	Hydro
Comb.Cycle Gas	9	Comb.Cycle Gas (CC)
IGCC	10	Integrated coal gasification combined cycle
Turbine	11	Combustion Turbine (CT)
Biomass	12	Biomass Gasification Combined Cycle
Landfill Gas	13	Landfill Gas
Wind	14	Wind
Non Fossil_Other	15	Refuse, Bagasse, Municipal Solid Waste, Paper Pellets, Sludge Waste, Tires, Waste Heat, Liquid Acetonitrile Waste, Batteries
Fossil_Other	16	Waste Coal, Petroleum Coke, Digester Gas, Waste Oil
Cgn_Gas	17	Gas burning cogenerators
Cgn_Oil	18	Oil burning cogenerators
Rep.Coal-CC	19	Coal plant repowered to combined cycle gas
Rep.O/G-CC	20	Oil/Gas steam plant repowered to combined cycle gas
Rep.Coal-IGCC	21	Coal plant repowered to IGCC
Ret.Scrubber	22	Coal plant retrofitted with a Scrubber *only*
Ret.ExistSCR & Scrub	23	Coal plant with an existing SCR retrofit with a scrubber
Ret.SCR	24	Coal plant retrofitted with an SCR *only*
Ret.ExistScrub & SCR	25	Coal plant with an existing scrubber retrofit with SCR
Ret.SNCR	26	Coal plant retrofitted with an SNCR *only*
Ret.ExistScrub & SNCR	27	Coal plant with an existing scrubber retrofit with SNCR
Ret.SCR+Scrb	28	Coal plant retrofitted with both an SCR & a Scrubber
Ret.SNCR+Scrub	29	Coal plant retrofitted with both an SNCR & a Scrubber
Ret.O/G SCR	30	O&G plant retrofitted with an SCR *only*
Ret.O/G SNCR	31	O&G plant retrofitted with an SNCR *only*
CT Early Retirement	32	Combustion Turbine Early Retirement
CC Early Retirement	33	Combined Cycle Gas Early Retirement
O/G Early Retirement	34	Oil/Gas Steam Early Retirement
Coal Early Retirement	35	Coal Early Retirement
Nuke Early Retirement	36	Nuclear Early Retirement

Notes

1. The “early retirement” model plants types (types 32-36) indicate the capacity that is endogenously retired by the model, because they are not economical to remain operating. Such plants do not carry any costs, whereas a plant not dispatched (but not retired) would incur fixed operations and maintenance (FOM) costs.
2. The “Exist” designation (e.g., ExistSCR) implies that the indicated technology was present at start-up of the model. That is, the technology was on an existing plant. The “Exist” designation is not used to identify a technology installed by the model even when a second retrofit is installed in a subsequent model run year. For example, a plant that has SCR at start-up of the model and is subsequently retrofit by the model with a scrubber would be represented by model plant type 23 (Ret.ExistSCR & Scrub). On the other hand, a plant that was retrofit by the model with SCR in 2007 and with a scrubber in 2010 would be represented by model plant type 28 (Ret.SCR+Scrb.).

Table 8.7. Capacity (MW) by Plant Type in the Canadian IPM Base Case 2004

Plant Type	2010	2015	2020
Scrubbed Coal_Nox	980	980	980
Scrubbed Coal	908	908	908
Unscrubbed Coal_Nox	683	683	683
Unscrubbed Coal	10,450	10,234	10,216
Oil/Gas Steam	4,175	3,480	3,411
Oil/Gas Steam_Nox	1,359	1,005	1,005
Nuclear	13,593	13,593	13,593
Hydro	71,130	72,977	75,347
Comb.Cycle Gas	1,623	1,798	2,913
IGCC	0	0	0
Turbine	2,525	2,525	2,525
Biomass	1,741	1,741	1,741
Landfill Gas	13	13	13
Wind	511	511	511
Non Fossil_Other	127	127	127
Fossil_Other	25	25	25
Cgn_Gas	5,999	5,999	5,999
Cgn_Oil	724	462	308
Rep.Coal-CC	0	0	0
Rep.O/G-CC	459	3,081	3,431
Rep.Coal-IGCC	0	0	0
Ret.Scrubber	950	950	950
Ret.ExistSCR & Scrub	290	290	290
Ret.SCR	851	1,067	1,085
Ret.ExistScrub & SCR	0	0	0
Ret.SNCR	0	0	0
Ret.ExistScrub & SNCR	0	0	0
Ret.SCR+Scrb	579	579	579
Ret.SNCR+Scrub	0	0	0
Ret.O/G SCR	0	0	0
Ret.O/G SNCR	0	0	0
CT Early Retirement	716	716	716
CC Early Retirement	33	33	33
O/G Early Retirement	1,631	1,631	1,679
Coal Early Retirement	1,150	1,150	1,150
Nuke Early Retirement	0	0	0
Total	**123,224**	**126,556**	**130,217**

Table 8.8. Capacity Addition and Changes (MW) by Plant Type in the Canadian IPM Base Case 2004

Plant Type	2010	2015	2020
Scrubbed Coal_Nox	0	0	0
Scrubbed Coal	0	0	0
Unscrubbed Coal_Nox	0	0	0
Unscrubbed Coal	0	0	0
Oil/Gas Steam	0	0	0
Oil/Gas Steam_Nox	0	0	0
Nuclear	0	0	0
Hydro	0	347	0
Comb.Cycle Gas	0	175	1115
IGCC	0	0	0
Turbine	0	0	0
Biomass	0	0	0
Landfill Gas	0	0	0
Wind	0	0	0
Non Fossil_Other	0	0	0
Fossil_Other	0	0	0
Cgn_Gas	0	0	0
Cgn_Oil	0	0	0
Rep.Coal-CC	0	0	0
Rep.O/G-CC	459	2622	350
Rep.Coal-IGCC	0	0	0
Ret.Scrubber	0	0	0
Ret.ExistSCR & Scrub	119	0	0
Ret.SCR	0	216	18
Ret.ExistScrub & SCR	0	0	0
Ret.SNCR	0	0	0
Ret.ExistScrub & SNCR	0	0	0
Ret.SCR+Scrb	24	0	0
Ret.SNCR+Scrub	0	0	0
Ret.O/G SCR	0	0	0
Ret.O/G SNCR	0	0	0
CT Early Retirement	0	0	0
CC Early Retirement	0	0	0
O/G Early Retirement	0	0	48
Coal Early Retirement	0	0	0
Nuke Early Retirement	0	0	0
Total	**602**	**3360**	**1531**

Table 8.9. Generation (GWh) by Plant Type in the Canadian IPM Base Case 2004

Plant Type	2010	2015	2020
Scrubbed Coal_Nox	7297	7297	7297
Scrubbed Coal	6761	6761	6761
Unscrubbed Coal_Nox	5089	5089	5089
Unscrubbed Coal	77813	76203	76068
Oil/Gas Steam	5840	4079	3656
Oil/Gas Steam_Nox	8373	7484	7484
Nuclear	94922	94922	94922
Hydro	357646	367397	379183
Comb.Cycle Gas	11007	12692	21756
IGCC	0	0	0
Turbine	0	0	54
Biomass	13372	13372	13372
Landfill Gas	102	102	102
Wind	1853	1853	1853
Non Fossil_Other	1001	1001	1001
Fossil_Other	197	197	197
Cgn_Gas	33770	38552	39054
Cgn_Oil	3101	1587	552
Rep.Coal-CC	0	0	0
Rep.O/G-CC	3638	24401	27173
Rep.Coal-IGCC	0	0	0
Ret.Scrubber	7071	7071	7071
Ret.ExistSCR & Scrub	2162	2162	2162
Ret.SCR	6336	7947	8081
Ret.ExistScrub & SCR	0	0	0
Ret.SNCR	0	0	0
Ret.ExistScrub & SNCR	0	0	0
Ret.SCR+Scrb	4309	4309	4309
Ret.SNCR+Scrub	0	0	0
Ret.O/G SCR	0	0	0
Ret.O/G SNCR	0	0	0
CT Early Retirement	0	0	0
CC Early Retirement	0	0	0
O/G Early Retirement	0	0	0
Coal Early Retirement	0	0	0
Nuke Early Retirement	0	0	0
Total	**651663**	**684480**	**707200**

Table 8.10. Capacity Factors (%) by Plant Type in the Canadian IPM Base Case 2004

Plant Type	2010	2015	2020
Scrubbed Coal_Nox	85	85	85
Scrubbed Coal	85	85	85
Unscrubbed Coal_Nox	85	85	85
Unscrubbed Coal	85	85	85
Oil/Gas Steam	16	13.4	12.2
Oil/Gas Steam_Nox	70.3	85	85
Nuclear	79.7	79.7	79.7
Hydro	57.4	57.5	57.4
Comb.Cycle Gas	77.4	80.6	85.3
IGCC	N/A	N/A	N/A
Turbine	0	0	0.2
Biomass	87.7	87.7	87.7
Landfill Gas	90	90	90
Wind	41.4	41.4	41.4
Non Fossil_Other	90	90	90
Fossil_Other	90	90	90
Cgn_Gas	64.3	73.4	74.3
Cgn_Oil	48.9	39.2	20.5
Rep.Coal-CC	N/A	N/A	N/A
Rep.O/G-CC	90.4	90.4	90.4
Rep.Coal-IGCC	N/A	N/A	N/A
Ret.Scrubber	85	85	85
Ret.ExistSCR & Scrub	85	85	85
Ret.SCR	85	85	85
Ret.ExistScrub & SCR	N/A	N/A	N/A
Ret.SNCR	N/A	N/A	N/A
Ret.ExistScrub & SNCR	N/A	N/A	N/A
Ret.SCR+Scrb	85	85	85
Ret.SNCR+Scrub	N/A	N/A	N/A
Ret.O/G SCR	N/A	N/A	N/A
Ret.O/G SNCR	N/A	N/A	N/A
CT Early Retirement	0	0	0
CC Early Retirement	0	0	0
O/G Early Retirement	0	0	0
Coal Early Retirement	0	0	0
Nuke Early Retirement	N/A	N/A	N/A
Total	**60.4**	**61.7**	**62**

Table 8.11. The Canadian IPM Base Case 2004 Regional Emissions Summary in 2010

Model Region	Generation (1000 GWh)			Fuel Use (TBtu)			NO_x Emissions (MTons)			SO_2 Emissions (MTons)
	Winter	Summer	Total	Winter	Summer	Total	Winter	Summer	Total	Total
NF	4	2	5	8	3	11	3	1	4	15
NL	24	11	35	0	0	0	0	0	0	0
PE	0	0	0	0	0	0	0	0	0	0
NS	7	5	12	62	48	110	16	12	28	142
NB	15	12	26	132	106	238	15	13	28	82
QC	119	71	190	54	44	98	1	3	4	7
ON	104	76	180	825	614	1,439	28	22	50	145
MB	20	15	35	6	5	11	1	1	1	1
SK	11	8	19	111	82	193	23	18	41	109
AB	43	32	75	410	307	717	60	46	106	140
BC	45	30	74	52	51	103	4	4	8	2
Canadian Total	**391**	**261**	**652**	**1,660**	**1,260**	**2,919**	**150**	**119**	**269**	**643**

Table 8.12. The Canadian IPM Base Case 2004 Technology Emissions Summary in 2010

Plant Type / Retrofit	Generation (1000 GWh)			Fuel Use (TBtu)			NO_x Emissions (MTons)			SO_2 Emissions (Mtons)
	Winter	Summer	Total	Winter	Summer	Total	Winter	Summer	Total	Total
Total Biomass	8	6	13	65	51	116	8	6	13	5
Total CC Early Retirement	0	0	0	0	0	0	0	0	0	0
Total Cgn Gas	20	14	34	159	108	267	10	8	18	0
Total Cgn Oil	2	2	3	14	14	28	3	4	7	18
Total Coal Early Retirement	0	0	0	0	0	0	0	0	0	0
Total Comb. Cycle Gas	7	4	11	50	34	85	2	2	4	0
Total CT Early Retirement	0	0	0	0	0	0	0	0	0	0
Total Fossil Other	0	0	0	1	1	1	0	0	0	0
Total Hydro	224	134	358	0	0	0	0	0	0	0
Total Landfill Gas	0	0	0	1	0	1	0	0	0	0
Total Non Fossil Other	1	0	1	6	4	10	0	0	0	0
Total Nuclear	55	40	95	586	423	1,009	0	0	0	0
Total O/G Early Retirement	0	0	0	0	0	0	0	0	0	0
Total Oil/Gas Steam	3	2	6	35	24	59	6	5	11	26
Total Oil/Gas Steam Nox	4	4	8	45	45	90	5	4	9	23
Total Rep.O/G-CC	2	2	4	15	11	26	0	0	0	0
Total Ret. Exist SCR & Scrub	1	1	2	12	9	21	0	0	1	2
Total Ret. SCR	4	3	6	33	26	59	1	1	2	34
Total Ret. SCR+Scrb	2	2	4	23	18	41	1	0	1	3
Total Ret. Scrubber	4	3	7	38	30	67	7	5	12	5
Total Scrubbed Coal	4	3	7	37	29	66	6	5	11	5
Total Scrubbed Coal NOx	4	3	7	38	30	68	1	1	2	3
Total Turbine	0	0	0	0	0	0	0	0	0	0
Total Unscrubbed Coal	43	34	78	477	379	856	100	79	179	488
Total Unscrubbed Coal NOx	3	2	5	27	21	48	1	1	1	30
Total Wind	1	1	2	0	0	0	0	0	0	0
Canada Total Across Fuel Types	**391**	**261**	**652**	**1,660**	**1,260**	**2,919**	**150**	**119**	**269**	**643**

Table 8.13. The Canadian IPM Base Case 2004 Regional Emissions Summary in 2015

Model Region	Generation (1000 GWh)			Fuel Use (TBtu)			NO_x Emissions (MTons)			SO_2 Emissions (MTons)
	Winter	Summer	Total	Winter	Summer	Total	Winter	Summer	Total	Total
NF	4	2	5	8	3	11	3	1	4	15
NL	24	11	35	0	0	0	0	0	0	0
PE	0	0	0	0	0	0	0	0	0	0
NS	7	5	13	65	50	115	15	12	27	142
NB	17	13	30	149	115	264	13	10	23	103
QC	125	74	200	54	44	98	1	3	4	7
ON	106	78	184	842	629	1,472	28	22	50	145
MB	20	15	35	6	5	11	1	0	1	1
SK	12	9	21	119	86	205	24	18	42	109
AB	47	35	82	436	327	762	59	46	105	140
BC	48	32	80	78	60	138	4	3	7	2
Canadian Total	**411**	**273**	**684**	**1,757**	**1,319**	**3,076**	**147**	**116**	**263**	**664**

Table 8.14. The Canadian IPM Base Case 2004 Technology Emissions Summary in 2015

Plant Type / Retrofit	Generation (1000 GWh)			Fuel Use (TBtu)			NO_x Emissions (MTons)			SO_2 Emissions (Mtons)
	Winter	Summer	Total	Winter	Summer	Total	Winter	Summer	Total	Total
Total Biomass	8	6	13	65	51	116	8	6	13	5
Total CC Early Retirement	0	0	0	0	0	0	0	0	0	0
Total Cgn Gas	23	15	39	184	119	303	12	8	21	0
Total Cgn Oil	1	1	2	8	6	15	1	1	2	0
Total Coal Early Retirement	0	0	0	0	0	0	0	0	0	0
Total Comb. Cycle Gas	7	5	13	56	41	97	2	2	4	0
Total CT Early Retirement	0	0	0	0	0	0	0	0	0	0
Total Fossil Other	0	0	0	1	1	1	0	0	0	0
Total Hydro	230	138	367	0	0	0	0	0	0	0
Total Landfill Gas	0	0	0	1	0	1	0	0	0	0
Total Non Fossil Other	1	0	1	6	4	10	0	0	0	0
Total Nuclear	55	40	95	586	423	1,009	0	0	0	0
Total O/G Early Retirement	0	0	0	0	0	0	0	0	0	0
Total Oil/Gas Steam	2	2	4	22	18	41	5	4	9	27
Total Oil/Gas Steam Nox	4	3	7	45	36	81	5	4	8	23
Total Rep.O/G-CC	14	11	24	100	76	176	1	1	2	40
Total Ret. ExistSCR & Scrub	1	1	2	12	9	21	0	0	1	2
Total Ret. SCR	4	4	8	42	33	74	1	1	2	41
Total Ret. SCR+Scrb	2	2	4	23	18	41	1	0	1	3
Total Ret. Scrubber	4	3	7	38	30	67	7	5	12	5
Total Scrubbed Coal	4	3	7	37	29	66	6	5	11	5
Total Scrubbed Coal NOx	4	3	7	38	30	68	1	1	2	3
Total Turbine	0	0	0	0	0	0	0	0	0	0
Total Unscrubbed Coal	42	34	76	469	372	841	98	78	176	481
Total Unscrubbed Coal NOx	3	2	5	27	21	48	1	1	1	30
Total Wind	1	1	2	0	0	0	0	0	0	0
Canada Total Across Fuel Types	**411**	**273**	**684**	**1,757**	**1,319**	**3,076**	**147**	**116**	**263**	**664**

Table 8.15. The Canadian IPM Base Case 2004 Regional Emissions Summary in 2020

Model Region	Generation (1000 GWh)			Fuel Use (TBtu)			NO_x Emissions (MTons)			SO_2 Emissions (MTons)
	Winter	Summer	Total	Winter	Summer	Total	Winter	Summer	Total	Total
NF	4	2	5	6	2	8	2	1	3	10
NL	24	11	35	0	0	0	0	0	0	0
PE	0	0	0	0	0	0	0	0	0	0
NS	7	6	13	65	50	115	15	12	27	142
NB	18	13	31	153	118	271	13	10	23	103
QC	133	79	212	54	44	98	1	3	4	7
ON	107	78	185	846	630	1,476	28	22	50	145
MB	20	15	35	6	5	11	1	1	1	1
SK	13	9	22	122	90	212	24	19	43	109
AB	48	37	85	447	337	783	59	46	105	140
BC	52	34	86	102	77	178	4	3	8	2
Canadian Total	**425**	**282**	**707**	**1,801**	**1,351**	**3,152**	**147**	**115**	**262**	**660**

Table 8.16. The Canadian IPM Base Case 2004 Technology Emissions Summary in 2020

Plant Type / Retrofit	Generation (1000 GWh)			Fuel Use (TBtu)			NO_x Emissions (MTons)			SO_2 Emissions (Mtons)
	Winter	Summer	Total	Winter	Summer	Total	Winter	Summer	Total	Total
Total Biomass	8	6	13	65	51	116	8	6	13	5
Total CC Early Retirement	0	0	0	0	0	0	0	0	0	0
Total Cgn Gas	23	16	39	186	122	308	13	8	21	0
Total Cgn Oil	0	0	1	3	2	5	0	0	1	0
Total Coal Early Retirement	0	0	0	0	0	0	0	0	0	0
Total Comb. Cycle Gas	12	9	22	93	69	161	3	2	5	0
Total CT Early Retirement	0	0	0	0	0	0	0	0	0	0
Total Fossil Other	0	0	0	1	1	1	0	0	0	0
Total Hydro	237	142	379	0	0	0	0	0	0	0
Total Landfill Gas	0	0	0	1	0	1	0	0	0	0
Total Non Fossil Other	1	0	1	6	4	10	0	0	0	0
Total Nuclear	55	40	95	586	423	1,009	0	0	0	0
Total O/G Early Retirement	0	0	0	0	0	0	0	0	0	0
Total Oil/Gas Steam	2	2	4	20	16	36	4	3	7	23
Total Oil/Gas Steam Nox	4	3	7	45	36	81	5	4	8	23
Total Rep.O/G-CC	15	12	27	111	85	196	1	1	2	40
Total Ret. ExistSCR & Scrub	1	1	2	12	9	21	0	0	1	2
Total Ret. SCR	5	4	8	42	34	76	1	1	2	42
Total Ret. SCR+Scrb	2	2	4	23	18	41	1	1	1	3
Total Ret. Scrubber	4	3	7	38	30	67	7	5	12	5
Total Scrubbed Coal	4	3	7	37	29	66	6	5	11	5
Total Scrubbed Coal NOx	4	3	7	38	30	68	1	1	2	3
Total Turbine	0	0	0	1	0	1	0	0	0	0
Total Unscrubbed Coal	42	34	76	468	372	840	98	78	176	480
Total Unscrubbed Coal NOx	3	2	5	27	21	48	1	1	1	30
Total Wind	1	1	2	0	0	0	0	0	0	0
Canada Total Across Fuel Types	**425**	**282**	**707**	**1,801**	**1,351**	**3,152**	**147**	**115**	**262**	**660**