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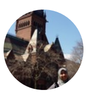

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Optimization Model for Energy Planning with CO_2 Emission Considerations

Haslenda Hashim, Peter Douglas, Ali Elkamel,* and Eric Croiset

Department of Chemical Engineering, University of Waterloo, Waterloo, Ontario N2L 3G1, Canada

This paper considers the problem of reducing CO_2 emissions from a power grid consisting of a variety of power-generating plants: coal, natural gas, nuclear, hydroelectric, and alternative energy. The problem is formulated as a mixed integer linear program (MILP) and implemented in GAMS (General Algebraic Modeling System). Preprocessing and variable elimination strategies are used to reduce the size of the model. The model is applied to an existing Ontario Power Generation (OPG) fleet analyzed under three different operating modes: (1) economic mode, (2) environmental mode, and (3) integrated mode. The integrated mode combines the objectives of both the economic and environmental modes through the use of an external pollution index as a conversion factor from pollution to cost. Two carbon dioxide mitigation options are considered in this study: fuel balancing and fuel switching. In addition, four planning scenarios are studied: (1) a base-load demand, (2) a 0.1% growth rate in demand, (3) a 0.5% growth rate in demand, and (4) a 1.0% growth rate in demand. A sensitivity analysis study is carried out to investigate the effect of parameter uncertainties such as uncertainties in natural gas price, coal price, and retrofit costs on the optimal solution. The optimization results show that fuel balancing can contribute to the reduction of the amount of CO_2 emissions by up to 3%. Beyond 3% reductions, more stringent measures that include fuel switching and plant retrofitting have to be employed. The sensitivity analysis results indicate that fluctuations in gas price and retrofit costs can lead to similar fuel-switching considerations. The optimal carbon dioxide mitigation decisions are found, however, to be highly sensitive to coal price.

Introduction

CO_2 is the main greenhouse gas and is suspected to be the principal gas responsible for global warming and climate change. Fossil-fuel power-generation plants are being challenged to comply with the Kyoto Protocol developed by the United Nations Framework Convention on Climate Change (UNFCC). For Canada, the Kyoto Protocol prescribed a legally binding greenhouse gas emission reduction target of 6% below 1990 levels by 2008−2012.

Ontario Power Generation (OPG) produces 70% of Ontario's electricity. Approximately 28.5% of OPG electricity is produced through the combustion of fossil fuels, 27% through hydroelectricity, and 44% through nuclear energy, and the remaining 0.5% comes from renewable or other energy sources, such as wind turbines. In 2002, OPG had about 22211 MW total in-service capacity, generated about 115.8 TW·h of electricity and emitted approximately 36.7 million tonnes (Mt) of CO_2, mainly from coal-fired power plants.[1]

There are several possible strategies to reduce the amount of CO_2 emitted from fossil-fuel power plants. Potential approaches include increasing plant efficiency, employing fuel balancing or fuel switching, making enhanced use of renewable energy (e.g., wind turbines, solar, biomass, fuel cells), and employing CO_2 capture and sequestration. All of these approaches are attractive, but with the exception of fuel switching, they are unlikely to have a major effect on overall CO_2 reductions in the short to medium term. In this paper, we focus on two possible options for reducing CO_2 emissions by a certain target while maintaining the electricity supplied to the grid at nominal levels. The options being considered are fuel balancing and fuel switching. Fuel balancing is the optimal adjustment of the operation of generating stations to reduce CO_2 emissions without making structural changes to the fleet. In contrast, fuel switching, which is switching from carbon-intensive fuels (i.e., coal) to less carbon-intensive fuels (e.g., oil or natural gas), involves structural changes to the fleet.

Many authors have applied the tools of systems analysis to the economic evaluation of environmental problems.[2−13] Kohn,[7] for instance, proposed a simple linear programming model that can determine a suitable air-pollution-control strategy for a given situation. The model did not consider long-range trends or technological developments. Schweizer[8] developed a method for the optimal mix of high-and low-sulfur fuels for power plants so that environmental criteria are met and plant operating schedules are preserved. Lou et al.[9] used linear programming analysis for the optimal arrangement of pollution-control equipment among various pollution sources. Jackson and Wohlers[10] developed a comprehensive model to determine the costs of controlling air pollution in a metropolitan area. Their model was based on (1) identifying air pollutants and emission sources, (2) specifying all feasible control methods for each pollutant, and (3) predicting the interrelations that can occur in the dynamic setting of the region. The model permits the determination of the percent use of lowest-cost solutions. Kemner[11] developed an integer programming model to select a set of controls that can meet a given emission restriction at the lowest cost. The model was applied to a coke plant and was solved by

* To whom correspondence should be addressed. Tel.: (519) 888-4567 ext 7157. Fax: (519) 746-4979. E-mail: aelkamel@cape.uwaterloo.ca.

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trial and error using plots of the control costs for various desired reductions. Holnicki[12] presented a similar model for implementing a pollution-control strategy at a regional scale. This approach is related to the optimal allocation of funds for emission reduction in a given set of power station installations. Elkamel et al.[13] presented comprehensive mixed integer linear programming models that can determine the optimum set of control or retrofit options for a given pollution problem, along with control setup times.

Of all the works on air pollution abatement, only a few have dealt with CO_2 mitigation in power-generation expansion planning. Genchi et al.,[14] for instance, developed a prototype model for designing regional energy supply systems. Their model calculates a regional energy demand and then recommends a most effective combination of 11 different power supply systems to meet required CO_2 emissions targets with minimum cost. The new energy system to be installed included cogeneration systems, a photovoltaic cell system, unused energy in sewage and garbage incineration, and a solar-energy water supply. Linares et al.[15] proposed a group decision multiobjective programming model for electricity planning in Spain based on goal programming (GP). The objective was to minimize the total cost of the electricity generation; the emissions of CO_2, SO_2, and NO_x; and the production of radioactive waste. The model is capable of estimating the capacity to be installed for the year 2020 under four different social groups: regulators, academics, electric utilities, and environmentalists. The preferences of the groups were expressed as weights in the model that affected the different main criteria in the objective function. Mavrotas et al.[16] developed a mixed 0−1 multiple-objective linear programming (MOLP) model and applied it to the Greek electricity generation sector to identify the number and output of each type of power unit needed to satisfy an expected electricity demand. The first objective was to minimize the annual electricity production cost, and the second objective addressed the minimization of the total amount of SO_2 emissions. However, the model did not consider CO_2 mitigation and sequestration. Bai and Wei[17] developed a linear programming model to evaluate the effectiveness of possible CO_2 mitigation options for the electricity sector in Taiwan. The strategies they considered included fuel alternatives, reduced peak loads, energy conservation, power-generation efficiency improvements, and CO_2 capture. They found that the combination of reduced peak production and increased power-plant efficiency with CO_2 conservation was an effective strategy to meet significant CO_2 emissions reduction targets. Climaco et al.[18] developed new techniques that incorporate multiple-objective linear programming and demand-side management (DSM). These techniques are able to determine the minimum expansion cost by changing the levels and forms of electricity use by the consumers and generating alternatives from the supply side. The model also considered the emissions caused by electricity production. Noonan et al.[19] studied and developed an optimization program for planning investments in electricity-generating systems. The optimization program determined the mix of types of plants, sizes of the individual plants to be installed, and allocation of installed capacity to minimize total discounted cost while meeting the system's forecasted demand for electricity. This problem is referred to as the generation planning problem (GPP). To comply with the variation in electricity demand, the electricity demand to be met was described by a load duration curve (LDC). The mathematical model was solved using Benders' decomposition method (BDM). The model was applied to the New England Generation Planning Task Force.

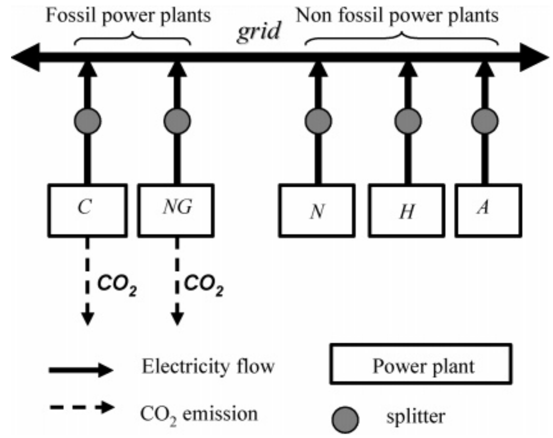

Figure 1. Superstructure for an existing fleet of electricity-generating stations.

In the present paper, a mathematical programming model based on a superstructure of alternatives is presented and applied to an existing power-generation system. Three modes of operation are considered: an economic mode, an environmental mode, and an integrated mode. The economic mode is based solely on an economic objective, the environmental mode uses the minimization of CO_2 emissions as its objective, and the integrated mode combines the two objectives in an appropriate way as will be explained shortly.

Four electricity generation scenarios are considered to investigate fuel-balancing options as well as structural changes for different growth alternatives: (1) a base-load demand and (2) low-growth (0.1%), (3) medium-growth (0.5%), and (4) high-growth (1.0%) scenarios. A sensitivity analysis was also performed to evaluate the impact of natural gas prices, coal prices, and retrofit costs on the optimal configuration of the OPG fleet of electricity-generating stations.

Methodological Approach

(1) Superstructure Representation. The superstructure representing a power-generation energy-supply system and fuel alternatives is presented here. The following notation is adopted throughout the paper: C, NG, O, N, H, and A represent a set of coal, natural gas, oil, nuclear, hydroelectric, and alternative energy power plants, respectively. Figure 1 presents a configuration of power stations. The mix of all electricity generated is injected into the electricity grid, and it is assumed at this stage that there is no CO_2 capture at any existing power-generating unit. Figure 2 illustrates the fuel-balancing technique to decrease CO_2 emissions by adjusting the operation of the fleet of existing electricity-generating stations, e.g., increasing the load on existing non-fossil-fuel power plants and decreasing the load on existing fossil-fuel power plants. In this case, it is desired to determine the optimal load distribution for all power stations to maintain electricity to the grid while reducing CO_2 emissions to a certain target. Figure 3 illustrates another technique, the so-called fuel-switching technique, that represents switching from

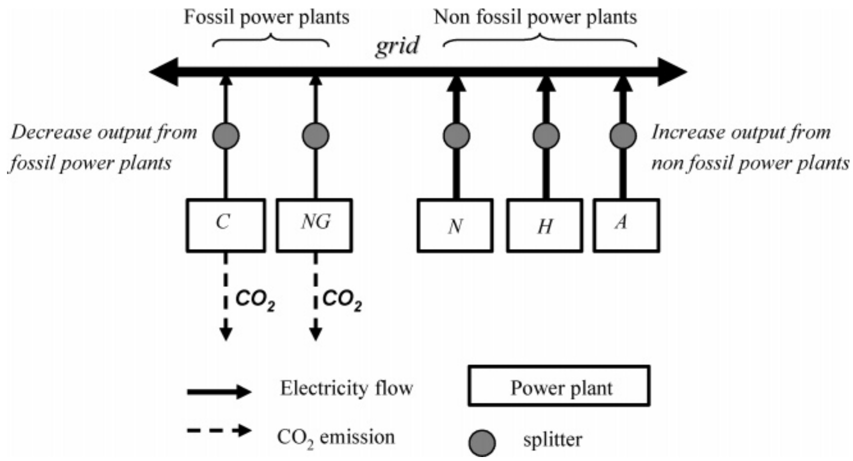

Figure 2. Superstructure for fuel balancing (increase output of non-fossil-fuel plants and decrease output from fossil-fuel plants).

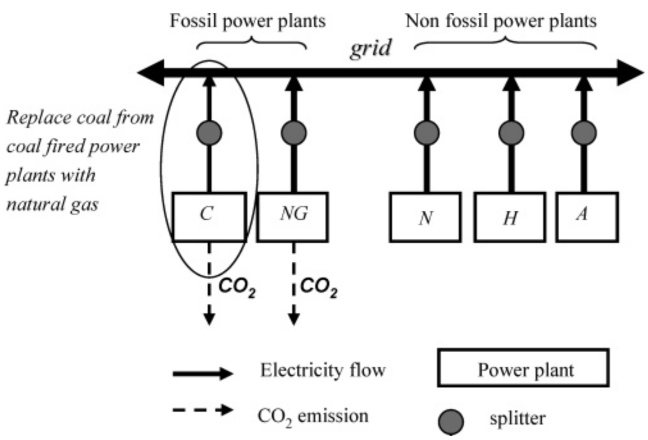

Figure 3. Superstructure for fuel switching (switching from more carbon-intensive fuels to less carbon-intensive fuels, e.g., switching from coal to natural gas).

carbon-intensive fuels to less carbon-intensive fuels (e.g., switching from coal to natural gas).

(2) Model Formulation. The optimization problem to be studied in this paper can be formulated as follows: For a given CO_2 reduction target, what is the best generating-plant load distribution and mix of fuels that will maintain the electricity supply to the grid? Three different points of view or modes for the optimization problem are considered: (1) economic mode, (2) environmental mode, and (3) integrated mode. The corresponding optimization models are formulated below. Three types of variables are first defined: (1) continuous variables, E_{ij}, representing electricity generated/load distribution from the ith fossil-fuel boilers; (2) continuous variables, E_i, representing electricity generated/load distribution from the ith nuclear, hydroelectric, or alternative energy power plant; and (3) binary variables, X_{ij} representing the type of fuel used in a given fossil-fuel plant

$$X_{ij} = \begin{cases} 1 & \text{if fuel } j \text{ is used in plant } i \\ 0 & \text{otherwise} \end{cases}$$

We first state the objective functions for the three modes of operation considered and discuss the model constraints in a separate section.

(3) Objective Function. (a) Mode 1: Economic Mode. In this mode of CO_2 mitigation, the objective is to satisfy a CO_2 reduction target and maintain and enhance power to the grid. The cost function in this mode includes the operating cost of electricity generated for the fleet of generating stations and the retrofitting cost associated with switching the fuel from coal to natural gas for the fossil-fuel stations. Note that, in the case of a fossil-fuel station already operating on gas ($j = 1$), there is no retrofitting cost involved (i.e., $R_{i1} = 0$).

The objective function for this mode is given by

$$\min Z_1 = \sum_{i\in F}\sum_{j} C_{ij}E_{ij} + \sum_{i\in \mathrm{NF}} C_iE_i + \sum_{i\in F}\sum_{j} R_{ij}X_{ij} \quad (1)$$

where C_{ij} is the electricity generation cost per MW·h if fuel j is used in fossil-fuel power plant i; C_i is the electricity generation cost per MW·h for non-fossil-fuel power plant i; E_i is the electricity generated (MW·h/year) by non-fossil-fuel power plant i; E_{ij} is the electricity generated (MW·h/year) by fossil-fuel power plant i when using fuel j; R_{ij} is the retrofitting cost to switch a coal power station to natural gas power station, expressed in U.S. dollars per $/year; X_{ij} is a binary variable that indicates which fuel to use or whether the plant should be shut down at each fossil-fuel plant i; F is the set of fossil-fuel power stations including coal and natural gas; and NF is the set of non-fossil-fuel power stations, including nuclear, hydroelectric, and wind turbine sources. Note that, in the case of non-fossil-fuel plants, no associated binary variables are defined, as the fuel type for these plants is known a priori.

(b) Mode 2: Environmental Mode. In environmental mode, the objective is to minimize the CO_2 emissions while maintaining and enhancing power to the grid. The optimization model can be written as

$$\min Z_2 = \sum \mathrm{CO}_{2ij}E_{ij} \quad (2)$$

where CO_{2ij} represents the CO_2 emissions for the ith fossil-fuel power station using fuel j and is calculated using basic chemical equations that relate the generation of CO_2 emissions to the quantity and quality of fuel burned

$$\mathrm{CO}_{2ij} = 0.03667\mathrm{EF}_{ij} \quad (3)$$

where 0.03667 is the conversion factor from coal to CO_2 and EF_{ij} is the CO_2 emissions factor of the ith fossil-fuel station using fuel j

$$\mathrm{EF}_{ij} = \frac{1}{\eta_{ij}}\left(\frac{\%\mathrm{C}}{\mathrm{HHV}}\right) \quad (4)$$

where η_{ij} is the efficiency of the coal-fired boiler in the ith fossil-fuel station operating on fuel j. %C represents the percentage carbon content of the fuel, and HHV is the fuel higher heating value.

(c) Mode 3: Integrated Mode. This mode combines the previous two objective functions to give

$$\min Z_3 = \sum_{i\in F}\sum_{j} C_{ij}E_{ij} + \sum_{i\in \mathrm{NF}} C_iE_i + \sum_{i\in F}\sum_{j} R_{ij}X_{ij} + \beta\sum_{i\in F}\sum_{j}(\mathrm{CO}_{2ij})E_{ij} \quad (5)$$

The CO_2 emissions in eq 5 are translated into U.S. dollars per \$/year by introducing a CO_2 emissions cost coefficient β. More details on this coefficient is given in the case study. The reason for considering this integrated mode is to find compromise decisions under both economic and environmental objectives. If only economics is considered, then emissions will be unacceptable. Likewise, if only an environmental objective is considered, then plant economics will not be sustained.

(4) Constraints. The minimization of the objective functions represented by eqs 1, 2, and 5 is subjected to the following constraints:

(a) Energy Balance/Demand Satisfaction. The total electricity generation must be equal to or greater than the desired electricity demand

$$\sum_{i\in \mathrm{NF}} E_i + \sum_{i\in F}\sum_{j} E_{ij} \geq \text{demand} \quad (6)$$

(b) Fuel Selection and Plant Shutdown. For each fossil-fuel process i, either the process is operating with one chosen fuel, or it is shut down

$$\sum_{j} X_{ij} \leq 1 \qquad \forall i \in F \quad (7)$$

(c) Capacity Constraints.

$$E_{ij} \leq M \sum_{j} X_{ij} \qquad \forall i \in F \quad (8a)$$

$$E_i \leq M \qquad \forall i \in \mathrm{NF} \quad (8b)$$

The above constraint set places an upper bound on energy produced from the different plants. It also ensures that the energy production from fossil-fuel plants ($i \in F$) is zero when no fuel is assigned to the plant and a decision to shut down the plant has been made. The parameter M is any large number and represents an upper bound on energy production from each plant i. M can be chosen to be the maximum installed capacity of $E_i^{\max}$ for a non-fossil-fuel plant or $E_{ij}^{\max}$ for a fossil-fuel plant.

(d) Upper Bound on Operational Changes. The electricity generated by unit i cannot exceed the current electricity generation for the unit by r_i (the maximum increase in the base load due to operational constraints)-Comparing constraints 8b and 9b, it is clear that both

$$E_{ij} \leq (1 + r_i)E_{ij}^{\mathrm{current}} \qquad \forall i \in F \quad (9a)$$

$$E_i \leq (1 + r_i)E_i^{\mathrm{current}} \qquad \forall i \in \mathrm{NF} \quad (9b)$$

represent an upper bound on E_i. Because constraints 9b are tighter, constraints 8b are redundant and do not have to be included in the model. Constraints 8a, on the other hand, include binary decision variables and are essential in the model implementation, especially in the case of plant shutdowns.

(e) Lower Bound on Operational Constraints. The annual capacity factor for each power plant must be greater than some minimum; otherwise, the plants will be shut down

$$f_{ij} \geq l_{ij}X_{ij} \qquad \forall i \in F$$

$$f_i \geq l_i \qquad \forall i \in \mathrm{NF} \quad (10)$$

where l_{ij} (l_i) is the minimum annual capacity factor for fossil-fuel (non-fossil-fuel) power station i and f_{ij} (f_i) is the corresponding annual capacity factor. The relationship between the annual capacity factor and electricity generation is given by

$$E_{ij} = f_{ij}E_{ij}^{\max} \qquad \forall i \in F$$

$$E_i = f_iE_i^{\max} \qquad \forall i \in \mathrm{NF} \quad (11)$$

where $E_{ij}^{\max}$ ($E_i^{\max}$) is the installed capacity of the ith fossil-fuel (non-fossil-fuel) power plant.

(f) Emission Constraint. In this constraint, annual CO_2 emissions must satisfy a CO_2 reduction target

$$\sum_{i\in F}\sum_{j} \mathrm{CO}_{2ij}E_{ij} \leq (1 - \%\mathrm{CO}_2)\mathrm{CO}_2 \quad (12)$$

where CO_{2ij} represents the CO_2 emissions for the ith fossil-fuel power plant using the jth fuel per unit of electricity generated (t of CO_2/MW·h). %CO_2 is the percentage reduction target. CO_2 represents the current CO_2 emissions in millions of tonnes per year.

(g) Nonnegativity Constraints. The electricity generated from all power plants must be greater than zero; therefore, the amounts of electricity generated from non-fossil-fuel and fossil-fuel power plants are defined as positive/nonnegative variables.

$$E_i \geq 0, \quad E_{ij} \geq 0 \quad (13)$$

(h) Extra Constraints. Other constraints can be imposed on the model. These include (1) geographical/management constraints, according to which certain power plants are assigned to supply certain locations while other plants cannot supply some specific locations, and (2) fuel or resource constraints, according to which the fuel supply (i.e., natural gas) is limited by pipeline capacity.

Case Study for Ontario Power Generation (OPG)

Currently, OPG operates 79 electricity-generating stations, 5 of which are coal-fired generating stations, Ci (i = 1−5); 1 of which is a natural gas generating station, NGi (i = 6); 3 of which are nuclear generating stations, Ni (i = 7−9); 69 of which are hydroelectric generating stations, Hi (i = 10−78); and 1 of which is a small wind turbine, Ai (i = 79). At nominal levels, OPG generates 13765 MW of electricity that it injects into the grid from a mix of sources, i.e., coal, hydroelectric, nuclear, and renewable energy. No CO_2 capture process currently exists at any OPG power plant; about 36.7 Mt of CO_2 was emitted in 2002, mainly from fossil-fuel power plants. There are 27 fossil-fuel boilers at the 6

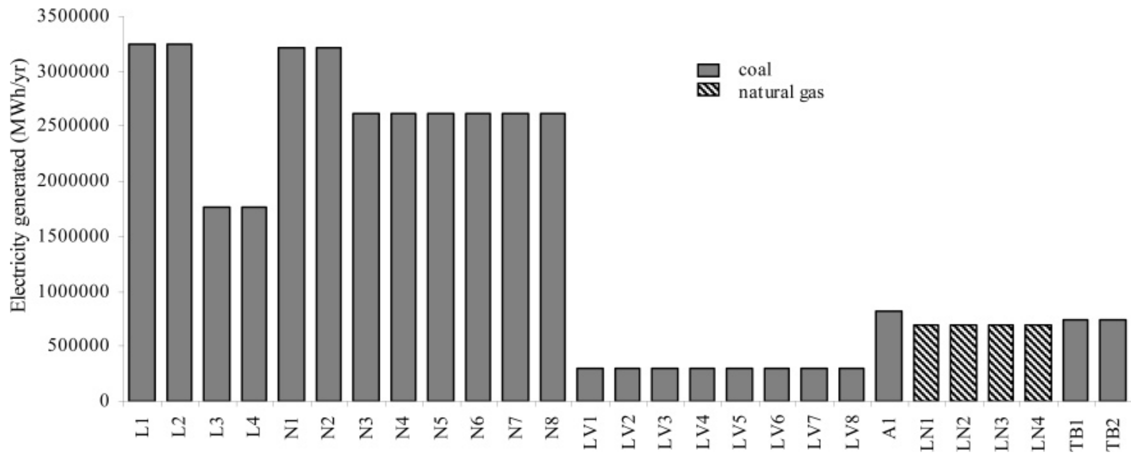

Figure 4. OPG's current electricity generation by fossil fuels.

Table 1. Ontario Power-Generation Fossil-Fuel Generating Stations

station	fuel	installed capacity (MW)	number of units	annual capacity factor	operating cost ($/MW·h)	CO_2 emission rate (t/MW·h)
Nanticoke 1 (N1)	coal	500	2	0.75	30	0.9300
Nanticoke2 (N2)	coal	500	6	0.61	30	0.9300
Lambton1 (L1)	coal	500	2	0.5	34	0.9386
Lambton2 (L2)	coal	500	2	0.75	25	0.9384
Lakeview (LV)	coal	142	8	0.25	35	0.9765
Lennox (LN)	natural gas	535	4	0.15	50−70	0.6510
Thunder Bay (TB)	coal	155	2	0.55	30	1.0230
Atitokan (A)	coal	215	1	0.44	30	1.0230

fossil-fuel stations: 4 boilers at Lambton (L1−L4), 8 boilers at Nanticoke (N1−N8), 8 boilers at Lakeview (LV1−LV8), 1 boiler at Atikokan (A1), 4 boilers at Lennox (L1−L4), and 2 boilers at Thunder Bay (TB1−TB2). Currently, 4 boilers operated by Lennox are running on natural gas.

A summary of OPG's current fossil-fuel generating stations is contained in Table 1. The operational costs for nuclear, hydroelectric, and wind turbine were estimated to be $32, $5, and $4/MW·h, respectively. Note that, currently, natural gas is the most expensive fuel used by OPG.[13] In this study, we assumed that all coal-fired boilers operate at 35% efficiency and that the base-load demand is constant throughout the year at 13675 MW. Because the main objective of this paper is to study CO_2 emissions reduction through fuel balancing and fuel switching, no attempt was made to study the effect of improved technology. An improvement in boiler technology will, in principle, lead to an efficiency higher than our assumed efficiency of 35%.

The index i ($i = 1-79$) represents all of OPG's power plants, including those powered by fossil-fuel, nuclear, hydroelectric, and wind turbine sources. The index j ($j = 1$ or 2) represents the fuel selection, $j = 1$ (coal) or 2 (natural gas). The retrofitting cost was estimated to be $30 million/1000 MW with a 20-year lifetime and a 10% annual interest rate. To translate CO_2 emissions into cost, we used an external cost index of $\beta = \$0.03$ US$/kg of CO_2 emitted as developed in a recent United Nations publication.[20] The reserve margin, r_i, for load distribution for all of OPG's fleet power plants was set at 1% higher than the current level because of operational considerations. The lower bound was set to be 10% (i.e., a plant has to be operated with at least 10% of its installed annual capacity factor; otherwise, it will be shut down). Figure 4 provides a summary of current electricity generation from OPG's fossil-fuel power stations by the 27 different boilers. Currently, only four boilers are operating on natural gas. This figure will later be used in our analysis to check which optimal modifications must be made under different modes of operations.

Results and Discussions

This section presents the results for the three modes of operation analyzed under four different scenarios: (1) base-load demand, (2) low-growth (0.1% growth rate) demand, (3) medium-growth (0.5% growth rate) demand, and (4) high-growth (1.0% growth rate) demand.

The implications relating to the amount of electricity generated by each boiler and generating station, the total cost of electric power generation, and the CO_2 emissions are discussed. The models were implemented in the GAMS (General Algebraic Modeling System) optimization package and solved using the mixed integer linear programming (MILP) solver.[21] Given that the generation of electricity can be increased by r_i from the current load, the load distribution of the non-fossil-fuel power plants can be determined a priori. This is because they do not emit any CO_2, and their operational cost is less than that of the fossil-fuel plants. Therefore, all non-fossil-fuel power plants can be excluded from the optimization process, and we need to solve only for the remaining variables that correspond to the electricity generation, E_{ij}, from OPG's 27 fossil-fuel units and the binary variables that correspond to decisions on which fuel to use in each plant and whether any retrofitting action is required.

Mode 1: Economic Mode. In this mode, the objective is to minimize the total operating cost while meeting a specified CO_2 reduction target. The optimization results for the case of 3% CO_2 reduction indicate that no fuel switching is needed. In other words, this objective can be obtained simply by adjusting the

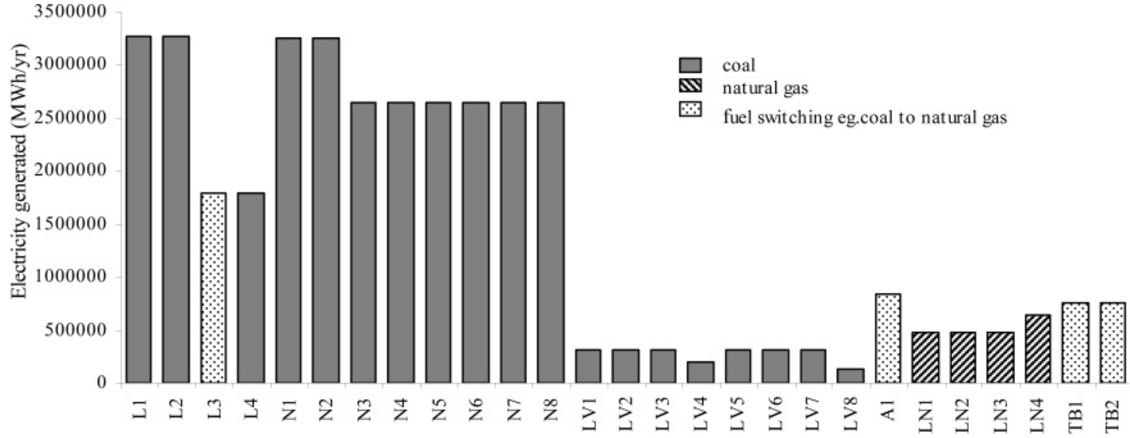

Figure 5. Optimal electricity generation strategy for fossil-fuel boilers for a 6% CO_2 reduction requirement.

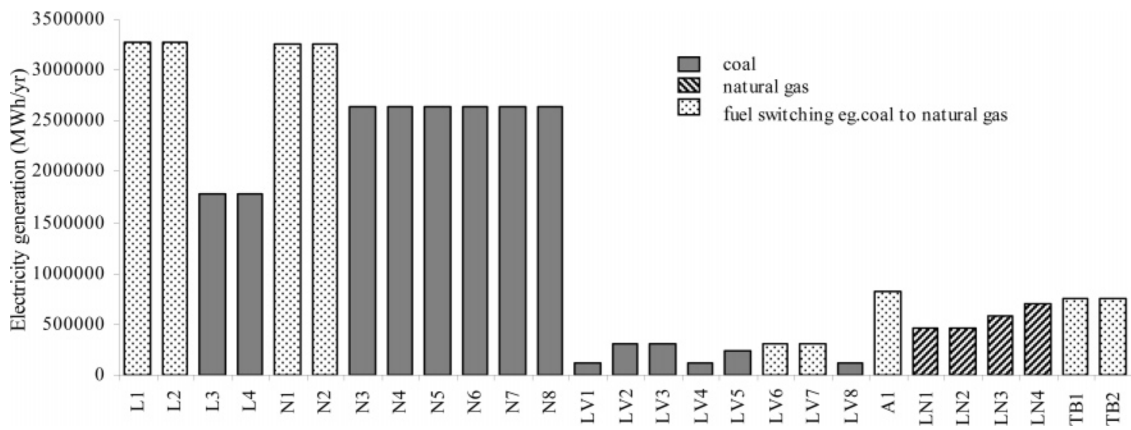

Figure 6. Optimal electricity generation strategy by fossil-fuel boilers for a 20% CO_2 reduction requirement.

operation of the current boilers, e.g., increasing the load from existing non-fossil-fuel power plants and decreasing the load from existing fossil-fuel power plants (fuel balancing). The results show that the total cost is also reduced by 2.4% by reducing electricity generation from all four natural gas boilers by 32.1% and from the two coal-fired boilers (LV4 and LV8) by 33.4% and 59.4%, respectively. The electricity generation from other fossil-fuel boilers and non-fossil-fuel power plants was increased by 1% higher than the nominal operational level to maintain the electricity to the grid.

To achieve more than 3% CO_2 reduction, it was found that fuel switching must be implemented. This involves fleet changes from coal to natural gas. The optimization results show, for instance, that to achieve 6% CO_2 reduction (Canada's Kyoto target at 1990) while maintaining the electricity to the grid at minimum cost, the electricity generation from three natural gas boilers (LN1, LN2, and LN3) needs to be reduced by 32.1%; that from one natural gas boiler (LN4) by 8.2%; and that from two coal-fired boilers (LV1 and LV2) by 59.4% and 34.8%, respectively, and the electricity generation from the other coal-fired boilers and non-fossil-fuel power plants needs to be increased by 1% over the nominal operational level. Finally, four coal-fired boilers (L1, A1, TB1, TB2) need to be switched to natural gas, resulting in a cost increase of about 1.2% (Figure 5).

It is estimated that Canada's emissions will rise to approximately 750 Mt by 2005 from 571 Mt in 1990. Therefore, the actual reduction target is to reduce emissions to 179 Mt by 2008−2012, and this represents a reduction of more than 20%.[22] Figure 6 illustrates the breakdown of electricity production by boilers for a 20% CO_2 reduction. In this case, nine coal boilers are switching to natural gas (compared to only four for the case of a 6% CO_2 reduction). Higher CO_2 reduction targets require more coal boilers to be switched to natural gas.

The effect of increasing demand on the amounts of electricity generated by the different boilers was also analyzed. Three different scenarios were studied, involving low (0.1%), medium (0.5%), and high (1.0%) growth rates in electricity demand. The analysis shows that fuel switching is required to satisfy CO_2 emissions reductions as electricity demand is increased. For a 0.1% growth rate in demand, a 3% CO_2 reduction can be achieved by fuel balancing by increasing electricity generation for all coal-fired boilers by 1% and decreasing electricity generation for all four natural gas boilers without having to change the fleet structure. However, for a 0.5% growth rate in demand and a 3% CO_2 reduction, one coal-fired boiler needs to be switched to natural gas. As the growth rate in demand increases further to 1%, three coal-fired boilers need to be switched to natural gas, as shown in Figure 7.

Figures 8 and 9 illustrate the effect of growth rate in demand on CO_2 emissions and total cost for a 3% CO_2 reduction target. As the growth rate in demand increases from 0 to 1%, the optimizer adjusts coal-fired boilers to produce more electricity up to their maximum level. CO_2 emissions increase until they hit the CO_2 emissions target (e.g., 3% CO_2 reduction). Then, the optimizer switches coal-fired boilers to natural gas while maintaining the electricity output at the current level. This results in an instant drop in CO_2 emissions because natural gas emits less CO_2; however, the total cost

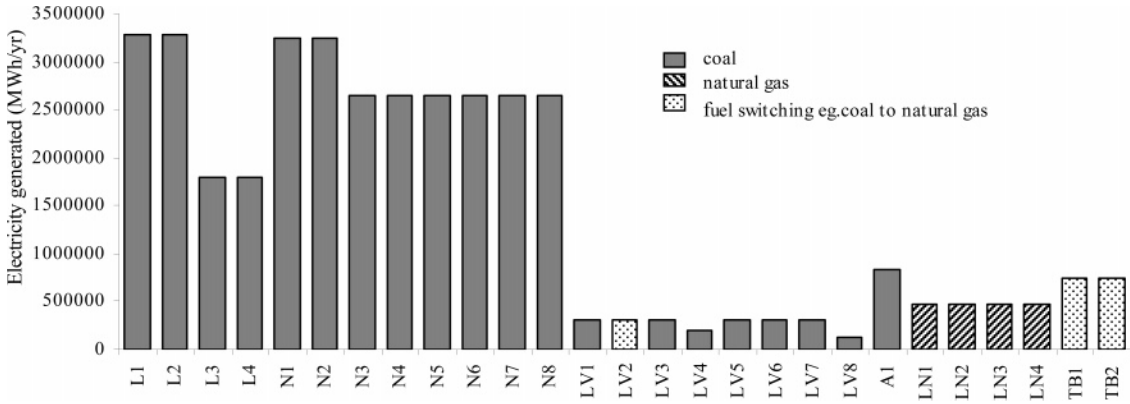

Figure 7. Effect of a 1% increase in electricity demand on fleet structure for a 3% CO_2 reduction target.

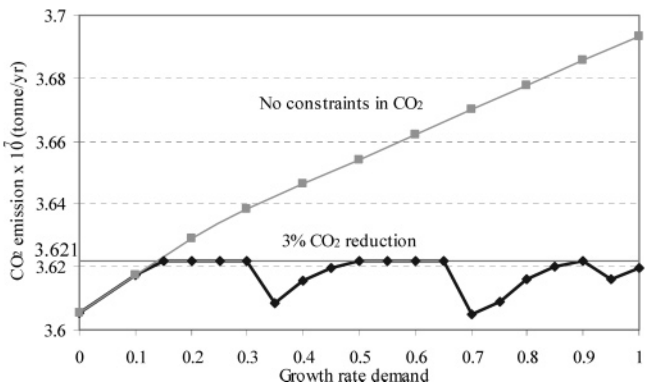

Figure 8. Effect of electricity demand growth rate on CO_2 emissions for a 3% CO_2 reduction requirement.

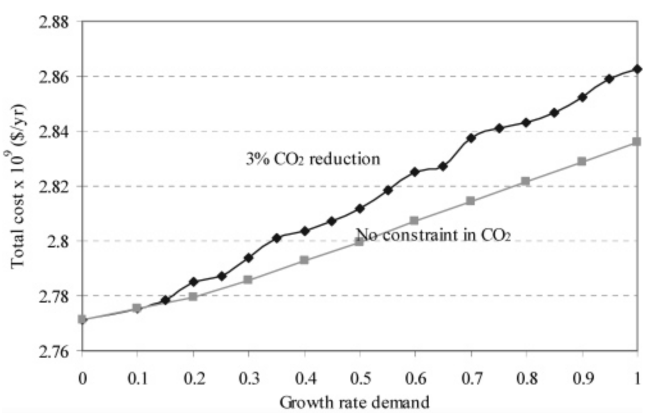

Figure 9. Effect of electricity demand growth rate on fleet operating cost with and without a 3% CO_2 reduction.

continues to rise because natural gas is more expensive than coal. The negative slope indicates that natural gas boilers generate more electricity up to a maximum level while coal boilers operate at their maximum level to meet the demand. This trend is repeated to meet the demand and CO_2 emissions target.

Mode 2: Environmental Mode. In this mode, the goal is to minimize CO_2 emissions. The optimizer minimized the CO_2 emissions by switching all 23 coal-fired boilers to natural gas. For the base-load demand, a 39.5% CO_2 reduction was achieved after optimization because all coal-fired boilers were switched to natural gas, resulting in an increased cost of $467.5 million/year. As a consequence, minimization of CO_2 emissions is considered to be very costly because an increase in growth rate in demand will require the use of more natural gas to produce the required electricity target. Figures 10 and 11 give optimal electricity generation by the different plants to meet the base demand and an increased demand of 1%, respectively. The figures also illustrate the fuel-switching scenarios for the various fossil-fuel plants.

Mode 3: Integrated Mode. The solution generated from the different modes (economic and environmental) produced different results. For example, minimizing the total cost resulted in large CO_2 emissions, and minimizing CO_2 resulted in large costs. These are conflicting strategies between minimizing cost and CO_2 emissions, as shown in Tables 2 and 3. This is not surprising because there is a cost associated with CO_2 emissions reduction, and therefore, cost minimization will avoid reducing emissions. A more realistic mode is therefore one that integrates both modes and seeks a compromise between minimizing cost and minimizing CO_2 emissions. In this mode, as explained earlier, eq 5 is used as the objective function. Figure 12 represents optimization results for this mode of operation for a 1.0% electricity demand growth rate and a 3% CO_2 emissions reduction. Comparing these results with the results of Figure 7 (pure economic mode) and Figure 11 (pure environmental mode), it is clear that a compromise is achieved. The number of boilers switching from coal to natural gas is substantially less than that of the environmental mode. The same switching pattern is observed, however, as in the economic mode, except that, for the integrated mode, two gas boilers are required to operate at higher loads. The optimal solutions to meet 3% and 6% reductions in CO_2 emissions are reported in Tables 2 and 3 (fourth row), respectively. The results for the base electricity demand case, the case of 1% electricity demand increase, and other cases are reported in these tables.

Sensitivity Analysis

In this section, the impact of the natural gas and coal prices and retrofit costs on the configuration of power plants for a 20% CO_2 emissions reduction is discussed. The sensitivity analysis was performed for four case studies: 0% (base-load demand), 0.1%, 0.5%, and 1.0% growth rates in demand. Three major parameters were considered as follows: (1) natural gas price (10% and 20% higher than the base-case natural gas price), (2) coal price (10% and 20% higher than the base-case coal price), and (3) retrofit cost (−10%, −20%, +10%, and + 20% changes from the base-case retrofit cost).

Although it is possible for energy prices (natural gas and coal) to decrease, it was assumed that the most

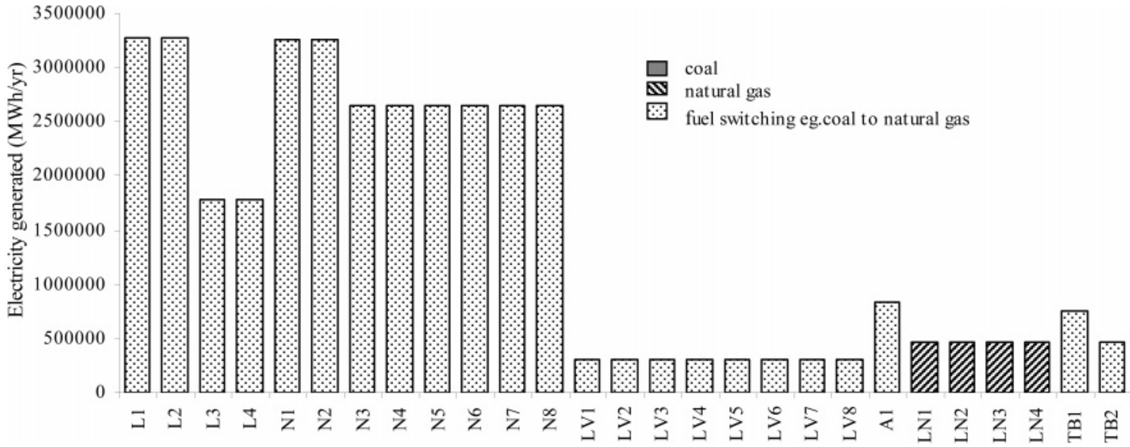

Figure 10. Optimization results for electricity generation to meet a base-load demand under the objective of minimizing CO_2 emissions.

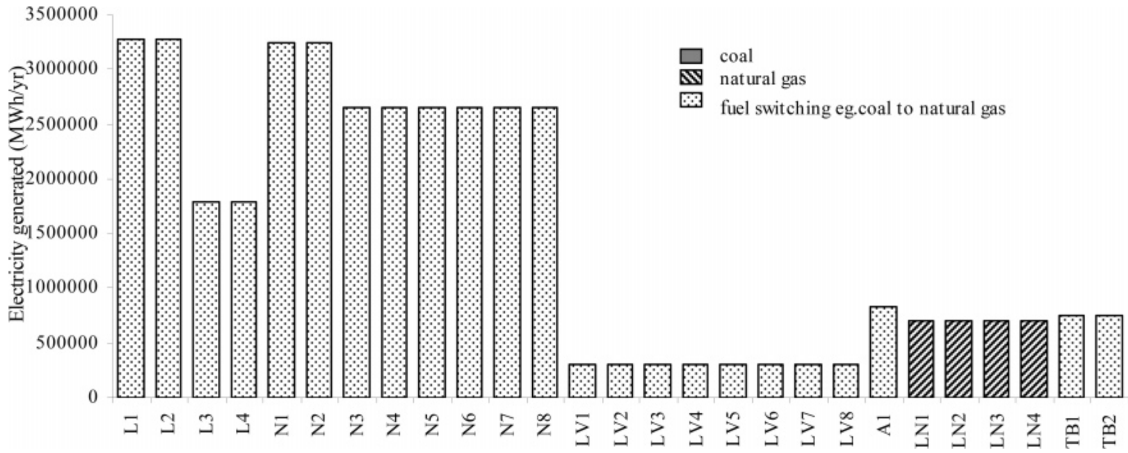

Figure 11. Optimization results for electricity generation to meet a 1% increased demand under the objective of minimizing CO_2 emissions.

Table 2. Conflict Results between Cost and CO_2 Emissions for a 3% CO_2 Reduction

case	total cost (10^6\$/year)	CO_2 emissions (Mt/year)
	Nominal Mode, Reference	
base	2837.0	37.33
	Economic Mode, Minimize Total Cost	
base	2771.0	36.05
0.1%	2775.2	36.19
0.5%	2812.0	36.17
1.0%	2862.4	36.21
	Environmental Mode, Minimize CO_2 Emissions	
base	3304.5	22.11
0.1%	3309.8	22.18
0.5%	3335.9	22.49
1.0%	3372.1	22.89
	Integrated Mode, Minimize (Total Cost + CO_2 Emissions)	
base	3852.1	36.06
0.1%	3860.4	36.17
0.5%	3898.5	36.22
1.0%	3948.4	36.19

Table 3. Conflict Results between Cost and CO_2 Emissions for 6% CO_2 Reduction

case	total cost (10^6\$/year)	CO_2 emissions (Mt/year)
	Nominal Mode, Reference	
base	2837.0	37.33
	Economic Mode, Minimize Total Cost	
base	2804.9	35.09
0.1%	2818.2	35.09
0.5%	2852.9	35.09
1.0%	2909.7	34.99
	Environmental Mode, Minimize CO_2 Emissions	
base	3304.5	22.11
0.1%	3309.8	22.18
0.5%	3335.9	22.49
1.0%	3372.1	22.89
	Integrated Mode, Minimize (Total Cost + CO_2 Emissions)	
base	3866.2	35.09
0.1%	3871.1	35.09
0.5%	3905.9	35.09
1.0%	3951.5	34.99

reasonable scenarios were increasing costs. On the other hand, in the case of retrofitting costs, we felt that this cost was perhaps uncertain and that it was worth considering both positive and negative deviations in the retrofit cost estimate. According to Canada's Energy Outlook 1996−2020, the natural gas price is expected to increase from \$2.25/GJ in 1997 to \$3.25/GJ by 2020.[23] Figure 13 illustrates all 27 boilers divided into six groups, corresponding to the six fossil-fuel generating stations. The first column presenting a pattern by black and white dots illustrates OPG's current operation without a CO_2 emissions target; this is the base case. Other columns showing the optimal pattern for 0%, 0.1%, 0.5%, and 1.0% growth rates in demand with 20% CO_2 emissions reduction for base natural gas price are also presented. The black dots represent coal-fired

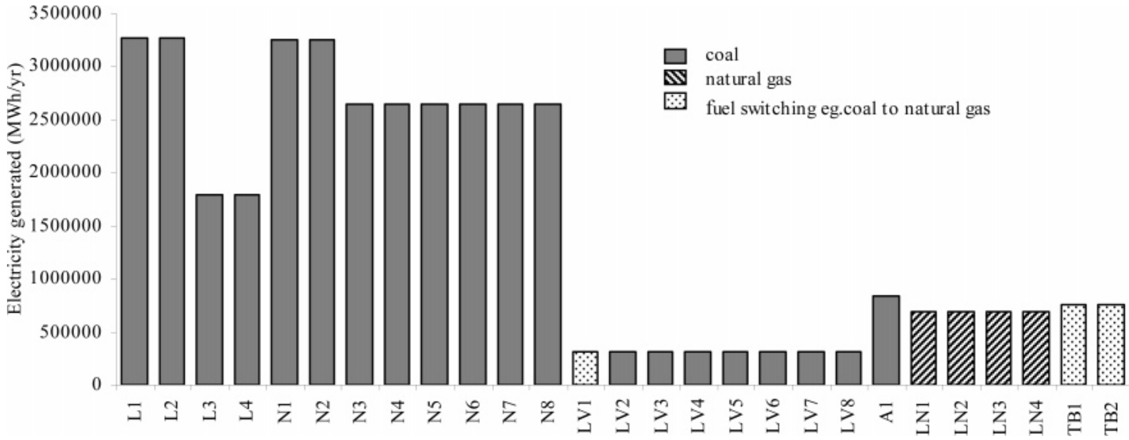

Figure 12. Electricity generation strategy for a high (1.0%) growth rate in demand and a 3% CO_2 reduction for the integrated mode of operation.

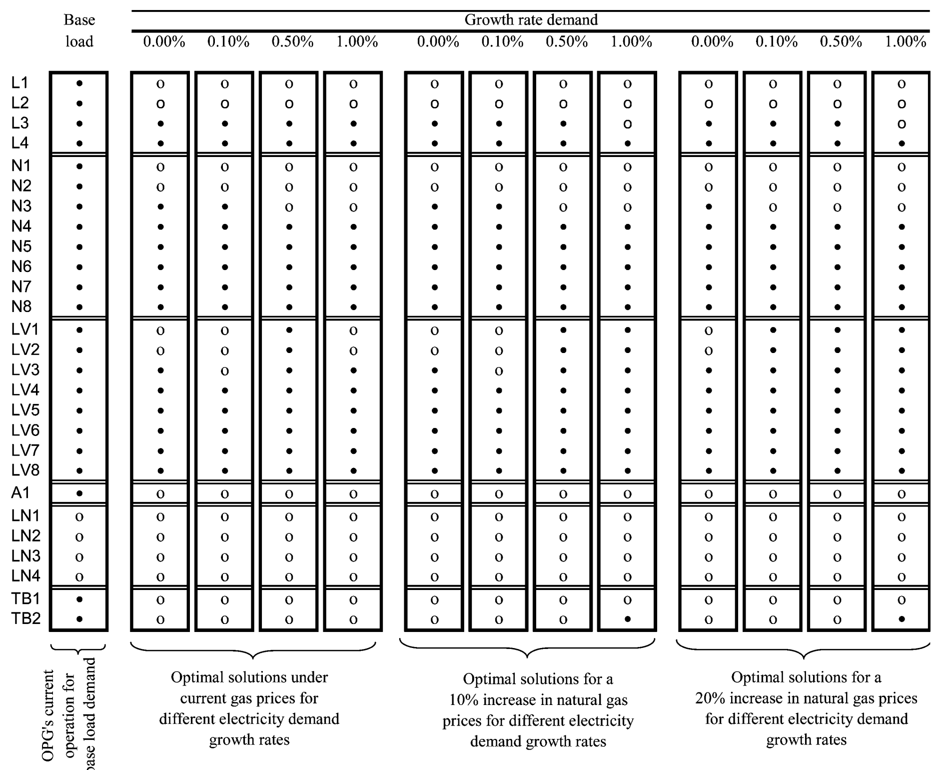

Figure 13. Effect of increasing natural gas prices on fuel-switching decisions for different electricity demand growth rates.

boilers, whereas the open or white dots represent natural gas boilers. As can be seen, increasing demand from the base load to 0.1% leads to switching of more coal-fired boilers to natural gas to meet CO_2 emissions reduction target. In the case of a 0.5% growth rate in demand, a large coal-fired boiler (N3) is switched to natural gas to meet demand increase and CO_2 emissions target. It is important to note that the smaller boilers (LV1−LV3) that are switched to natural gas for the cases of 0% and 0.1% growth rates in demand switch back to coal. This is because the switching of N3 results in a large reduction in CO_2 emissions and a large increase in cost; by switching LV1, LV2, and LV3 back to coal, a significant reduction in cost occurs, along with a modest increase in CO_2 emissions. At higher demands (1.0% increase growth rate in demand), 10 coal-fired boilers are switched to natural gas compared to eight boilers for the previous case. The pattern remains unchanged if the natural gas price is increased by 10% and 20% from the base natural gas price for the case of 0%, 0.1%, and 0.5% growth rates in demand. However, the location of the optimum is changed for the case of a 1.0% growth rate in demand. For higher demand, the optimizer favored switching the larger coal-fired boiler (N4) rather than several small boilers; this strategy by the optimizer results in three small boilers switching back to coal (LV1, LV2, and TB1).

The variation of coal price has a significant impact on the optimal configuration of power plants, as illustrated in Figure 14. Increasing the price of coal by 10% and 20% from the base coal price results in changed patterns as compared to the base-case scenario for all of the different demand rates. A similar pattern is observed for 10% and 20% increases in coal price for all scenarios except that with a 0% growth rate in demand.

The location of the optimal configuration was less sensitive to the retrofit cost in the range between −10%

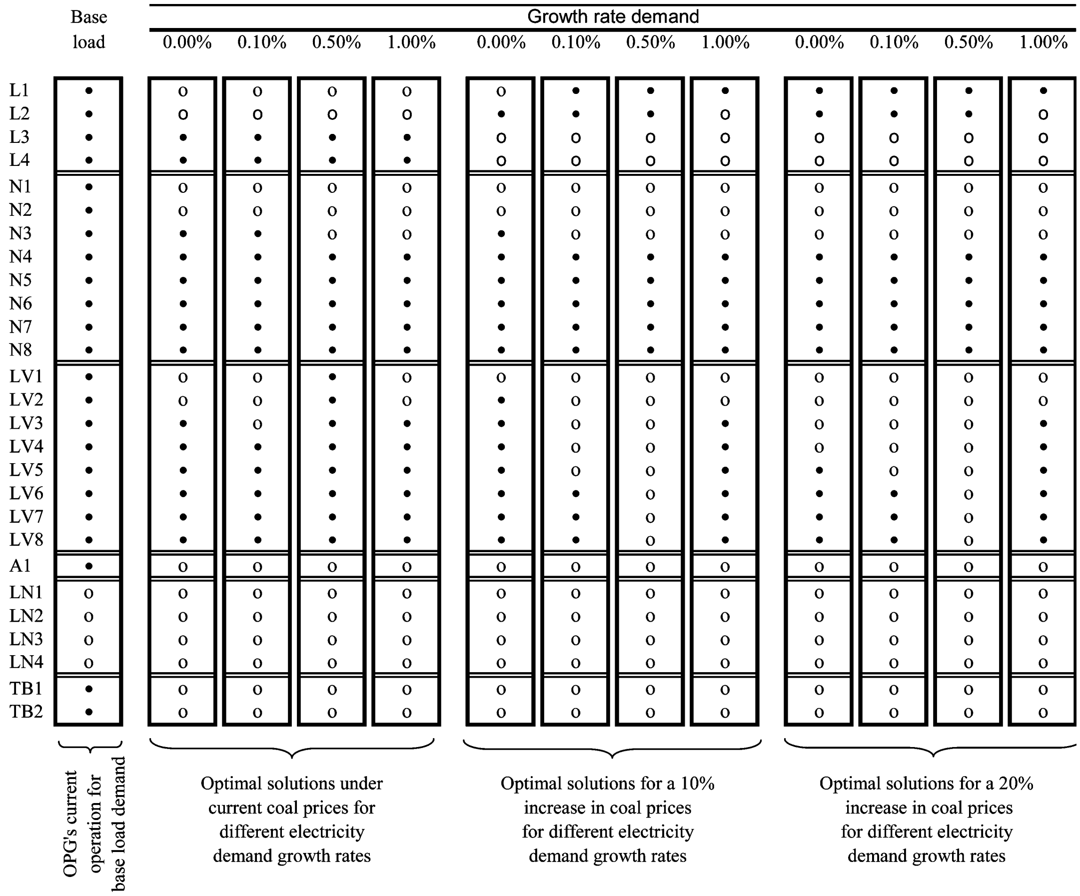

Figure 14. Effect of increasing coal prices on fuel-switching decisions for different electricity demand growth rates.

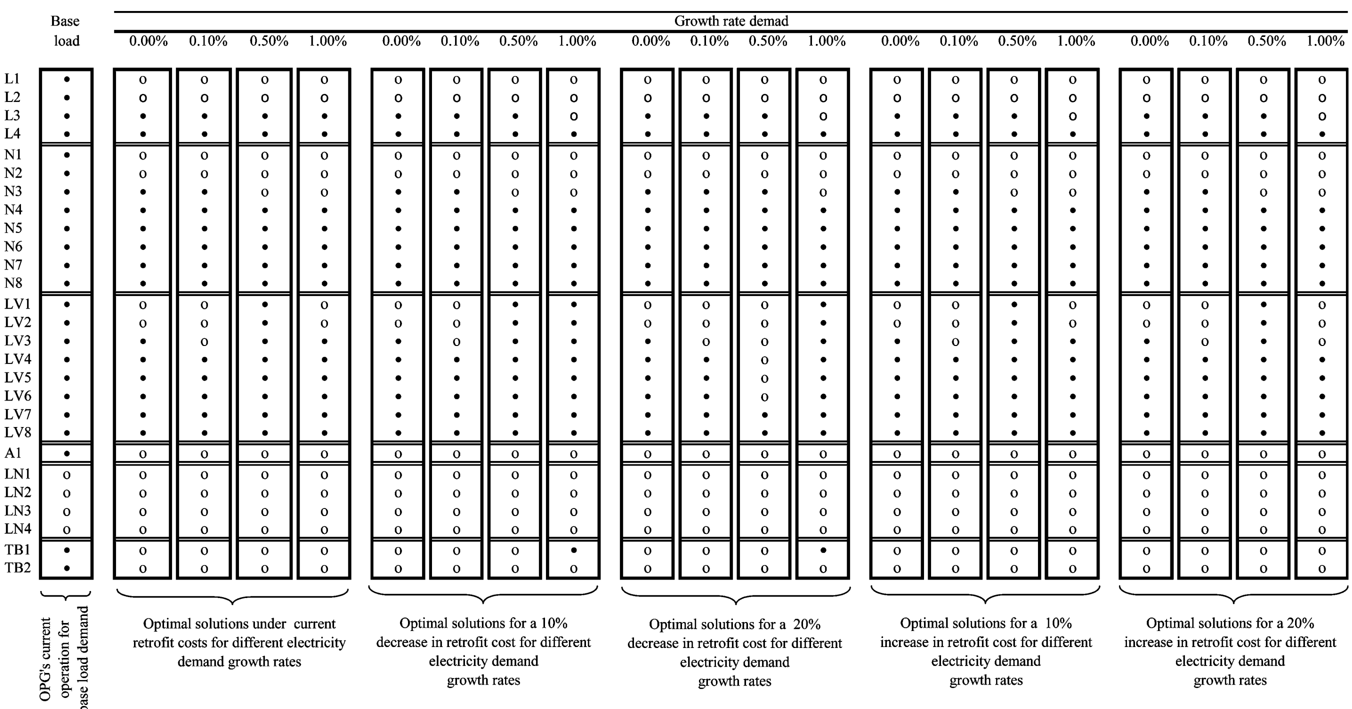

Figure 15. Effect of retrofit cost on fuel-switching decisions for different electricity demand growth rates.

and +20% from the base retrofit cost, as illustrated in Figure 15. As a result, a similar pattern is produced at the same growth rate in demand for different retrofit costs. This agrees with the pattern produced by varying the natural gas price for all four cases.

The results of the sensitivity analysis show that the variation of fuel prices directly affects the total cost. The optimal configuration or fuel-switching pattern of the fleet also changes when the retrofit cost is varied. This is not surprising because, if the fuel price and retrofit costs are increased, this will definitely lead to an increase in total cost.

Conclusions and Future Directions

This work represents the initial stage of an effort to consider the large-scale optimization of CO_2 emissions from the Ontario power grid. The optimization problem was formulated as a mixed integer linear program (MILP) and was implemented in GAMS. The MILP model was applied to OPG's existing power plants as a first attempt to evaluate the best solution for OPG's power plants under three different operating strategies: total cost reduction, CO_2 emissions reduction, and an integrated operational mode. The optimization results indicate that fuel balancing and fuel switching are effective ways to reduce CO_2 emissions. Preliminary optimization results show that overall CO_2 emissions can be reduced by 3% or less by adjusting OPG's current operational level without having to change the fleet structure (fuel balancing). Fuel balancing also results in a reduction of operating costs by 2.4%. However, if CO_2 emissions are to be reduced further (e.g., by >6%, Canada's Kyoto target), it will be necessary to employ structure changes such as fuel switching. Indeed, this solution leads to increases in the total cost because it involves retrofitting cost and use of natural gas, which is currently OPG's most expensive fuel. Minimizing the CO_2 emissions implied a very large cost ($467.5 million/year) because the optimizer rightly decided to switch all coal-fired boilers to natural gas regardless of the price of the fuel.

If higher CO_2 emissions reductions, greater than 40%, are required, it will be necessary to employ CO_2 capture and sequestration technologies. However, CO_2 capture processes are energy-intensive and require large amounts of supplemental energy, not to mention the existence of large geological reservoirs for CO_2 storage. The supplemental energy requirements for CO_2 capture processes can be supplied by the fossil-fuel plant itself, energy from the grid, special-purpose power plants built to supply the CO_2 capture energy, or an oversized power plant built to supply both the CO_2 capture energy and additional energy to the grid. These issues will be discussed in another paper.

The sensitivity analysis shows that similar fuel-switching patterns are observed when the natural gas price and retrofit cost are varied for different growth rates in demand. However, the coal price directly affected the optimal configuration or fuel-switching pattern of the fleet. The solutions generated from different modes produced different results because there are conflicts between minimizing cost and minimizing CO_2 emissions. It is likely that government regulations will be imposed, and therefore, economic mode (minimizing cost while satisfying a CO_2 reduction target) will be satisfactory. However, in the absence of governmental regulations, the use of a compromise programming model will have to be considered.

The analysis used in this paper was static in the sense that the electricity generation was held constant. However, in real situations, there is high variability in electricity demand. The demand can be represented by load duration curves, and the model presented in this paper can be utilized for such situations as well by invoking it for different (e.g., high, low, medium) demands.

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Nomenclature

A = set of alternative energy power plants
C = set of coal energy power plants
C_i = operating cost per unit of electricity generated
%C = percentage of carbon for specific type of fuel
EF_i = emission factor for plant i
E_i = electricity generated by the ith type of power plant (MW·h/year)
E_i^{max} = maximum amount of electricity generated by the ith type of power plant (MW·h/year)
E_{nom} = nominal amount of electricity generated by the ith type of power plant (MW·h/year)
f_i = capacity factor of the ith type of power plant
H = set of hydroelectric energy power plants
HHV_i = high heating value of specific fuel i (MJ/t)
N = set of nuclear energy power plants
N = number of power plants
NG = set of natural gas energy power plants
O = set of oil energy power plants
η_i = power-plant efficiency

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