Proceedings of the 1st International Conference on Natural Resources Engineering & Technology 2006
24-25th July 2006; Putrajaya, Malaysia, 549-561

CO_2 Mitigation for a Network of Power Plants Using Mathematical Programming

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Abstract

This paper presents a case study focusing on the structural optimization of Ontario Power Generation, OPG's fleet of power plants to meet a given CO_2 reduction target by minimizing the cost of electricity (COE). The optimization takes into account the possible implementation of carbon capture and storage (CCS) and the possibility of constructing new power plants, with or without CCS, to maintain or increase electricity to the grid depending on the growth in electricity demand. The model is formulated as Mixed Integer Non Linear Programme (MINLP) and implemented in GAMS (General Algebraic Modeling System). Exact linearization techniques were employed to facilitate solution development. Three mitigation options were considered in this study: fuel balancing (optimal adjustment of the operation of existing generating stations to reduce CO_2 emissions without making structural changes to the fleet), fuel switching (switching from carbon intensive fuel to less carbon intensive fuel, e.g. coal to natural gas) and retrofitting CCS on existing coal fired power plants. Both, fuel switching and retrofitting CCS involve structural changes on the existing fleet. The computer programme is capable of determining the best mix of fuel, annual capacity factor for existing power plants, location and size of CO_2 capture process and finally, construction of new state-of-the-art power plants, such as supercritical pulverized coal (PC), integrated gas combined cycle (IGCC) or natural gas combined cycle (NGCC) with and without CCS.

Keywords: Optimization, CO_2 emission, CO_2 mitigation, carbon capture and storage e(CCS)

1.0 Introduction

Canada signed The Kyoto Protocol, committing to reduce greenhouse gas (GHG) emissions that cause climate change by 6% compared to 1990 levels by 2012. In the year 2004, 20% of Canada's greenhouse gases, primary CO_2 emission was emitted from combustion of fossil fuel power plant. In Ontario, Ontario Power Generation (OPG) produces 75% of Ontario's electricity from mix of energy sources: coal accounts for 35% of OPG's electricity generating capacity, nuclear supplies 44%, hydroelectric 27%, and the remaining10% is renewable energy. As a major electricity production in Ontario, OPG generated 115 TWh electricity and was emitted about 36.7 million tonne of CO_2 in 2003. There are several promising strategies to reduce the amount of CO_2 emitted from fossil fuels power plants. The potential approaches include: improves power plant efficiency, fuel balancing (decrease capacity factor for coal fuel power

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plant, increase capacity factor for non fossil fuel power plant such as nuclear, hydroelectric and alternative energy), fuel switching (switching from carbon intensive fuels i.e. coal, to less carbon intensive fuels i.e. oil or natural gas), enhanced use of renewable energy (i.e. wind turbines, solar, biomass, fuel cells), and CCS. Fuel balancing is the optimal adjustment of the operation of generating stations to reduce CO_2 emissions without making structural changes to the fleet. On the other hand, fuel switching, which is switching from carbon intensive fuels to less carbon intensive fuels and CO_2 capture and sequestration involves structural changes to the fleet. Although fuel switching may be likely possible options, greater reduction of CO_2 from power plant flue gas in a short term is expected to be technically possible using CO_2 capture and sequestration. However, CCS would lead to a reduction in plant output due to energy supply for CO_2 capture process. In this paper, we will discuss 3 possible options to reduce CO_2 emission by a certain target while maintaining the electricity to the grid according to growth demand, this includes fuel balancing, fuel switching, and retrofitting CCS on existing fossil generating stations.

2.0 Methodology

2.1 Superstructure representation

Figure 1 shows a superstructure that represents all possible alternative configurations for producing the required electricity demand by the grid considering a CO_2 reduction target, fuel balancing or fuel switching, CO_2 capture process and sequestration technology containing a large number of feasible alternative configurations. C_i, NG_i, O_i, N_i, H_i and A_i represents existing coal, natural gas, oil, nuclear, hydroelectric and alternative energy power plants respectively. Hypothetical new power plants are represented by N_i^{new}, H_i^{new}, A_i^{new}, PC_i^{new}, NG_i^{new}, IG_i^{new} for nuclear, hydroelectric, alternative energy, PC, NGCC and IGCC with and without capture. $C\text{-}C_i$, $C\text{-}NG_i$, $C\text{-}O_i$, $C\text{-}N_i$, $C\text{-}H_i$, $C\text{-}A_i$, $C\text{-}N_i^{new}$, $C\text{-}H_i^{new}$, $C\text{-}A_i^{new}$, $C\text{-}PC_i^{new}$, $C\text{-}NG_i^{new}$, $C\text{-}IG_i^{new}$ represent possible CO_2 capture processes, and *Sequestration 1* and *2* represent the two potential locations

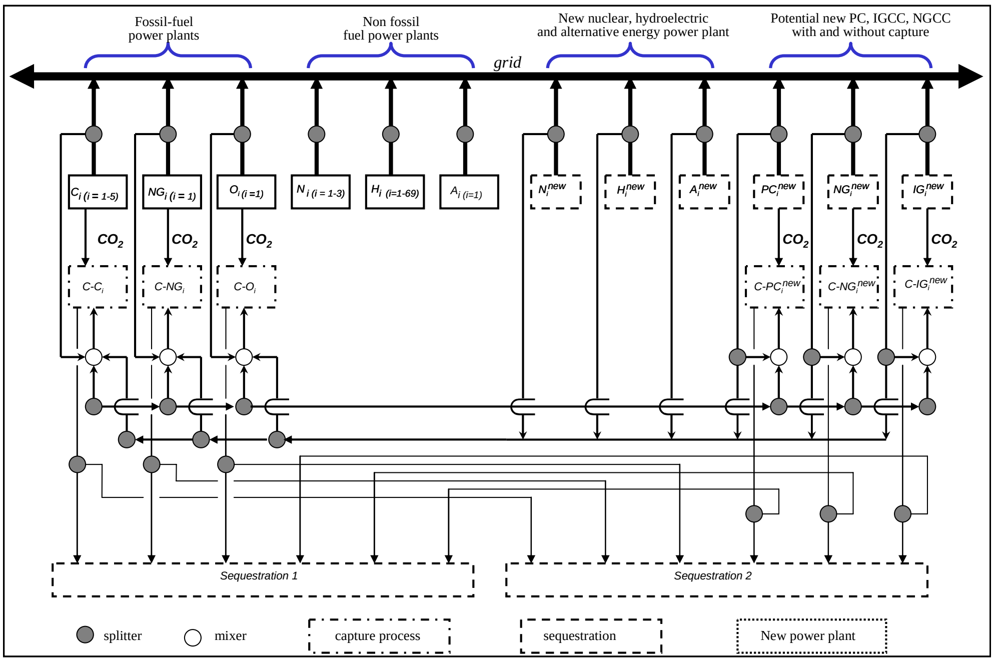

Figure 1 Generic superstructure

for sequestration in Ontario.

2.2 Model Formulation

The optimization problem to be studied in this paper can be formulated in words as: "*for a given CO_2 reduction target, what is the best generating plant load distribution, mix of fuels and CO_2 capture and sequestration to meet electricity demand growth?*" The objective of this study is to synthesize the OPG's existing fleet, incorporating CCS on existing coal-fired power plants and constructing hypothetical new power plants with or without capture to meet a given CO_2 reduction target while maintaining or enhancing electricity to the grid at the minimum overall cost. The cost function includes: operating cost of electricity generation for the fleet of generating stations, retrofitting cost associated with fuel switching from coal to natural gas, retrofitting cost for carbon capture retrofit on existing coal-fired power plants and capital and operational cost for hypothetical new power plants and sequestration cost. Note that in the case of a fossil fuel already operating on gas ($j = 1$), there is no retrofitting cost involved (i.e.$R_{i1} = 0$). The objective function is given by:

$$\underbrace{\sum_{i\in F}\sum_{j} C_{ij}E_{ij} + \sum_{i\in NF} C_i^{NF}E_i}_{\substack{\text{operational cost for}\\ \text{existing plants}}} + \underbrace{\sum_{i\in F^c}\sum_{j} R_{ij}X_{ij}}_{\text{retrofit cost}} + \underbrace{\sum_{i\in P^{new}} S_i^{new}E_i^{\max}y_i + \sum_{i\in P^{new}} C_i^{new}E_i^{new}}_{\substack{\text{capital and operationl cost}\\ \text{for new additional stations}}}$$
$$+ \underbrace{\sum_{i\in F^c}\sum_{k} S_{ik}^{c}z_{ik} + \sum_{i\in F^c}\sum_{k} C_k^c E_{ik}}_{\substack{\text{capital and operational cost}\\ \text{of carbon capture retrofit}}} + \underbrace{\sum_{i\in F^c\cup P^{new}}\sum_{s} C_{is}^{seq}\alpha_i\varepsilon_i w_{is}}_{\text{sequestration cost}} \quad (1)$$

where C_{ij} is the electricity generation cost per MWh if j^{th} fuel is used in i^{th} fossil-fuel boiler; C_i (C_i^{new}) is the electricity generation cost per MWh for i^{th} non-fossil-fuel power plant (i^{th} new hypothetical boiler); C_k^c is operational cost for k^{th} CO_2 capture process (\$/MWh); C_{is}^{seq} is sequestration cost from i^{th} boiler to s^{th} storage location (\$/tonne CO_2 captured); E_i (E_i^{new}) is the electricity generated (MWh/year) from i^{th} non-fossil-fuel power plant (i^{th} hypothetical boilers); E_{ij} is the electricity generated (MWh/year) from i^{th} fossil-fuel boilers when using j^{th} fuel; E_{ijk} is electricity required for k^{th} CO_2 capture process (MWh/year) incorporated in i^{th} coal-fired boiler which running with j^{th} fuel; R_{ij} is the retrofitting cost for switching i^{th} coal-fired boiler to j^{th} fuel (natural gas) express in US\$/year; S_i^{new} is capital cost for new power plant in \$/KW; S_{ik}^c is annualized capital cost for k^{th} capture process in \$/year; ε_{ik} is the fractional of CO_2 capture; X_{ij} is a binary variable that indicates fuel selection or whether the plant should be shut down for i^{th} fossil-fuel boiler; binary variable y_i, is represents existence/non existence of i^{th} hypothetical new boiler; binary variable z_{ik}, is introduced for the selection of k^{th} retrofit carbon capture on i^{th} existing coal-fired boiler; w_{is} is a binary variable that indicates the selection of s^{th} potential location for CO_2 sequestration; i is the set of existing fossil fuel boilers, non-fossil power plants and new hypothetical boilers with and without capture; j is the set of j^{th} fuel selection that consists of coal or natural gas; F is the set of fossil-fuel boilers including coal (F^c) and natural gas (F^{ng}); NF is the set of non-fossil-fuel power stations, including nuclear, hydroelectric, and wind turbine sources; and P^{new} is the set of hypothetical new boilers that includes pulverized coal, P^{PC} (P^{PCcap}), integrated gas combined cycle, P^{IGCC} ($P^{IGCCcap}$) and natural gas combined cycle, P^{NGCC} ($P^{NGCCcap}$) with and (without capture). 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.

The objective function represented by equation (1) is subjected to the following constraints:

a) Energy balance/demand satisfaction

The total electricity injected to the grid comes from existing non fossil power, from new hypothetical boilers (E_i^{NF}/E_i^{new}) and from fossil generating stations operating with j^{th} fuel, E_{ij}. The supplemental energy required, E_{ik} for CO_2 capture processes, however, results in an electricity reduction/power de-rate. Therefore, the net electricity generation for the whole fleet must be equal to or greater than the desired total electricity demand.

$$\left[\sum_{i\in NF} E_i^{NF} + \sum_{i\in P^{new}} E_i^{new} + \sum_{i\in F}\sum_{j} E_{ij}\right] - \sum_{i}\sum_{k} E_{ik} \geq \text{Demand} \qquad (2)$$

b) Energy balance on capture process

CO_2 capture processes are energy intensive. In this study, the energy for CO_2 capture process is consider to be extracted from the steam cycle of the existing fossil power plant itself as written in equation (3):

$$E_{ik} = \sum_{i\in F^c}\sum_{j} E_{ij}^{'} \qquad \forall i \in F^c, \forall k \qquad (3)$$

c) Capacity constraint on capture process

$$E_{ik} \leq z_{ik} E_k^{\max} \qquad \forall i \in F^c, \forall k \qquad (4)$$

The parameter E_k^{max} represents the maximum supplemental energy required for k^{th} capture technologies. It also ensures that the energy required for any k^{th} capture process is zero when no capture process is assigned to the i^{th} coal-fired boilers. Note that capture process considered to be incorporated only on coal-fired boilers because natural gas is less carbon intensive fuel which emit less amount of CO_2 emission.

d) Fuel selection and plant shut-down:

For i^{th} fossil fuel boilers, either the process is operating with one chosen fuel or is shut down.

$$\sum_{j} X_{ij} \leq 1 \qquad \forall i \in F \qquad (5)$$

e) Plant capacity constraints:

$$\sum_{j} X_{ij} \leq 1 \qquad \forall i \in F \qquad (6a)$$

$$E_i \leq M \qquad \forall i \in NF \qquad (6b)$$

$$E_i \leq M y_i \qquad \forall i \in P^{new} \qquad (6c)$$

The above constraint set upper bounds on energy produced from the different electricity generating stations. 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 of plant shut-down has been made. The parameter M is any large number and represents an upper bound on energy production for i^{th} non fossil power plants/new hypothetical boilers. M can be chosen to be the maximum installation capacity.

f) Upper bound on operational changes:

The electricity generated from the i^{th} unit cannot exceed the current electricity generation for the unit by r_i (the maximum increase in the base load, $E_i^{current}$ due to operational constraints).

$$E_{ij} \leq (1+r_i)E_i^{current} X_{ij} \qquad \forall i \in F, \forall j \qquad (7a)$$
$$E_i^{NF} \leq (1+r_i)E_i^{current} \qquad \forall i \in NF \qquad (7b)$$
$$E_i^{new} \leq E_i^{\max} y_i \qquad \forall i \in P^{new} \qquad (7c)$$

g) Lower bound on operational constraints:
The capacity factor must be greater tha n some minimum; otherwise the plants will be shut down.

$$f_{ij} \geq l_{ij} \times X_{ij} \qquad \forall i \in F, \forall j \qquad (8a)$$
$$f_i \geq l_i \qquad \forall i \in NF \qquad (8b)$$
$$f_i \geq l_i \; y_i \qquad \forall i \in NF \qquad (8c)$$

where l_{ij} (l_i) is the minimum annual capacity factor for i^{th} fossil fuel boiler (non-fossil fuel plant and hypothetical new boiler) and f_{ij} (f_i) is the corresponding annual capacity factor. The relationship between the annual capacity factor and electricity generation is given below:

$$E_{ij} = f_{ij} E_{ij}^{\max} \qquad \forall i \in F, \forall j \qquad (9a)$$
$$E_i = f_i E_i^{\max} \qquad \forall i \in NF \qquad (9b)$$
$$E_i = f_i E_i^{\max} y_i \qquad \forall i \in P^{new} \qquad (9c)$$

where E_{ij}^{max} (E_i^{max}) is installed capacity of i^{th} fossil (non-fossil power plants/new hypothetical boilers).

h) Selection of CO_2 capture process to be installed in power plant i
Location for CO_2 capture to put online on i^{th} existing coal-fired boilers will be determined. This constraint only applies to the case of carbon capture retrofit on existing coal-fired power plants.

$$\sum_k z_{ik} \leq 1 \qquad \forall i \in F^c \qquad (10)$$

i) If the existing coal-fired boilers shut down, no capture process will put online

$$z_{ik} \leq \sum_j X_{ij} \qquad \forall i \in F^c \qquad (11)$$

This constraint is associated to constraints (7a) which indicates that, the i^{th} fossil fuel boilers will be shut down if the binary variable (fuel selection variable), X_{ij}, is equal to 0. The above constraints are to ensure that no capture process will be put online if the coal-fired boilers are shut down.

j) Selection of hypothetical new power plants
In this study, six types of technology have been considered to supply supplemental energy for capture process as well as to meet growth rate demand. These technologies are: supercritical pulverized coal (PC), supercritical pulverized coal with capture (PC+CCS), Integrated gas combined cycle (IGCC), Integrated gas combined cycle with capture (IGCC+CCS), Natural gas combined cycle (NGCC) and natural gas combined cycle with capture (NGCC+CCS) Three different boilers performance and sizes for each technology has been incorporated in the model.

$$\sum_i y_i \leq b \qquad \forall i \in P^{new} \qquad (12)$$

where b is the number of boilers of new technology that will be incorporated in the model.

k) Selection of CO_2 sequestration location

For identical coal-fired boilers
This constraint is to ensure that only one sequestration site will be selected for one identical coal-fired boiler.

$$\sum_s w_{is} \le 1 \qquad \forall i \in F^c \cup P^{PCcap} \cup P^{IGcap} \cup P^{NGcap} \qquad (13a)$$

For coal-fired stations
Only one sequestration location will be selected for one coal-fired stations and new power plants with capture that consist of several identical boilers

$$w_{is} + w_{i's'} \le 1 \qquad \forall i \in F^g \cup P^{new}, \forall s, i' \ne i, s' \ne s \qquad (13b)$$

where w_{is} is a binary variable that indicates the selection of s^{th} potential location for CO_2 sequestration and F^g is coal-fired power plants that consists of several boilers.

l) <u>CO_2 sequestration must be determined once capture process is put online</u>
Once carbon capture retrofit is implemented in i^{th} existing coal fired boilers or new hypothetical boilers with capture process is constructed, s^{th} potential location for CO_2 sequestration is determined in order to store the CO_2 captured securely and permanently.

$$\sum_s w_{is} = \sum_k z_{ik} \qquad \forall i \in F^c \cup P^{PCcap} \cup P^{IGCCcap} \cup P^{NGCCcap} \qquad (14)$$

m) <u>Emission constraint/CO_2 balance:</u>
CO_2 emissions from all existing coal-fired boilers and new potential boilers, α_i (million tonne/yr) are defined as below:

$$\alpha_i = \sum_j CO_{2ij} E_{ij} \qquad \forall i \in F \qquad (15a)$$

$$\alpha_i = CO_{2i} E_i \qquad \forall i \in P^{new} \qquad (15b)$$

where CO_{2ij} is the CO_2 emission for the i^{th} existing fossil fuel boilers using the j^{th} fuel per electricity generated and CO_{2i} is CO_2 emission from new hypothetical boilers (tonne CO_2/MWh). CO_{2ij} and CO_{2i} is calculated using basic chemical equations that relate the production of CO_2 emission to the quantity and quality of fuel burned.

$$CO_{2ij} = 0.03667(EF)_{ij} \qquad \forall i \in F \qquad (16a)$$

$$CO_{2i} = 0.03667(EF)_i \qquad \forall\ i \in P^{new} \qquad (16b)$$

where 0.03667 is the conversion factor from coal to CO_2, EF_{ij} is the CO_2 emission factor of the i^{th} fossil fuel station using j^{th} fuel and EF_i is the CO_2 emission factor of the i^{th} potential new boilers as represents below:

$$EF_{ij} = \frac{1}{\eta_{ij}}\left(\frac{\%C}{HHV_{ij}}\right) \qquad (17a)$$

$$EF_i = \frac{(1-\varepsilon_{ik})}{\eta_i}\left(\frac{\%C}{HHV_{ij}}\right) \qquad (17b)$$

where η_{ij} is the efficiency of i^{th} fossil fuel boilers while operating on j^{th} fuel and η_i is the efficiency of potential new boilers. *%C* represents the percentage of carbon content and HHV_{ij} is the fuel higher heating value.

In constraints (15), CO_2 emissions from fossil power plants, α_i will be captured in k^{th} capture process also can be defined as $\alpha_i^{seq} + \alpha_i^{released}$, where α_i^{seq} is CO_2 captured by k^{th} capture process and $\alpha_i^{released}$ is CO_2 emitted to the atmosphere. For the case of CO_2 capture with k^{th} capture process, $z_{ik} = 1$ and ε_{ik} fraction of CO_2 captured,

$$\alpha_i^{released} = \alpha_i\left(1-\sum_k \varepsilon_{ik} z_{ik}\right) \qquad \forall i \in F^c \tag{18a}$$

$$\alpha_i^{seq} = \alpha_i \sum_k \varepsilon_{ik} z_{ik} \qquad \forall i \in F^c \tag{18b}$$

If there is no CO_2 capture exist, $z_{ik} = 0$**,** then all CO_2 emitted from the i^{th} fossil fuel boilers, α_i, will be released to the atmosphere, which results to:

$$\alpha_i^{released} = \alpha_i \qquad \forall i \in F^c \tag{19a}$$

$$\alpha_i^{seq} = 0 \qquad \forall i \in F^c \tag{19b}$$

Note that constraints (18a, 18b) and (19a, 19b) only apply to existing coal fired boilers. Besides CO_2 emission from existing fossil fuel boilers, the new hypothetical boilers e.g. PC, IGCC and NGCC with and without capture also contribute to the total CO_2 emissions. Thus, the total CO_2 emission (million tonne/year) from existing fossil fuel boilers and new hypothetical boilers can be written as:

$$\sum \alpha_i^{released} = \sum_{i \in F} \alpha_i\left(1-\sum_k \varepsilon_{ik} z_{ik}\right) + \sum_{i \in P^{new}} CO_{2i} E_i \tag{20}$$

Substitution equation (16a) into equation (21) will result in the following equation:

$$\sum \alpha_i^{released} = \sum_{i \in F}\left[\left(\sum_j CO_{2ij} E_{ij}\right)\left(1-\sum_k \varepsilon_{ik} z_{ik}\right)\right] + \sum_{i \in P^{new}} CO_{2i} E_i \tag{21}$$

Annual total CO_2 emissions from all existing fossil fuel boilers and potential new boilers must satisfy a specific CO_2 reduction target, $\%CO_2$.

$$\sum_{i \in F}\left[\left(\sum_j CO_{2_{ij}} E_{ij}\right)\left(1-\sum_k \varepsilon_{ik} z_{ik}\right)\right] + \sum_{i \in P^{new}} CO_{2i} E_i \le (1-\%CO_2)CO_2 \tag{22}$$

In above the constraints, the nonlinearity is due to the multiplication of continuous variable E_{ij} and binary variable, z_{ik}. To linearize the non-linear term, 'exact linearization' method has been employed.

3.0 Case Study

3.1 Description of OPG Power Stations

Currently, OPG operates 79 electricity generating stations, 5 are coal fired generating stations, C($i=1$-5), 1 is a natural gas generating station, NG($i=6$), 3 are nuclear generating stations, N($i=7$-9), 69 are hydroelectric generating station, H ($i=10$-78), and 1 is a small wind turbine, A($i=79$). At nominal levels, OPG generates about 115.8 TWh. and injects it 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 million tonnes of CO_2 was emitted in 2002, mainly from fossil fuel power plants. There are 27 fossil fuel boilers at the 6 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 Thunder Bay has 2 boilers (TB1-TB2). Currently, 4 (out of 8) boilers operated by Lennox are running on natural gas and the other 4 boilers are running on coal.

The operating cost for nuclear, hydroelectric, and wind turbine was estimated to be US$21/MWh, US$3.30/MWh, and US$2.70/MWh, respectively. Note that, currently, natural gas is the most expensive fuel used by OPG which is US$47/MWh (OPG, 2002). Since the main objective of this paper is to study CO_2 emission reduction through fuel balancing, fuel switching and CO2 capture, no attempt is 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%.

Index *i* (*i=1~79*) represents all of OPG's power plants. The index *j* (*j=1~2*) represents the fuel selection, j = *1(coal), 2(natural gas)*. The retrofit cost was estimated to be US$20 million/1000 MW with a 30 year lifetime and 15% annual interest rate. The reserve margin, r_i for load distribution for all OPG's fleet power plants is set at 1% higher than current operational level due to the design constraints and the lower bound was set to be 10%. In other words, the plants have to operate at least with 10% annual capacity factor; otherwise the plants will be shut down. A summary of OPG's current fossil fuel generating stations is contained in Table 1.

Table 1 Ontario Power Generation fossil fuel power stations

Station	Fuel	Heat rate (GJ/MWh)	Installed Capacity (MW)	Number of units	Annual capacity factor	Operational cost ($/MWh)	CO_2 emission (tonne/MWh)
Nanticoke 1 (N1)	Coal	9.88	500	2	0.75	20	0.93
Nanticoke2 (N2)	Coal	9.88	500	6	0.61	20	0.93
Lambton1 (L1)	Coal	9.84	500	2	0.5	22	0.94
Lambton2 (L2)	Coal	9.84	500	2	0.75	17	0.94
Lakeview (LV)	Coal	10.8	142	8	0.25	23	0.98
Lennox (LN)	NG	7.82	535	4	0.15	47	0.65
Thunder Bay (TB)	Coal	11.7	155	2	0.55	20	1.03
Atikokan (A)	Coal	9.82	215	1	0.44	20	1.03

According to Rubin et al. (2004), energy penalty associated with CO_2 capture process can be calculated using the following equation

$$EP = 1 - \frac{\eta CCS}{\eta ref} \qquad (23)$$

where *EP* is the energy penalty (fraction reduction in output), η_{CCS} and η_{ref} are the net efficiencies of the capture plant and reference plant respectively. This energy penalty also can be defined as the reduction in plant output for a constant fuel input and called "plant derating". For the case of CCS retrofit on existing coal-fired power plant, the energy penalty was assumed at 22% as suggested by Rubin et al. (2002). The detailed of existing coal fired stations with and without capture characteristics are shown in Table 2. 'ref' is represents existing coal fired power plant characteristics, whereas 'cap' represents the plant performance once CCS is incorporated. New state-of-the-art PC, IGCC and NGCC with and without capture cost estimation for different sizes are adjusted to the same economic references, which is described in Table 3.

In this study, the performances of power plant were obtained from the literature (Rubin, 2004; Ordorica et al., 2004; McDaniel, 2002; Parson 1998). Data for new supercritical PC power plants without capture at two different capacities (500 MW, 575 MW) and with capture at three different capacities (500 MW, 670 MW, 710 MW with 90% CO_2 capture) were obtained from Rubin et al. (2004) reported in 2001$US. On the other hand, plant performance and cost (mid 2001US$) for a 250 MW IGCC was gathered from real plant data (McDaniel, 2002). Two different plant designs and cost estimation of IGCC with capture (500 MW with 80% CO_2

capture and 513 MW IGCC with 60% CO_2 capture) were based on a study by Ordorica et al.

Table 2 Parameters and cost comparison of retrofit CO_2 capture on existing coal fired power plants

Parameters	N1		N2		L1		L2		LV		TB		A	
	ref	cap	ref	cap	ref	cap	ref	cap	ref	cap	ref	cap	ref	cap
Gross capacity (MW)	512	512	512	512	515	515	515	515	150	150	163	163	230	230
Net power gen. (MW)	490	382	490	382	493	385	493	385	142	111	155	120	215	168
Heat rate, HHV (GJ/MWh)	9.88	12.7	9.88	12.7	9.84	12.6	9.84	13.1	10.8	13.8	9.82	12.5	9.82	12.5
Capacity factor, ACF	0.75	0.75	0.61	0.61	0.5	0.5	0.75	0.75	0.25	0.25	0.55	0.55	0.44	0.44
CO_2 capture (%)	-	90	-	90	-	90	-	90	-	90	-	90	-	90
CO_2 emission (tonne/MWh)	0.93	0.09	0.93	0.09	0.94	0.09	0.94	0.09	0.98	0.09	1.02	0.11	1.02	0.11
CO_2 capital cost (M$)[a]	-	236	-	236	-	238	-	270	-	290	-	86	-	121
O&M cost ($/MWh)[a]	20	13.9	20	13.9	22	13.9	17	13.9	23	13.9	20.0	13.9	20.0	13.9
COE (¢/KWh)[a]	2.0	4.01	2.0	4.27	2.2	4.55	1.7	4.16	2.3	8.0	2.0	5.11	2.0	5.75
Capture cost ($/tonne CO2 avoided)[a]	-	24.0	-	27.1	-	26.6	-	27.1	-	64.5	-	33.8	-	40.7

[a] Cost is adjusted according to standard methodology and reported in 2004 US$ using Chemical Engineering Plant Cost Indexes (Chemical Engineering Magazine, 1990-2004) with coal price is US$1.2/GJ

Table 3 Specification of economic parameters (All cost are in 2004 USD)

Economic life time	30 year
Interest rate of return	15%
Fuel cost	
Coal	US$1.2/GJ
Natural gas	US$4.0/GJ

(2004). Plant performance for NGCC without capture of two different plant sizes (326 MW, 395 MW) were obtained from Parson (1998) and for 517 MW from Rubin et al. (2004). Plant characteristics for two different sizes of NGCC with capture (517 MW and 750 MW with 90% CO_2 capture) were obtained from Rubin (2004) and Bechtel (2002), respectively. Finally, cost of all proposed new power plants were adjusted with the same economic assumption and reported in 2004US$ using Chemical Engineering Plant Cost Indexes (Chemical Engineering Magazine, 1990-2004) with coal price of US$1.2/GJ and natural gas price of US$4/GJ.

4.0 Results

This section will discussed 2 main results: (1) The effect of cost of electricity (COE) by adjusting the CO_2 emission reduction by fuel balancing, fuel switching or capturing and (2) The effect of CO_2 reduction on distribution of electricity generation for existing and new plants for base load demand.

Figure 2 shows the effect of CO_2 reduction on COE. As can be seen, increasing the CO_2 emission reduction would result in increase in the cost of generating electricity. Currently, OPG electricity cost is 1.57¢/KWh which represents by 0% CO_2 reduction. The optimization results show that fuel balancing can contribute to the reduction of CO_2 emissions by only 3%. Fuel balancing also results in a reduction of cost of electricity to 1.54¢/KWh by reducing electricity generation from all four natural gas boilers by 32.1% and two coal fired boilers by 33.4% and 59.4%, respectively. The electricity generation from other fossil fuel boilers and non fossil fuel power plants were increased by 1% above the nominal operational level to maintain the electricity to the grid.

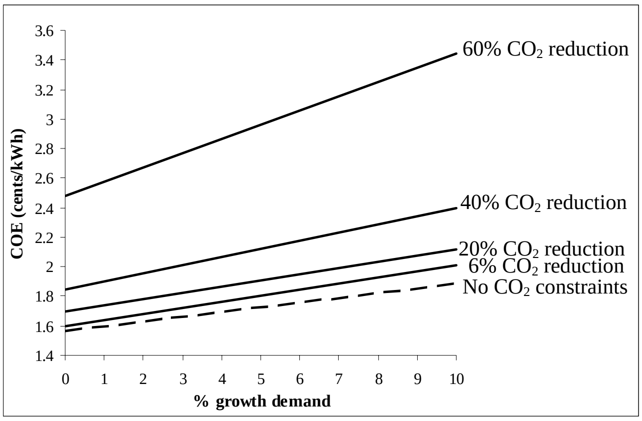

Figure 2 Effect of CO_2 reduction to the COE

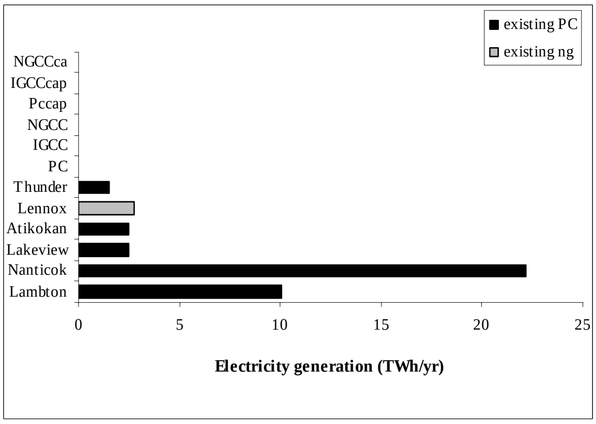

Figure 3 Current OPG's fossil-fuel electricity generation by plants in 2002

However, if CO_2 emissions are to be reduced beyond than 3% (e.g. 20% for Canada Kyoto Target), more stringent measures that include fuel switching, plant retrofitting and CO_2 capture will have to be employed. The optimization results show electricity generation from one natural gas boilers (LN4) need to be reduced by 32.1%, one natural gas boiler (LN2) reduced by 4.1% and nine coal fired boilers (L1,L2,N1,N2, N3, N4,LV7,LV8,TB1) need to be switched to natural gas resulting in an increase of cost of electricity of about 7.1%. Finally, the other coal fired boilers and non-fossil fuel power plants increase the electricity generation by 1% higher than the nominal operational level to meet the electricity demand. For the case of 60% CO_2 reduction, cost of electricity is increased by 35.6% since 4 new natural gas boilers are put online to compensate with the reduction in electricity output due to implementation of CO_2 capture retrofit on five Nanticoke coal-fired boilers, shut down of all 8 Lakeview boilers, 2 Lambton boilers (L1, L2) and 2 Thunder Bay boilers (TB1, TB2) as well as to achieve greater CO_2 reduction.

Figure 3-8 illustrate the electricity distribution for base case, 3%, 6%, 20%, 40% and 60% CO_2 reduction target in order to meet current electricity demand. Figure 3 shows the base case which represents OPG's current operational level (2002).

Figure 4 shows the optimization results for the case of 3% CO_2 reduction. For this case, and as is clear from the figure, no fuel switching is needed. In other words, this objective can be obtained by only adjusting operation of current boilers e.g. increasing load from existing non fossil power plants and decreasing load from existing fossil power plants (fuel balancing). The results show that electricity generation from all four natural gas boilers has been reduced by 32.1%. The electricity generation from other fossil fuel boilers and non fossil fuel power plants were increased at 1% higher than the nominal operational level to maintain the electricity to the grid.

In order to achieve more than 3% CO_2 reduction (Figure 5), 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 in order 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 3 natural gas boilers (LN1, LN2 and LN3) need to be reduced by 32.1%, one natural gas boiler (LN4) reduced by 8.2%, 2 coal fired boiler (LV1 and LV2) reduced by 59.4% and 34.8% respectively and the other coal fired boilers and non-fossil fuel power plants increase the electricity generation by 1% higher than the nominal operational level. Finally, one Nanticoke boiler (N8) which is the largest coal-fired boilers for OPG need to be switched to natural gas.

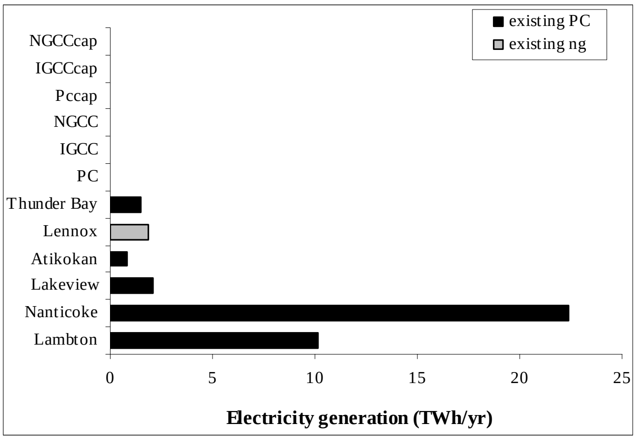

Figure 4 Optimal electricity generation for fossil fuel-plants & 3% CO_2 reduction

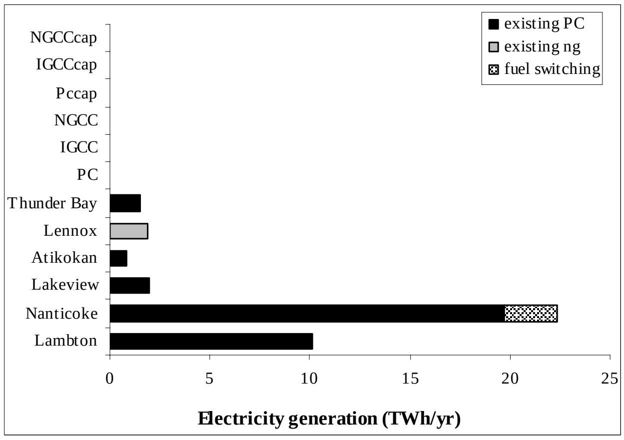

Figure 5 Optimal electricity generation for fossil fuel-plants & 6% CO_2 reduction

Figure 6 shows that, 20% CO_2 reduction and meet current electricity demand could be achieved by implementing fuel balancing and switching nine coal-fired boilers to natural gas**.** For the case of 40% CO_2 reduction as illustrated in Figure 7, the optimizer choose to switch most of coal fired boilers to natural gas and replacing all 8 Lakeview boilers with a new NGCC.

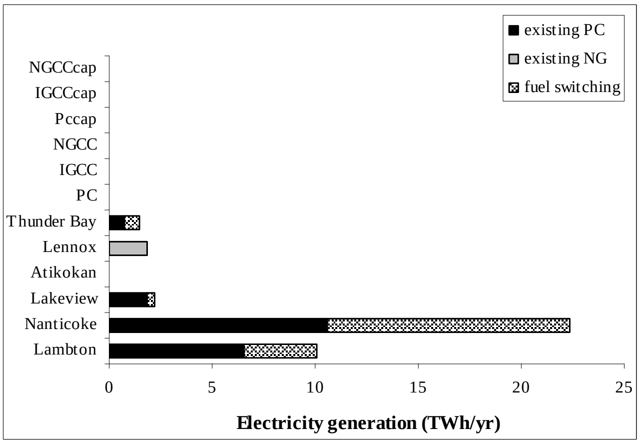

Figure 6 Optimal electricity generation for fossil fuel-plants & 20% CO_2 reduction

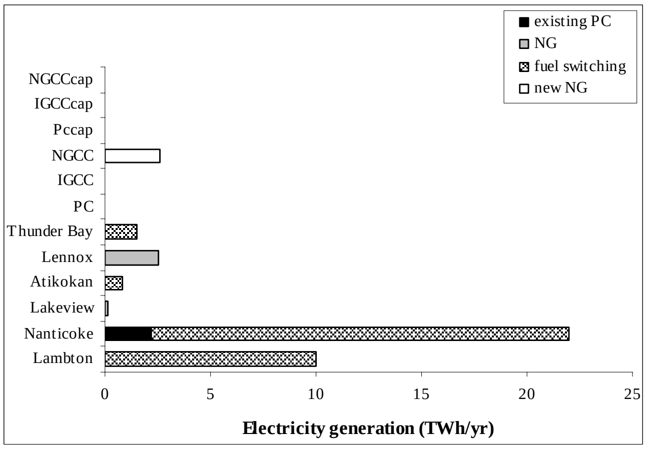

Figure 7 Optimal electricity generation for fossil fuel-plants & 40% CO_2 reduction

In order to achieve greater CO_2 emission reduction (e.g. 60% CO_2 reduction) and generating current electricity generation, the optimizer choose to implement CO_2 capture on five existing Nanticoke boiler (N1, N2, N3, N4, N5) and put on stream four new NGCC (two 326 MW, one 395 MW, one 517 MW) resulting in a COE of 2.44¢/kWh.

5.0 Conclusions

In this study, the model is formulated as Mixed Integer Non Linear Programme (MINLP) and implemented in GAMS (General Algebraic Modeling System). Exact linearization techniques were

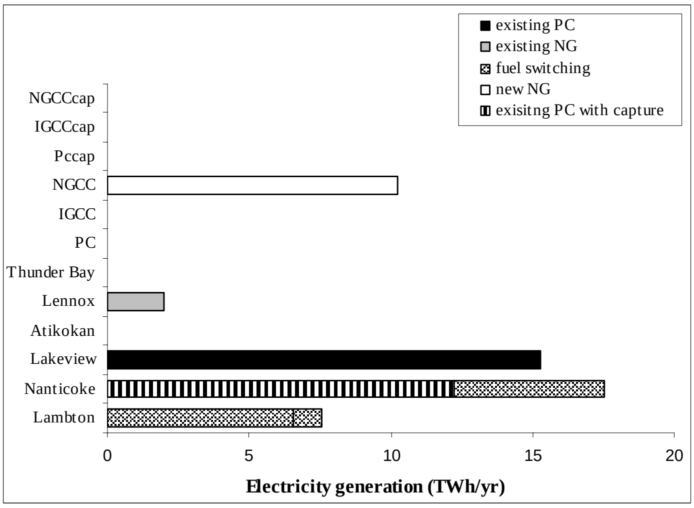

Figure 8 Optimal electricity generation for fossil fuel-plants & 60% CO_2 reduction

employed to facilitate solution development. The computer programme is capable of determining the best mix of fuel, annual capacity factor for existing power plants, location and size of CO_2 capture process and finally, construction of new state-of-the-art power plants, such as supercritical pulverized coal (PC), integrated gas combined cycle (IGCC) or natural gas combined cycle (NGCC) with and without CO_2 capture. As can be seen, increasing CO_2 reduction target leads to switching of more coal-fired boilers to natural gas. For a greater CO_2 reduction target, new plants with and without CCS will compete with existing plant that have been paid off but remain competitive due to lower overall cost. Among the option, NGCC is more favorable although average coal prices are projected to fall throughout the forecast due to lower capital costs, higher fuel efficiency and lower CO_2 emissions.

Optimization results for maintaining current electricity demand shows that fuel balancing could contribute up to 3% CO_2 reduction by increasing all non fossil fuel power plants by 1% above the nominal operation level, while reducing electricity generation from all four natural gas boilers (the most expensive fuel) by 32.1%. To meet the electricity demand, the optimization suggests then to increase all coal power plants by 1% above the nominal annual capacity factor. This result in a decrease of COE by 1.9% compare to the current situation (1.57¢/kWh). However if CO_2 emissions are to be reduced by more than 3%, more stringent measures that include fuel switching and retrofitting carbon capture on existing coal-fired boilers have to be employed. For instance, to achieve 6% CO_2 reduction (Canada's Kyoto target), the largest coal fired boilers, Nanticoke (N2), need to be switch to natural gas. In addition, electricity generation from all four existing natural gas boilers is reduced by 32.1%. Finally, electricity generation from the other coal-fired boilers and non fossil fuel power plants need to be increased by 1% higher than nominal operational level. For this scenario, COE is the same as the base case without optimization, which is 1.57¢/KWh. In order to achieve greater CO_2 emission reduction (e.g. 60% CO_2 reduction) and generating current electricity generation, the optimizer choose to implement a CO_2 capture on five existing Nanticoke boiler (N1, N2, N3, N4, N5) and put on stream four new NGCC (two 326 MW, one 395 MW, one 517 MW) resulting in an increase of COE by 35.6%. The optimiser also recommended to store the captured CO_2 in Lake Erie.

Acknowledgements

The authors wish to thank Ontario Power Generation (OPG) for their technical support towards this opportunity to contribute to the academic study of CO_2 capture. The information expressed herein is that of the authors and OPG takes no position on CO_2 capture and is simply furthering scientific endeavours.

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