

# Assessing CO<sub>2</sub> Mitigation Options Utilizing Detailed Electricity Characteristics and Including Renewable Generation

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**Abstract.** This paper presents a novel techno-economic optimization model for assessing the effectiveness of CO<sub>2</sub> mitigation options for the electricity generation sub-sector that includes renewable energy generation. The optimization problem was formulated as a MINLP model using the GAMS modeling system. The model seeks the minimization of the power generation costs under CO<sub>2</sub> emission constraints by dispatching power from low CO<sub>2</sub> emission-intensity units. The model considers the detailed operation of the electricity system to effectively assess the performance of GHG mitigation strategies and integrates load balancing, carbon capture and carbon taxes as methods for reducing CO<sub>2</sub> emissions. Two case studies are discussed to analyze the benefits and challenges of the CO<sub>2</sub> reduction methods in the electricity system. The proposed mitigations options would not only benefit the environment, but they will as well improve the marginal cost of producing energy which represents an advantage for stakeholders.

## 1. Introduction

The utilization of carbon-based fuels as energy sources significantly contributes to the production of pollutant gases. The accumulation of these gases in the atmosphere eventually leads to global warming. Global warming is defined as the rise of the earth's temperature due to anthropogenic greenhouse gas emissions (GHG) [1]. In the case of electricity systems, the energy sources varies amongst renewable (e.g., hydroelectric), nuclear, and fossil-based sources (e.g., oil, coal, natural gas) [2]. Each country or region has its own electricity system, whose operation is managed by a central authority with the objective of satisfying the seasonal electricity demand. According to the National Inventory Report 1990-2012 [3], the electricity sector accounted for 12% of Canada's GHG emissions in 2012.

Several strategies have been proposed in the literature to reduce pollutant gases emitted by the electricity sector. Since CO<sub>2</sub> emissions are one of the most harmful pollutants, the aforementioned strategies have focused on developing potential CO<sub>2</sub> mitigation methods and estimating the methods effectiveness. Accordingly, there are two methodologies used for such purpose: the techno-economic assessment of individual plants, and the medium-to long-term electricity system planning. The first methodology entails calculating a performance metric for each mitigation action; the better the value of the metric the better the mitigation strategy. This methodology includes two important techno-economic approaches. The first consists of calculating the associated cost of CO<sub>2</sub> capture (CCC); while the second calculates the cost of CO<sub>2</sub> avoided (CCA). The latter refers to the CO<sub>2</sub> emissions that



are actually mitigated as a result of the mitigation action. Based on Mariz et al. [4] and Paitoon et al. [5] works, CCA is the preferred mean for the evaluation of CO<sub>2</sub> mitigation strategies since it estimates the average unit cost of CO<sub>2</sub> reductions, while still affording one unit of electricity to consumers [6]. Moreover, Guillermo Ordorica-Garcia [7], Rao and Rubin [8], David Singh [9], and Akimoto et al. [10] have arrived at similar findings.

On the other hand, the second method identifies the investments that will best satisfy electricity demand and other system constraints over a given planning horizon. The models used for this purpose are extended with CO<sub>2</sub> mitigation strategies and CO<sub>2</sub> emission constraints (or, equivalently, a CO<sub>2</sub> tax). The greater the activity of a mitigation technology in the optimal solution, the better the mitigation strategy. For instance, Turvey and Anderson [11], Johnson and Keith's [12], Elkamel et al. [13], and Sparrow and Bowen [14] have contributed with valuable information regarding CO<sub>2</sub> mitigation in electricity system planning models. In addition, the International Energy Agency (IEA) has developed an economic model for long-term analysis of national and international energy markets named MARKAL (Market Allocation). Over the years, a 'Canadian' version of MARKAL, Extended-MARKAL, has been further developed in order to enhance its accuracy and features. For instance, the Extended-MARKAL version consider multi-regional contributions [15]-[18], multi-pollutant emissions calculations [18], stochastic assessments [19], accommodation of price elasticity of demands [20], and accommodation of international trade in CO<sub>2</sub> emission permits [21].

Based on the above discussions, previous studies undertaking techno-economic assessments of CO<sub>2</sub> mitigation options have generally disregarded the detailed operating characteristics of the electricity system. The aforementioned works have made generic assumptions on the performance of the generating units with scarce or no validation of parameters such as: capacity factor, unit heat rate, and fraction of CO<sub>2</sub> captured. This study presents a novel approach to understand the impact of CO<sub>2</sub> mitigation strategies in the electricity generation sub-sector. The following CO<sub>2</sub> mitigation strategies are applied: load balancing with the 'top down' approach, carbon tax regulations, fixed and flexible carbon capture and storage (CCS) methods. The latter is defined as the reunion of technologies and techniques that enables the capture of carbon dioxide (CO<sub>2</sub>) emissions produced from the combustion of fossil fuels in the industrial sector to reduce CO<sub>2</sub> emissions [22]. Accordingly, an electricity modeling framework is developed. The framework comprises detailed information of the electricity system's operation. The developed electricity system framework is based on deregulated power networks including markets for both real and reserve power. The consumers are price-insensitive, and its generators bid their units' power at the marginal generation costs. The electricity system operator provides hourly dispatch instructions seeking to maximize social welfare while respecting the physical constraints of the units and transmission system. There are three phases in the electricity system modeling: pre-dispatch, real time operation and market settlement. Each phase entails solving an optimization problem. The first phase involves a dynamic optimization problem whereas the remaining phases are fed by the first phase dynamic results. The optimization model proposed in this work uses the IEEE RTS '96 (IEEE One-Area Reliability Test System – 1996) [23] as test case. Therefore, the performance of the electricity system is benchmarked with GHG regulations in the form of a carbon tax at \$15, \$40 and \$100/tonne CO<sub>2</sub>. Additionally, two different CO<sub>2</sub> capture methods are included in the electricity system (i.e., fixed and flexible CO<sub>2</sub> capture), and their impacts are assessed on the entire electric system. To the author knowledge, this approach has not yet been considered in any techno-economic or electricity system planning study.

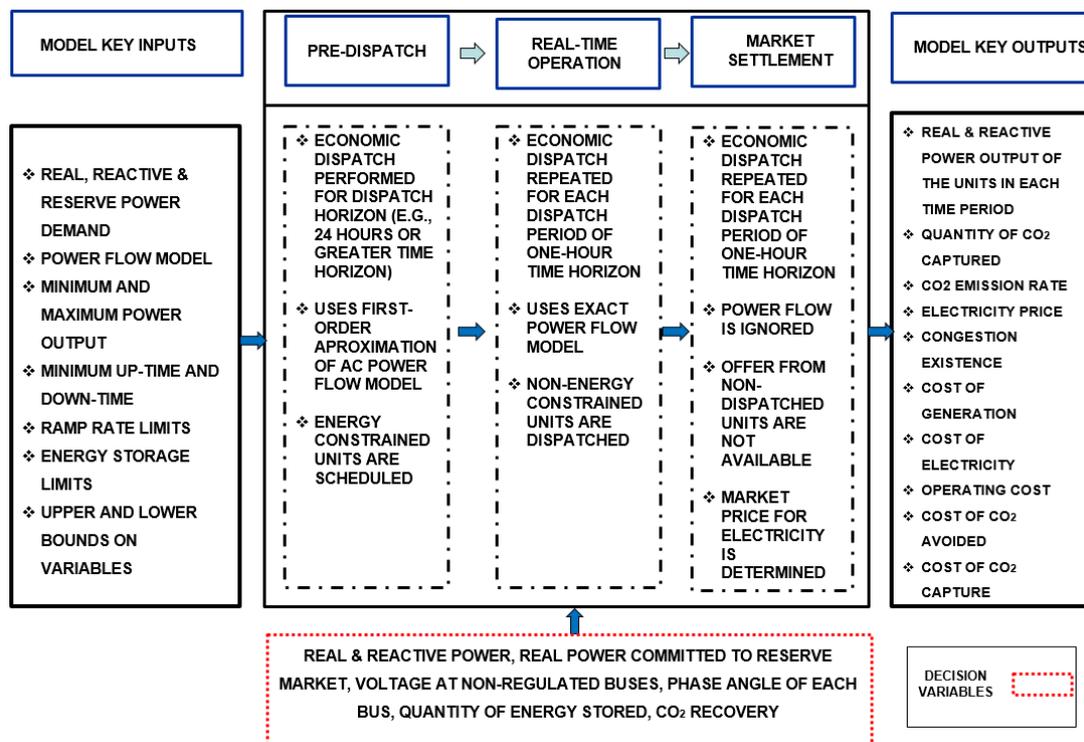
## 2. Problem statement

In this work, an electricity system model is developed based on Ontario's electricity system operation. Parameters describing the technical and economic performance of Ontario's electricity system generating units were not readily available, whereby the IEEE RST '96 (IEEE One-Area Reliability Test System–96) was selected as test case. The IEEE RST '96 system features several appropriate characteristics for this case study. Such characteristics include: physical properties of the transmission system, electricity supply provided by large centralized and dispatchable generating units; and primary energy source (i.e., fossil fuels, uranium, or moving water). Additionally, the IEEE RST '96 have served as reference case for numerous electricity system studies; which is an advantage when

validating information [24],[25]. Simulating an electricity system involves solving both a loadflow problem and an economic dispatch problem. The loadflow problem determines possible power flow losses within transmission and distribution lines. At this stage, the net power injected at each bus reflects the electricity demand for a single moment in time, and a particular response of the generating units in the system to that demand. The economic dispatch problem identifies the optimum output level of the generators that satisfy the electricity demand, while meeting technical and operational requirements. In this work, the electricity system is studied with reference to its three main phases: pre-dispatch, real-time operation, and market settlement. Additionally, the consumers are price *insensitive* and do not submit offers to buy electricity. In other words, the price depends only on the electricity demand which is, as per the price-insensitive assumption, referred as to *inelastic*.

### 3. Model formulation

This section presents a summary of an optimization model with the aim to build the three primary phases of an electricity system model. Figure 1 shows the relationship between the three model optimization phases (e.g., pre-dispatch, real-time operation and market settlement) considering the key inputs and outputs, and also the parameters used to estimate the benefits and costs of the evaluated mitigation options.



**Figure1.** General layout of the electricity system simulator optimization model

#### 3.1. Phase 1: Pre-dispatch

The pre-dispatch phase targets to optimize the power availability and distribution in time within the electricity system model. This is accomplished by executing preliminary scheduling of the generating units well in advance. The electricity system operating and maintenance costs can be subdivided into two categories: fixed and variable. Given that fixed maintenance and operating costs do not vary as a function of the power output, the economic dispatch problem objective function ( $z$ ) can be simplified to:

$$z = \sum_{n \in NG} \int_0^{P_n^S} \left[ \left( \frac{dC_n^{VOM}}{dP_n^S} \right) \right] dP_n^S \quad (1)$$

Where the indices  $n$  and  $s$  represent the type of generating unit and the type of power supplied, respectively. The objective function is formulated as follows:

$$z = \sum_{n \in NG_D} \sum_{b=1}^{N_b} y_{bn} IHR_{bn} FC_n L_n + \sum_{r \in RM} C^{import} \cdot RM_r^{slack} \quad (2)$$

where  $N_b$  is the number of bids per generating unit,  $L_n$  is the time duration (in this work  $L_t$  is considered to be equal to 1 hour),  $y_{bn}$  is the quantity of bids accepted by a particular generating unit,  $RM_r^{slack}$  is the reserve power pertaining to the slack bus, and  $C^{import}$  is the cost of the electricity imported from outside the grid. In this work,  $C^{import}$  is set at a ten percent premium to the most expensive bid of any generator in the system. Likewise, the last term in the objective function represents the cost required to facilitate reserve power from outside of the electricity system.

The economic dispatch problem has been formulated as an MINLP problem that consists of 420 equations, 33 binary variables, 501 continuous variables, and 165 nonlinear constraints. The optimization problem was solved using the MINLP solver DICOPT [26] in the General Algebraic Modeling System (GAMS). At this point the objective function has been formulated only to solve the economic dispatch problem. Therefore, in order to transform it into a proper pre-dispatch objective function; a time index is added to the variables and dynamic constraints are incorporated in the equation. Additionally, it is imperative to provide ‘special’ dynamic equations; otherwise, the implicit assumption is that the electricity system is undergoing a *black-start* (i.e., recovering from a state in which all generation is shut-down). Since dynamic constraints have been added to the pre-dispatch problem, considering a black-start in the system may lead to infeasible solutions in this phase. Consequently, the following equation illustrates the final pre-dispatch objective function:

$$\min_{\eta} z = \sum_{t=1}^T \sum_{n \in NG} u_{nt} HI_n FC_n + \sum_{t=1}^T \sum_{n \in NG_D} \sum_{b=1}^{N_b} y_{bnt} IHR_{bnt} FC_n L_t + \sum_{t=1}^T \sum_{r \in RM} C^{import} \cdot RM_{rt}^{slack} \quad (3)$$

Where  $\eta$  represents the following set of decision variables

$$\eta = \left\{ u_{n,t}, y_{bn,t}, P_{n,t}, P_{n,t}^S, P_{n,r,t}^R, Q_{n,t}^S, P_{k,t}, Q_{k,t}, I_{k,t}^{Re}, I_{k,t}^{Im}, \theta_{k,t}, |V_{k,t}|, x_{n,t}^{on}, x_{n,t}^{off}, w_{n,t}, \right. \\ \left. X_{n,t}^{on}, \psi_{n,t}^{on}, X_{n,t}^{off}, \psi_{n,t}^{off}, P_{r,t}^R, \rho_{n,r,t}, E_{k,t}, RM_{r,t}^S, RM_{r,t}^{Slack} \right\} \quad (4)$$

The main difference between the economic dispatch and the pre-dispatch objective function consists of the unit start-up ( $u_{nt}$ ) which represents the energy input required by a thermal unit (that has been off) to initiate operations. Based on the previous definition, the unit’s variable maintenance and operating cost is now expressed in terms of the start-up and the fuel costs. To a first approximation, the start-up cost is the energy expenses (fuel) required to start-up a particular power unit, where  $HI_n$  represents the heat input required to cold-start a unit. The binary variable representing the unit start-up takes the value of one if the unit started-up in the time period; or zero otherwise. This can be expressed as follows:

$$u_{n,t} \geq \omega_{n,t-1} - \omega_{n,t} \quad \forall n \in NG, t \in T \quad (5)$$

In the case of units experiencing black-start (e.g., units with non-zero start-up cost), the unit start-up ( $u_{nt}$ ) is zero in the optimal solution, and for units whose start-up costs are zero the solution is indeterminate.

The capacity utilization is expressed in terms of the unit’s availability and capacity. The unit’s availability is the power that a generator can produce in a given time period; while the unit’s capacity

is the nominal power that the unit is designed to produce. The present constraint specifies that the capacity utilization ( $P_{n,t}$ ) of a unit  $n$  in a given time period  $t$  is equal to the sum of the bids accepted in the time period ( $y_{bn,t}$ ), i.e.

$$P_{n,t} = \sum_{b=1}^{Nb} y_{bn,t} \quad \forall n \in NG, t \in T \quad (6)$$

The capacity utilization of each unit in each time period must equal the sum of the unit's contribution to the real and reserve market in a given time period  $t$ :

$$P_{n,t} = P_{n,t}^S + \sum_{r \in RM}^{Nb} P_{n,r,t}^R \quad \forall n \in NG, t \in T \quad (7)$$

Where  $P_{n,t}^S$  is the power supplied to the real market and  $P_{n,r,t}^R$  is the power supplied to the reserve market.

Minimum and maximum real and reactive power outputs are represented by the following constraints:

$$(1-\omega_{n,t})P_n^{\min} \leq P_{n,t}^S \leq (1-\omega_{n,t})P_n^{\max} \quad \forall n \in NG, t \in T \quad (8)$$

$$(1-\omega_{n,t})Q_n^{\min} \leq Q_{n,t}^S \leq (1-\omega_{n,t})Q_n^{\max} \quad \forall n \in NG, t \in T \quad (9)$$

Where  $Q_{n,t}^S$  is the reactive power supplied to a generating unit  $n$  at a particular time  $t$ ,  $Q_n^{\max}$  and  $Q_n^{\min}$  are the maximum and minimum reactive power outputs, respectively. Additionally,  $\omega_{n,t}$  is a binary variable used to illustrate the state of a generating unit  $n$  in time period  $t$ . The binary variable assumes a value of one if the unit is "off", and zero otherwise.

There are generating units within the electricity system that are constrained not only in terms of power output, but also in terms of energy output. One example of energy constrained units are the hydroelectric generating units. These units cannot generate more power than that produced by the water contained in its reservoir. This is expressed as follows:

$$E_{k,t} = E_{k,t-1} + \left( \dot{E}_{k,t} - \sum_{n \in NG_k} P_{k,n,t}^S \right) L_t \quad \forall k \in N^{ST}, t \in T \quad (10)$$

$$P_{k,t} L_t \leq E_{k,t} \quad (11)$$

Where  $E_{k,t}$  is the electric energy in a particular bus  $k$  at a particular time  $t$ , and  $\dot{E}$  represents the energy inflow rate. Equation (10) defines the available energy, and outlines the net additions in each time period  $t$ . Also, it defines the energy availability at time period  $t-1$ . On the other hand, the unit's output limit can be calculated using Equation (11). At this point, the electricity system is started one day in advance (of the actual initial period of interest) to avoid any black-start that could turn the problem's solution into infeasible. To avoid anomalies in the results during the period of interest, the initial pre-dispatch period occurs over a 48-hour period.

The net real power injected at each bus ( $P_{k,t}$ ) is the difference between the total output from a generating unit ( $P_{nt}^S$ ) and the local demand ( $P_{kt}^D$ ). The same situation applies to the reactive power ( $Q_{kt}$ ), except for the buses with shunt admittance to ground (given the buses extra reactive power).

The net power available at each bus can be calculated as:

$$P_{k,t} = \sum_{n \in NG_k} (P_{nt}^S) - (P_{kt}^D) \quad \forall k \in N, t \in T \quad (12)$$

$$Q_{kt} = \begin{cases} \sum_{n \in N_k} Q_{nt}^S - Q_{kt}^D & \forall k \notin N^{shunt} \\ \sum_{n \in N_k} Q_{nt}^S - Q_{kt}^D + |V_{kt}|^2 & \forall k \in N^{shunt} \end{cases} \quad \forall t \in T \quad (13)$$

In modern electricity systems reliability is important. Therefore, from the pool of available capacity, a portion is selected for a back-up role. The reserve requirements used in this study are based on the Ontario's electricity system operation; which adhered to the NERC (North American Electricity Reliability Corporation) [27]. Reserves are required to preserve the generation/load balance, as well as to compensate for the variability and uncertainty of load (e.g., regulation, load following, and forecast uncertainty). Also, reserves respond to forced outages of conventional generation (contingency reserves). The reserve power requirements ( $P_{n,r}^R$ ) are represented by the load of operating capacity exclusively committed to the reserve market. In the present work, three reserve markets are considered and the total power committed to each is expressed as follows:

- Ten-minute spinning reserve:

$$RM_{10^{sp}}^S = \sum_{n \in NG} P_{n,10^{sp}}^R (1 - \omega_n) \quad (14)$$

- Ten-minute non-spinning reserves:

$$RM_{10^{ns}}^S = RM_{10^{sp}}^S + \sum_{n \in NG, \tau_n^{sp}=0} \omega_n P_{n,10^{ns}}^R \quad (15)$$

- 30-minute non-spinning reserve:

$$RM_{30}^S = RM_{10^{ns}}^S + \sum_{n \in NG} P_{n,30}^R (1 - \omega_n) + \sum_{n \in NG, \tau_n^{sp}=0} \omega_n P_{n,30}^R \quad (16)$$

Where  $RM_r^S$  represents the power supplied to the reserve market.

### 3.2. Phase 2: Real-time operation

In an active power network, the system operator is constantly updating the demand forecast since this can change at any given time. Therefore, generating units require constant changes in their power output to regulate voltage, and respond to contingencies in an economical and optimal way. The real-time operation phase can be described as a simplified pre-dispatch phase problem. Though, there are small differences between the two phases in terms of the actual demand, generator outputs, and power flows. For instance, real-time operation is no longer a dynamic problem; nevertheless, time dependency is preserved. The state of time-dependent variables is specified using parameters whose values are obtained from the solution of the problem for the previous time period. The problem used in the real-time operation phase considers the economic dispatch problem for a single time period. As a result, the objective function is formulated as follows:

$$\min_{\eta} z = \sum_{n \in NG} u_n HI_n FC_n + \sum_{n \in NG_D} \sum_{b=1}^{N_b} y_{b,n} IHR_{b,n} FC_n L_t \frac{1}{10^3} + \sum_{r \in RM} C^{import} \cdot RM_r^{slack} \quad (17)$$

$$\eta = \{u_n, y_{b,n}, P_n, P_n^S, P_{n,r}^R, Q_n^S, P_k, Q_k, I_k^{Re}, I_k^{Im}, \theta_k, |V_k|, x_n^{on}, x_n^{off}, w_n, RM_r^S, RM_r^{slack}\}$$

Since time has been removed from the objective function, the real-time operation phase is now a deterministic problem; which requires less computational effort. Additionally, the definitions that were previously discussed in the pre-dispatch phase regarding the generating unit constraints, minimum and maximum power output, and reserve power constraints are also used for the real-time operation.

Furthermore, the real-time operation phase requires no power flow model simplification. During this phase, the actual performance of the electricity system is described, which means it is crucial to use the complete power flow model as shown below:

$$P_k^S = I_k^{\text{Re}} |V_k| \cos \theta_k + I_k^{\text{Im}} |V_k| \sin \theta_k \quad \forall k \in N \quad (18)$$

$$Q_k^S = I_k^{\text{Re}} |V_k| \sin \theta_k - I_k^{\text{Im}} |V_k| \cos \theta_k \quad \forall k \in N \quad (19)$$

In the present electricity system, one of the main goals of the pre-dispatch phase is to determine a plan for using energy constrained units (e.g., hydroelectric generating units). Unlike other generating units in the IEEE RTS' 96 system, the hydroelectric units have a minimum real power output of zero. Thus, it is possible to find hydroelectric units that have zero real power output and non-zero reactive power output. This situation is tolerated during the pre-dispatch phase, and such results are used to initialize the real and reactive power in the real-time operation phase. As a result,  $Q_n^S$  is fixed at zero for any hydroelectric unit where  $P_n^S = 0$ .

### 3.3. Phase 3: Market settlement

The power flow model is removed from the market settlement. This leads to the assumption that the generating units and loads are connected to the same bus. Since the power flow model is ignored, the references (i.e., variables and constraints) related to this model such as:  $I_k^{\text{Re}}, I_k^{\text{Im}}, \theta_k, |V_k|$  are also ignored. Moreover, references related to the reactive power such as  $Q_n^S$  and  $Q_k$  are eliminated, as well as the minimum and maximum reactive power output. Accordingly, the market settlement objective function is formulated using the same structure applied in the real-time operation. However, since the power flow is ignored at this stage, the decision variables set is rewritten as follows:

$$\eta = \{u_n, y_{b,n}, P_n, P_n^S, P_{n,r}^R, x_n^{\text{on}}, x_n^{\text{off}}, RM_r^S, RM_r^{\text{Slack}}\} \quad (20)$$

Correspondingly, some of the definitions previously discussed on capacity utilization (6), power disaggregation between real and reserve market (7), and reserve power in the electricity system (14)-(16) are calculated following the real-time operation phase structure. Additionally, based on the assumption that all the generating units and loads are connected to a single bus, the net power available at each bus switch into the supply/demand balance. This can be formulated as follows:

$$\sum_{n \in NG} P_n^S \geq \sum_{k \in N} P_k^D \quad (21)$$

In order to ensure the availability of reactive power in the system, the following constraint is added:

$$\sum_{n \in NG} Q_n^{\text{max}} (1 - \omega_n) \geq \sum_{k \in N} Q_k^D \quad (22)$$

## 4. CO<sub>2</sub> mitigation options assessment techniques

In order to evaluate the effectiveness of a particular mitigation strategy, it is important to account for the CO<sub>2</sub> emissions that are in fact mitigated as a result of a particular mitigation action. In this work, calculating the cost of CO<sub>2</sub> avoided (CCA) is considered the most reliable method for this matter. This is formulated as follows:

$$CCA = \frac{(CoE) - (CoE)_{ref}}{(CEI)_{ref} - (CEI)} \quad (23)$$

where  $CoE$  represents the cost of electricity, and  $CEI$  is the CO<sub>2</sub> emission intensity. Accordingly, by definition  $CCA$  is the ratio of the incremental cost of the CO<sub>2</sub> mitigation action to the incremental change in CO<sub>2</sub> emissions. The values for  $CoE$  and  $CEI$  can be calculated as follows:

$$CoE = \frac{\sum_{n \in NG} \dot{C}_n^{FOM} P_n^{\text{max}}}{HPY \sum_{n \in NG} CF_n P_n^{\text{max}}} + \frac{\sum_{n \in NG} FC_n HR_n CF_n P_n^{\text{max}} L}{\sum_{n \in NG} CF_n P_n^{\text{max}}} \quad (24)$$

$$CEI = \frac{\sum_{n \in NG} HR_n EI_n^{CO_2} CF_n P_n^{max} L}{\sum_{n \in NG} CF_n P_n^{max}} \quad (25)$$

Where  $\dot{C}_n^{FOM}$  represents the annual fixed operating and maintenance costs,  $P_n^{max}$  indicates the maximum real power value,  $FC_n$  represents the fuel cost,  $HR_n$  is the heat rate,  $HPY$  denotes the annual operating time, and  $EI_n^{CO_2}$  represents the fuel emission intensity.

In this work, setting carbon tax prices is considered an accurate method for the assessment of CO<sub>2</sub> mitigation strategies. The emission cost can be expressed in terms of the heat input to boilers as follows:

$$CO_{n,t}^{CO_2} = u_{n,t} HI_n EI_n^{CO_2} TAX^{CO_2} + \dot{q}_{n,t} EI_n^{CO_2} TAX^{CO_2} L_t \quad (26)$$

Where  $TAX^{CO_2}$  is the CO<sub>2</sub> emission's tax and  $\dot{q}_{n,t}$  is the boiler's heat input. The first term of the equation accounts for the fuel consumed during the start-up, whereas the second term accounts for fuel consumed during normal operation. For that reason, it is convenient to express the permit cost in terms of the incremental heat rate. Consequently, the unit's variable operating and maintenance cost of a generating unit  $n$  at a time period  $t$  can be formulated as follows:

$$C_{n,t}^{VOM} = C_{n,t}^{start-up} + C_{n,t}^{fuel} + C_{n,t}^{CO_2} \quad (27)$$

Where  $C_{nt}^{CO_2}$  is the cost per unit of CO<sub>2</sub> that a generating unit emits.

The electricity system simulator is used to assess the effectiveness of the load balancing approach to reduce GHG emissions. Accordingly, the marginal emission cost is calculated taking the first derivative of the first term in Equation (26) with respect to  $P_{n,t}^S$ . Furthermore, in order to capture the relationship between carbon tax ( $TAX^{CO_2}$ ) and CO<sub>2</sub> emissions, a surrogate model is developed. Such surrogate model is a reduced order model that attempt to represent the solution space of the models they are based upon but with fewer variables. The development of such reduced-order mathematical model is used to represent the coal-fired electricity generating unit with CO<sub>2</sub> capture. Aspen Plus® was used as simulation tool to evaluate the coal-fired generating unit. This unit is modelled after the 500 MWe units at the Ontario power generation's (OPG) Nanticoke station in Ontario, Canada. These subcritical units are designed to burn subbituminous coal and to generate 1500 tonne per hour of steam at 538 °C and 165 bar with a single, 538 °C reheater. Therefore, the reduced-order model only needs to represent the Pareto optimal frontier of the power plant [28]. The unit's power plant process model can be found in Colin's [29].

On the other hand, approaches to capture CO<sub>2</sub> in coal-fired power units fall into one of three different categories: pre-combustion, oxy-fuel combustion, or post-combustion capture. Post-combustion capture (PCC) methods using amine (i.e., MEA) solvents and are regarded as the best near-term CCS option. Therefore, this approach is selected to develop an integrated model for a power plant with CO<sub>2</sub> capture [29]. A generating unit that captures CO<sub>2</sub> does not need to obtain permits for the fraction of CO<sub>2</sub> that has been captured assuming that it is all permanently stored. Hence, a new cost component is required to represent the rebate that generating units receive for the quantity of CO<sub>2</sub> captured. Also, it is assumed that the solvent consumption rate is proportional to the CO<sub>2</sub> capture rate.

## 5. Case studies

In this section, two case studies are analyzed considering two GHG mitigation strategies: load balancing, and carbon tax regulations. These case studies aim to evaluate the effectiveness of different mitigation strategies in the electricity generation sub-sector.

### 5.1. Case study 1: reducing GHG emissions through load balancing

The first case study discusses load balancing as GHG mitigation strategy. This strategy differs from others since it does not require new capital investment. Accordingly, the IEEE RTS '96 system was

used as test platform for this approach assessment. Moreover, detailed information on the power plants within the IEEE RTS '96 system is summarized in Table 1. The parameters used in this analysis are compiled in Table 2. The capacity factors are taken from the base-case simulation of the IEEE RTS 96', the annual cost ( $C_n^{FOM}$ ) and the rest of the parameters (e.g., fuel costs, net heat rates, incremental heat rates, cold start unit heat input) are taken from Grigg et al [23]

**Table 1.** Summary of generating units power output

Bus	Unit type		Number	$CF$	$HR_n$		$N^{start-up}$
	Fuel	Capacity $MWe$			Time-weighted $Btu/kWh$	Energy-weighted $Btu/kWh$	
Abel	#2 Fuel Oil	20	2	0.02	14821	14607	7
Abel	Coal	76	2	0.65	12475	12080	0
Adams	#2 Fuel Oil	20	2	0.05	14673	14592	10
Adams	Coal	76	2	0.7	12408	12064	0
Alder	#6 Fuel Oil	100	3	0.39	11465	10535	3
Arne	#6 Fuel Oil	197	3	0.28	9816	9696	16
Arthur	#6 Fuel Oil	12	5	0.02	16017	16017	25
Arthur	Coal	155	1	0.28	10951	10680	0
Asser	Coal	155	1	0.48	10428	9965	0
Astor	Nuclear	400	1	1	10000	10000	0
Attlee	Nuclear	400	1	1	10000	10000	0
Aubrey	Hydro	50	6	0.64	N/A	N/A	N/A
Austen	Coal	155	2	0.53	10197	9931	0
Austen	Coal	350	1	0.83	9508	9505	0

**Table 2.** Parameters of units at Austen, Arne and Alder in the reference case

Parameter	Reference-case values		
	Austen	Arne	Alder
$CF$	0.826	0.278	0.393
$HR_n$ ( $Btu/kWh$ )	9500	9600	10000
$C_n^{FOM}$ ( $\$/MW/year$ )	25000	7500	7500
$P_n^{max}$ ( $MWe$ )	350	591	300
$EI_n^{CO_2}$ ( $lb CO_2/MMBtu$ )	210	170	170
$FC_n$ ( $\$/MMBtu$ )	1.2	2.3	2.3

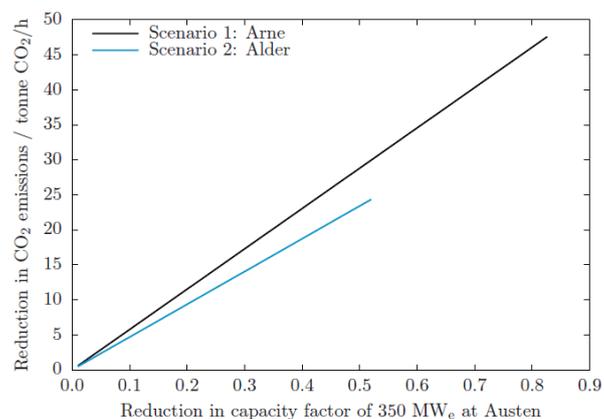
The final approach considers load shifting from Austen (350 MWe) to the units at Arne and Alder. In scenario 1, Arne load balancing is limited by the capacity of the 350 MWe unit at Austen. In this scenario, at maximum load balancing,  $CF_{Austen} = 0$  and  $CF_{Arne} = 0.767$ . On the other hand, in scenario 2, Alder load balancing is limited by the capacity of the 100 MWe units at Alder. In this scenario, at maximum load balancing,  $CF_{Austen} = 0.306$  and  $CF_{Arne} = 1.0$ . The estimated  $CoE$ ,  $CEI$ , and  $CCA$  for the two scenarios of interest are shown in Table 3. Concurrently, it is worth to recall that  $CCA$  is defined as the carbon price at which the mitigation action 'breaks even' with the reference case. Therefore, since the carbon price obtained exceeded the \$65/tonne  $CO_2$ , it would be economical to transfer load from Austen to Arne. This action would reduce  $CoE$  and achieve  $CO_2$  emission reductions of up to 48 tonne  $CO_2/h$ . As shown in Table 3, when load balancing is applied between

Austen and Alder, a carbon price exceeding \$87/tonne CO<sub>2</sub> is required to make this approach economically feasible. Thus, CO<sub>2</sub> emissions can be reduced up to 24 tonne CO<sub>2</sub>/h in relation to the reference case. It is important to keep in mind, that the overall rate of CO<sub>2</sub> emissions from the system is approximately 1000 tonne CO<sub>2</sub>/h.

**Table 3.** Cost of CO<sub>2</sub> avoided for load balancing scenarios

Parameter	Scenario 1		Scenario 2	
	Initial	Final	Initial	Final
CoE (\$/MWh <sub>e</sub> )	18.59	25.4	17.85	23.04
CEI (t CO <sub>2</sub> /MWh <sub>e</sub> )	0.845	0.74	0.866	0.806
CCA (\$/t CO <sub>2</sub> )		65		87
(ΔCO <sub>2</sub> ) <sup>max</sup> (t CO <sub>2</sub> /h)		48		24

These results indicate that load balancing could immediately trigger emission reductions. The basis used in the present analysis is representative of the basis employed in many published studies [13]; therefore, it is worth to consider its validity. For instance, the basis includes heat rate (HR) values corresponding to those of the generating units at base loads. Implicit in the above analysis is that the location of the units in relation to the reference case, and the loads in the system is unimportant. In other words, a unit of power injected at Alder or Arne is undifferentiated from a unit of power injected at Austen. This is further reinforced by the observation that there is limited unused capacity along the transmission lines that connects Alder to the rest of the system. Therefore, the transmission system may have implications on the effectiveness of load balancing that the previous analysis fails to capture. Other factors that denotes the validity of the basis, involves the 350 MWe unit at Austen (see Figure 2), and the units at Alder and Arne; which have an important role in satisfying the requirements for reserve power in the IEEE RST '96. This may limits the extent to which the load can be shifted from the 350 MWe unit at Austen to the units at Alder or Arne.

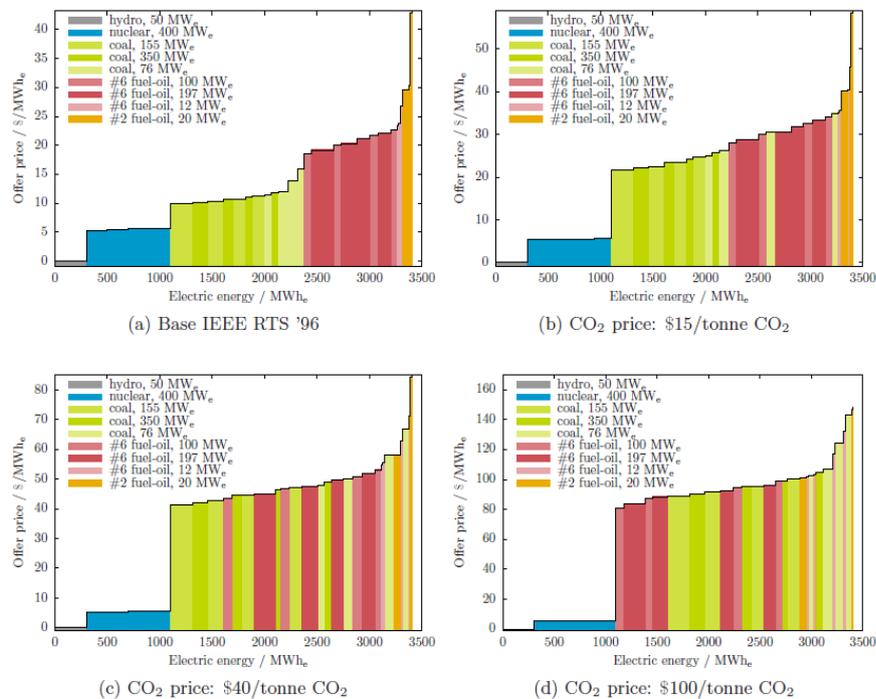


**Figure 2.** Effect of load balancing on CO<sub>2</sub> emission reductions.

### 5.2. Case study 2: Adding GHG regulation to the electricity system

This second case study discusses GHG regulations as the proposed mitigation strategy. Accordingly, generators are required to pay for every unit of CO<sub>2</sub> emitted to the atmosphere. This means that, in addition to the unit's variable operating and maintenance cost, there is now a contribution based upon the quantity of CO<sub>2</sub> that the unit emits. The unit's variable operating and maintenance cost is shown in (32). Figure 3 shows the composite supply curve for the IEEE RTS '96 for different levels of carbon prices. In the vertical axis, it is shown the electricity offer price (\$/MWh<sub>e</sub>); while the horizontal axis comprises the electric energy (MWh<sub>e</sub>). As can be seen in the figure, as the carbon price increases so

does the marginal cost of each bid and this increase takes place in a manner that is proportional with respect to the carbon price and unit's incremental heat rate. Consequently, bids from coal units are at the higher end of the composite supply curve and vice versa for bids from oil-fired units. Accordingly, for carbon prices greater than the maximum analyzed in this work (\$100/tonne CO<sub>2</sub>), the relative position of the units matches the one based merely on the CO<sub>2</sub> emission intensity.

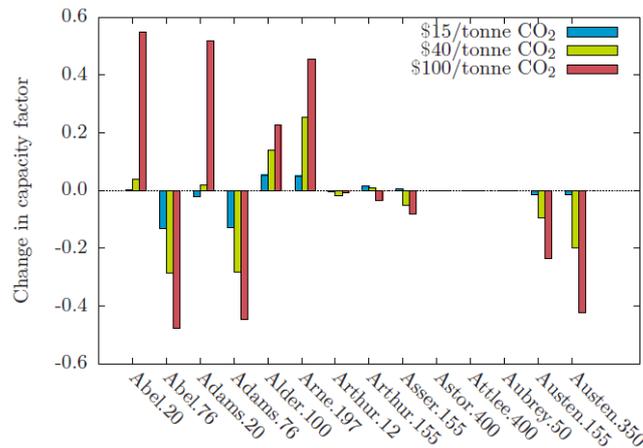


**Figure 3.** Composite supply curves for electricity system for different levels of carbon prices [30]

For the present case study, the power system is simulated for one full week under three different carbon prices: \$15/tonne CO<sub>2</sub>, \$40/tonne CO<sub>2</sub>, and \$100/tonne CO<sub>2</sub>. In fact, \$15/tonne CO<sub>2</sub> is the permit price proposed by the Canadian federal government. Such a permit price level is perceived as sufficient to stimulate CCS where CO<sub>2</sub> is an input to the production of a saleable commodity. On the other hand, a \$40/tonne CO<sub>2</sub> is comparable to the most optimistic cost of CO<sub>2</sub> avoided reported for CCS. Accordingly, a \$40/tonne CO<sub>2</sub> permit price would be sufficient to make CCS economic in various sectors [31], whereas a \$100/tonne CO<sub>2</sub> is approximately the permit price considered necessary for the widespread adoption of CCS [32]. These three permit prices comprise the range of values expected if the adoption of serious regulations of GHG emissions takes place.

Based on the above, understanding the impact of incorporating carbon prices within the electricity system is necessary in the present work. Therefore, the selected carbon prices are applied to different types of generating units (within the power network); whereas, its impact is evaluated in terms of the generating units' capacity factor. Figure 8 illustrates that the average capacity utilization of the nuclear plants (at Astor and Attlee) and hydroelectric units (at Aubrey) remain unchanged by the GHG regulation. These units are non-emitting, and consider lower marginal operating costs than the fossil-fired units. Thus, in practice they are fully utilized in the base case, and remain so after carbon prices are imposed. Additionally, it is observed that as the carbon price increases, the capacity utilization increases for oil-fired units, and decreases for coal-fired units (with the exception of the 376 MWe generating unit with 85% CO<sub>2</sub> capture installed at Austen). This indicates that the higher the carbon price, the lower the utilization of high-emitting generating units. Another estimation of the carbon price impact in the electricity system is given by the change in average power output. Figure 4 reveals that the coal-fired units (e.g., the 76 MWe units at Abel and Adams, the 155 MWe units at Arthur, and the units at Asser and Austen) present a significant reduction in their average power output and

corresponding emissions. Accordingly, as the stringency in GHG emissions regulation increases, the effect on the units' utilization also increases. For example, higher CO<sub>2</sub> permit prices results in power supply shifts from higher (i.e., coal-fired plants) to lower (i.e., natural gas and oil fired plants) emission intensity units.



**Figure 4.** Capacity factor for different CO<sub>2</sub> permit prices for the electricity system buses<sup>30</sup>

Accordingly, the CO<sub>2</sub> emissions are lower when a carbon price is incorporated in the system, and thus the greater the carbon price the lower the emissions. Table 4 summarizes the results in terms of CO<sub>2</sub> emissions for the base case and different stringencies of GHG regulation. Therefore, the higher the GHG permit prices the lower the CO<sub>2</sub> emission intensity (CEI) as shown in Table 4.

**Table4.** Summary of CO<sub>2</sub> emissions and reductions

Scenario	$\dot{m}^{CO_2}$ (t CO <sub>2</sub> /h)	$\Delta CO_2$ (t CO <sub>2</sub> /h)	CEI (t CO <sub>2</sub> /MWh <sub>e</sub> )
Base Case	995	-	0.483
\$15/tonne CO <sub>2</sub>	980	14.9	0.476
\$40/tonne CO <sub>2</sub>	959	36.5	0.466
\$100/tonne CO <sub>2</sub>	920	75.0	0.447

Although, the increase in fuel costs is significant, the cost of acquiring CO<sub>2</sub> permits is the main cause for most of the generation cost increase. As a result, the higher the carbon tax price, the higher the CoE to produce power from high emission-intensity generating units as the coal-fired ones. In Table 5, the first column displays the CAA calculated using values of CoE that do not include the cost of acquiring CO<sub>2</sub> emission permits; while for the second column the cost of CO<sub>2</sub> permits is included. In terms of electricity price, the CCA results demonstrates that the greater the permit price, the greater the electricity price.

**Table5.** Cost of CO<sub>2</sub> avoided for load balancing scenarios

Scenario	CCA w/o permits (\$/tonne CO <sub>2</sub> )	CCA w permits (\$/tonne CO <sub>2</sub> )
\$15/tonne CO <sub>2</sub>	29	1049
\$40/tonne CO <sub>2</sub>	61	1156
\$100/tonne CO <sub>2</sub>	64	1306

The energy benefit is also important in the present analysis, as it represents the revenue earned by the generators from selling power into the electricity market. Table 6 illustrates the change in net energy benefit obtained by generators at different GHG regulation levels. The most interesting observation is that most of the generators are more profitable with GHG regulations than without it, which means that the net energy benefit increases along with the carbon price.

**Table 6.** Change in net energy benefit due to GHG regulation

Scenario	<i>Net energy benefit</i> (\$/MWh <sub>e</sub> )	$\Delta$ <i>Net energy benefit</i> (\$/MWh <sub>e</sub> )
Base case	13.31	-
\$15/tonne CO <sub>2</sub>	16.30	2.99
\$40/tonne CO <sub>2</sub>	23.41	10.10
\$100/tonne CO <sub>2</sub>	47.54	34.23

## 6. Conclusion

In this work, a mixed-integer nonlinear programming (MINLP) model for the techno-economic assessment of CO<sub>2</sub> mitigation options in the electricity generation sub-sector was presented. Two scenarios were considered: load balancing and GHG regulations. In order to assess the validity of the proposed GHG mitigation strategies, an electricity system was modelled in GAMS for the IEEE RST '96 test case. The key element of this work includes the development of a short-term generation scheduling model. The model considers detailed operation of both the electricity system, and each one of the presented mitigation options. The present optimization model aims to reduce the electricity generation sub-sector GHG emissions while enhancing the units' utilization, maintaining suitable production costs and electricity prices.

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