

# Generation Capacity Expansion in Restructured Power Markets under a $CO_2$ Cap-and-Trade Program

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## Abstract

Determining the location, timing, and type of generation capacity to build in order to satisfy an increasing electricity demand presents a challenge to the generators. The implementation of a  $CO_2$  cap-and-trade program significantly compounds this challenge. The generators will have to consider the limits and costs of emissions as well as a broader array of generation technologies. In this paper, we develop a game-theoretic model that will allow generators to evaluate capacity expansion plans under different  $CO_2$  cap-and-trade scenarios. Our focus is on restructured power markets, where capacity expansion is driven by market competition as opposed to being coordinated by the system operators (as in regulated markets).

The model is implemented on a sample power network created from the electricity market data of northern Illinois in the U.S. The sample network is assumed to operate under a  $CO_2$  cap-and-trade program modeled similar to

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the Regional Greenhouse Gas Initiative (RGGI), which has been implemented recently in the northeastern U.S. The use of the model is demonstrated by obtaining expansion plans, for a planning horizon till the year 2030, for the generators in the network under different allowance price scenarios. The impact of cap-and-trade policy scenarios is examined via electricity prices, emissions reduction, demand levels, and technology market share over the planning horizon.

*Keywords:* decision support systems, game theory, environment

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## 1. Introduction

According to the U.S. Department of Energy's Annual Energy Outlook [1], electricity demand in the U.S. is expected to increase at an average rate of 1.1 % per year from 3,659 billion KWh in 2006 to 4,705 billion in 2030. Electricity generators throughout the country are facing the challenge of determining when, where, and what type of capacity to add in order to increase their market share. System operators, on the other hand, face the challenge of ensuring that installed capacity adequately meets this projected demand growth. In regulated markets, system operators coordinate generation expansion, whereas in restructured markets, competition guides capacity expansion with generators making decisions to maximize their profits. In this paper we focus on the capacity expansion problem in restructured markets.

In recent years, power markets have been subjected to new environmental regulations. In 1990, the Environmental Protection Agency in the U.S. introduced a federal market-based initiative to reduce the levels of  $SO_2$  and  $NO_x$  emitted by power plants. The current climate change legislation debate is centered around the implementation of a similar market-based program to reduce the  $CO_2$  levels in the atmosphere, and encourage greener electricity generation. Since electricity generators are responsible for about 40% of the  $CO_2$  emissions in the U.S. [2], any program aimed at reducing  $CO_2$  emissions will have a significant impact on the power generation sector. In fact, if an emissions control program is to achieve its goals, there will have to be a shift from the current fossil-fuel technologies to nuclear power and renewable sources. Thus, power generators need to assess the potential implications of a  $CO_2$  emissions control plan when making generation expansion decisions. The most commonly discussed federal measures to control  $CO_2$  emissions are: a carbon tax, and a  $CO_2$  cap-and-trade program. Thus far, the only  $CO_2$

emissions control program implemented in the U.S. is the Regional Greenhouse Gas Initiative (RGGI), which is a regional cap-and-trade program. In this research, we develop a game theoretic model to obtain capacity expansion plans for generators in a restructured market under a  $CO_2$  cap-and-trade program.

A  $CO_2$  cap-and-trade program will establish a **cap** on the total quantity of  $CO_2$  emissions allowed in a geographic region. A certain number of **allowances** (consistent with the cap) will then be issued. Fossil fuel generators will need to procure a sufficient number of allowances in order to produce electricity and avoid costly penalties. Allowances can be **traded** among the market participants. This general framework is common to all  $CO_2$  cap-and-trade programs that are either already implemented or are being considered. Albeit the common framework, the programs may differ as to how they treat various design attributes including stringency of the cap, upstream or downstream point of regulation, method of allowance distribution (sold via auction, free grandfathering, or a combination of both), and banking of allowances. The choice of these attributes continues to be a source of debate among the policymakers. The capacity expansion model presented in this paper provides an effective instrument for policymakers to assess various alternatives.

Restructuring of electricity markets began in the early 1990s. All the capacity expansion literature during most of that decade and prior to it addressed the expansion problem in regulated markets. These papers, [3, 4, 5, 6], present optimization models where a central planning authority solves a cost minimization problem subject to transmission constraints. In restructured electricity markets, capacity expansion decisions are not coordinated by a central authority, but instead made independently and non-cooperatively by competing generators in a network. Consequently, the expansion models developed for regulated markets are not applicable in the restructured settings. The dynamic noncooperative interactions of the generators, retailers, and investors in restructured electricity market are best represented by game-theoretic models.

One of the first game-theoretic models for capacity expansion in restructured power markets is presented in [7]. The competition is modeled using Cournot theory of oligopoly. Generators decide on how much capacity to expand, new entries are not allowed, and the expansion decisions are made simultaneously by all competitors. Each player seeks to maximize its profit subject to operational and physical constraints. The Cournot equilibria is ob-

tained using an iterative search procedure that maximizes the profit of each player, one at a time, while keeping all other players' actions fixed. The state spaces of the expansion quantity variables are considered to be continuous for each generator. In [8], two imperfect competition models for capacity expansion are presented: 1) an open-loop Cournot model similar to the model in [7], in which each generator selects its capacity and generation plans at the same time assuming the generation levels of its competitors are known; 2) a closed-loop Cournot model where capacity decisions are made in the first stage and operation decisions are made in the second stage. Equilibrium conditions in both of these models are established resulting in a quadratic programming and an MPEC model, respectively.

A different approach to model the capacity expansion problem was taken in [9] where a two-tier matrix game model is presented. The upper tier game models the competition in generation investment, while the lower tier is a supply function game that captures the competition at the power network operational level. Each matrix game is solved using a reinforcement learning algorithm. Risk due to volatilities in profits is incorporated in the payoffs via a *conditional value at risk* (CVaR) measure. A game theoretic model that incorporates  $CO_2$  emissions in the expansion problem is presented in [10]. Their model is similar to the open-loop Cournot in [8] but the operational decision variables are not only restricted to the electricity market but also to the allowance and green certificate markets. Competition in the electricity market is modeled using the conjectural variations approach and the allowances and green certificate markets are assumed to be perfectly competitive. Prices of allowances and green certificates are obtained endogenously.

Our approach is different from those presented in [7], [8], and [10] in that we consider a **discrete** set of feasible expansion plans for each generator, for a time horizon and a forecasted growth in demand. The expansion plans take into account the constraints of capital availability, network location, lead time, and technology. We assess the financial performance of these plans by assuming that all generators implement their plans simultaneously at the beginning of the time horizon (i.e., no leader-follower dynamics are present). This performance assessment is based on the outcome of the competition between the generators in both the electricity market and the  $CO_2$  allowance market. The competition in the electricity market is modeled assuming that each generator has a discrete set of supply function bids that is consistent with its mix of available capacity and technology. We consider transmission constraints and resulting congestion to accurately assess the performance of

each of the expansion plans (these features are not considered in [7], [8], and [10]). The  $CO_2$  allowances market is also modeled for suitable segments of the time horizon assuming that generators have a discrete set of allowance bids comprising price and quantity. As in [10], equilibrium allowance prices are determined endogenously by our model. Our approach considers discrete sets of expansion plans and supply function bids as in [9]. However, we also model the competition among the generators in the allowance market. Additionally, we consider a multi-year time horizon with construction lead times for new plants.

Papers that discuss the implications of a  $CO_2$  cap-and-trade program, but that are not particularly focused on capacity expansion, are [11, 12]. In [11], an economy-wide analysis of different cap-and-trade proposals considered by the U.S. Congress in spring 2007 is presented. The analysis is performed using the MIT Emissions Prediction and Policy Analysis (EPPA) model. EPPA simulates the world economy through time with special emphasis on creating scenarios of greenhouse gas emissions [13]. Allowance prices and expected emissions reductions are presented for each cap-and-trade proposal. In [12], the energy and economic implications of the State of Maryland joining RGGI are presented. The analysis is performed by integrating three components: a simulation model for interregional trade among regional electricity markets, a market equilibrium model that incorporates market power in regional electricity markets, and a software system to assess economic impacts by industrial sector. Some of the findings of the study include distinct but modest emissions reductions, and reduced profits for coal generator, though coal plants are not retired. Other studies analyzing the implications of cap-and-trade programs can be found in [14, 15].

To summarize, in this paper we present a game theoretic model for capacity expansion in restructured electricity markets that incorporates  $CO_2$  emissions trading. We consider transmission constraints and the effect of congestion in the electricity market. The model allows for the consideration of different design attributes of a  $CO_2$  cap-and-trade program. The expansion plans derived from our model provide information regarding capacity, location, technology, and the time of expansion. The model is intended to be used by the generators to evaluate expansion plans under different  $CO_2$  cap-and-trade programs for a given time horizon and a given forecast in demand growth.

The rest of the paper is organized as follows. Section 2 presents the components of the game theoretic model: expansion game, allowance game,

and electricity game, and how the markets they represent interact with each other. In Section 3 we present an algorithm to solve the model and discuss its computational implementation. An application to the northern Illinois power market is presented in Section 4. Section 5 presents the concluding remarks.

## 2. Game Theoretic Model

### 2.1. Background

We consider a network with  $N$  nodes,  $T$  transmission lines, and  $n$  generators. Each generator owns an array of plants based on different technologies at one or more nodes in the network. We assume that the region served by the power network operates under a  $CO_2$  cap-and-trade program, where the generators are required to obtain allowances allocated via auction. The generators bid for allowances with price and quantity, and surrender the acquired allowances at the end of the production period commensurate with their emissions. It is assumed that the generators pass the cost of the allowances on to the consumers in the electricity market.

### 2.2. Schematic Representation

A schematic of the game theoretic modeling framework (for a hypothetical scenario with 3 players) is presented in Figure 1. The *expansion game* represents all possible combinations of the expansion plans of the generators. An expansion plan comprises a set of yearly actions to add generation capacity (or to do nothing) over the planning horizon. The attributes of an action include location of the new capacity and its size, technology, and cost. Each of the combinations in the expansion game (e.g., the shaded portion) represents a specific network generation portfolio (in terms of nodal capacities and technology mix). Thus, an expansion plan combination directly influences the generators' bid strategies in the *allowance game* for each year of the planning horizon  $H$ . In turn, each combination of the allowance bid strategies (and the corresponding allowance settlement) influences the supply function bid strategies in the *electricity game*. This is due to the impact of the emissions cost on the electricity market settlement. Clearly, the action choices of the generators in the expansion, allowance, and electricity games, collectively determine the profit from the electricity market. In our modeling framework, this profit is used to construct the payoff matrices for the

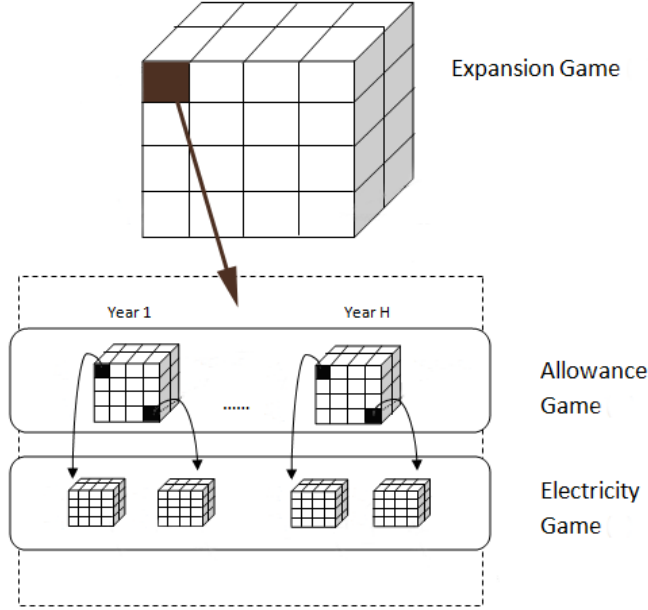


Figure 1: A Schematic for the Game Theoretic Framework

allowance game. Finally, the equilibrium profits from the electricity and the allowance markets are used to construct the payoff matrix of the expansion game, whose solution provides the equilibrium expansion plan combination. Consequently, the solution methodology for the game theoretic framework must begin by solving the electricity game, followed by the allowance and expansion games. Note that the inherent chronological order for selecting actions in the expansion, allowance, and electricity markets (e.g., start of the planning horizon for the expansion, quarterly for allowance, and daily for electricity, respectively) requires a tiered modeling framework and a solution methodology based on backward induction that we have adopted.

### 2.3. Expansion-Allowance-Electricity Games

Let  $x_i = (x_i^1, \dots, x_i^H)$  denote an expansion plan vector for the  $i^{th}$  generator, of which each element  $x_i^t$  is also a vector comprising expansion capacity and technology for each node location. Let  $y_i = (y_i^1, \dots, y_i^H)$  and  $z_i = (z_i^1, \dots, z_i^H)$  denote the allowance bid and the supply function bid vectors, respectively, where, for any year  $t$ ,  $y_i^t$  is a 2-tuple comprising allowance price and quantity, and  $z_i^t$  is also a 2-tuple comprising the intercept and the

slope of the supply function. Similarly, let  $x_{-i}$ ,  $y_{-i}$ , and  $z_{-i}$ , denote the expansion plans, allowance bids, and supply function bid vectors, respectively, of the rest of the generators for the planning horizon. Each generator,  $i = 1, \dots, n$ , selects equilibrium actions  $x_i^*$ ,  $y_i^*$ , and  $z_i^*$  via the following discrete maximization problem,

$$\begin{aligned} & \max_{x_i} f(x_i, x_{-i}) - C(x_i) + R(x_i), & (1) \\ & s.t. \quad \max_{y_i^t, z_i^t} g(y_i^t, z_i^t, y_{-i}^t, z_{-i}^t), \quad \forall t \\ & \quad x_i \in \Xi_i, \quad y_i^t \in \Upsilon_{x_i}, \quad z_i^t \in \Psi_{x_i, y_i^t} \end{aligned}$$

where  $f(x_i, x_{-i}) = \sum_{t=1}^H \frac{g(y_i^{t*}, z_i^{t*}, y_{-i}^{t*}, z_{-i}^{t*})}{(1+r)^t}$  is the present value of the total joint profit from the allowance and electricity markets for generator  $i$  from year 1 to  $H$  if expansion plan  $x_i$  is implemented, when the rest of the generators implement  $x_{-i}$ . The discount rate is denoted by  $r$ ,  $C(x_i)$  is the cost of investment of plan  $x_i$ , and  $R(x_i)$  is the residual value of the installed capacity at the end of year  $H$ .  $\Xi_i = \{x_{i1}, x_{i2}, \dots, x_{im_i}\}$  denotes a set of  $m_i$  feasible alternative expansion plans for each generator  $i$ .  $\Upsilon_{x_i}$  denotes a finite discrete set of  $CO_2$  allowance bid strategies for each expansion plan  $x_i$ , and  $\Psi_{x_i, y_i^t}$  denotes a finite discrete set of supply function bid strategies for each combination of  $x_i$  and  $y_i^t$ .

We assume that each generator develops a finite number of expansion plans in  $\Xi_i$  considering an installed capacity target for year  $H$  based on the network demand growth forecast and other real life constraints on location, timing, and budget. This bounds the solution state-space of the game. The  $CO_2$  bidding strategies (comprising price and quantity) in set  $\Upsilon_{x_i}$  are guided by the generation portfolio resulting from the implementation of expansion plan  $x_i$ , since the proportion of green and fossil fuel technologies in the portfolio dictates the allowance needs. Similarly, the supply function bid strategies (comprising slope and intercept of the supply function) in  $\Psi_{x_i, y_i^t}$  are guided by the  $(x_i, y_i^t)$  pair, which determines the nodal generation capacities, cost of generation, and allowance allocation and cost. It is clear that solving (1) requires the equilibrium bids  $(y_i^{t*}, z_i^{t*})$  from the allowance and electricity games (see first constraint in (1)).

A unique feature of modeling the competition in the allowance and the electricity markets is that same payoffs are used in solving the corresponding

games, though the settlement of electricity markets occur after the settlement of the allowance markets. In this regard, without loss of generalization, we assume that allowances are auctioned once a year followed by the electricity auction in the day-ahead and spot markets throughout the year. For each bid combination ( $y_i^t \in \Upsilon_{x_i}, \forall i$ ) that is considered in the allowance market, the corresponding electricity market bids choices ( $z_i^t \in \Psi_{x_i, y_i^t}, \forall i$ ) are formulated. Then for each allowance and electricity bid combination, a joint payoff  $g(y_i^t, \dots, y_n^t; z_i^t, \dots, z_n^t)$  is formulated. This joint payoff is used to first solve the electricity game (i.e., to find  $z_i^{t*}, \forall i$ ) whose equilibrium joint payoff  $g(y_i^t, \dots, y_n^t; z_i^{t*}, \dots, z_n^{t*})$  is then used to solve the allowance game (i.e., to find  $y_i^{t*}, \forall i$ ).

Following the formulation presented in (1), the allowance and the electricity games can be jointly presented as follows. For each generator  $i$ ,

$$\begin{aligned} & \max_{y_i, z_i} g(y_i^t, z_i^t, y_{-i}^t, z_{-i}^t), \forall t & (2) \\ & s.t. \quad y_i^t \in \Upsilon_{x_i}, \quad z_i^t \in \Psi_{x_i, y_i^t} \end{aligned}$$

where  $g(y_i^t, z_i^t, y_{-i}^t, z_{-i}^t)$  is the joint payoff from the allowance and electricity games, given as

$$g(y_i^t, z_i^t, y_{-i}^t, z_{-i}^t) = r(y_i^t, z_i^t, y_{-i}^t, z_{-i}^t) + s(y_i^t, z_i^t, y_{-i}^t, z_{-i}^t) \quad (3)$$

where  $r(\cdot)$  and  $s(\cdot)$  represent the payoffs from the electricity and the allowance markets, respectively. We explain how to compute the payoffs next.

### 2.3.1. Electricity market payoff

Generators are assumed to compete in the electricity market by submitting a supply bid vector  $z_i^t = (z_{i_1}^t, z_{i_2}^t, \dots, z_{i_{n_i}}^t) \in \Psi_{x_i, y_i^t}$ . Each element of the vector represents the supply bid for each of the  $n_i$  power plants generator  $i$  owns in the network. Each individual supply bid  $z_{i_k}^t$  is defined by the pair  $(a_{i_k}^t, b_{i_k}^t)$ , where the first element is the intercept and the second is the slope of the supply curve, given as  $p = a_{i_k} + b_{i_k}q$ , where  $p$  and  $q$  are price and quantity, respectively. It is considered that the consumers participate in the electricity market by submitting linear demand bids. The payoff for generator  $i$  in the electricity market in year  $t$  is computed as follows.

$$r(y_i^t, z_i^t, y_{-i}^t, z_{-i}^t) = \sum_{k=1}^{n_i} q_{i_k} LMP_{i_k} - \sum_{k=1}^{n_i} (a_{i_k} q_{i_k} + \frac{1}{2} b_{i_k} q_{i_k}^2), \quad (4)$$

where  $q_{i_k}$  is the quantity of electricity produced by plant  $k$  and  $LMP_{i_k}$  is the locational marginal price at the node where plant  $k$  is located. The values for  $q_{i_k}$  and  $LMP_{i_k}$  in (4) are obtained by solving the following Optimal Power Flow (OPF) problem as presented in [16],

$$\begin{aligned}
& \max \sum_h B_h[p_h] - \sum_h C_h[p_h], & (5) \\
& \text{subject to:} \\
& Q_h - \sum_{\alpha \in \alpha(h)} q_\alpha[p_h] = 0 \quad \forall \text{ node } h \\
& D_h - \sum_{\beta \in \beta(h)} d_\beta[p_h] = 0 \quad \forall \text{ node } h \\
& Q_h - D_h - \sum_{l \in l(h)} (t_{hl} - t_{lh}) = 0 \quad \forall \text{ node } h \\
& \sum_{hl \in A(v)} R_{hl}(t_{hl} - t_{lh}) = 0 \quad \forall \text{ voltage loop } v \\
& t_{hl} \leq T_{hl} \quad \forall \text{ arc } hl \\
& t_{hl} \geq 0 \quad \forall \text{ arc } hl
\end{aligned}$$

where  $p_h$  is the LMP at node  $h$ ,  $B_h[p_h]$  is the total benefit to consumers at node  $h$ ,  $C_h[p_h]$  is the total cost to producers at node  $h$ ,  $Q_h$  and  $D_h$  are the total supply and total demand at node  $h$  respectively,  $\alpha(h)$  is the set of producers at node  $h$ ,  $\beta(h)$  is the set of consumers at node  $h$ ,  $q_\alpha[p_h]$  is the quantity supplied by producer  $\alpha$  located at node  $h$ ,  $d_\beta[p_h]$  is the quantity demanded by consumer  $\beta$  at node  $h$ ,  $l(h)$  is the set of nodes directly connected through a transmission line with node  $h$ ,  $t_{hl}$  is the power flow between nodes  $h$  and  $l$ ,  $A(v)$  is the set of links that define loop  $v$ ,  $R_{hl}$  is the reactance of link  $hl$ , and  $T_{hl}$  is the fixed capacity of link  $hl$ .

### 2.3.2. Allowance Market Payoff

Let  $\Upsilon_{x_i} = \{y_{i1}, y_{i2}, \dots, y_{ip_i}\}$  be the set of  $p_i$  allowance bids that generator  $i$  chooses from, where each bid consists of unit price and desired number of allowances. Though the type of auction used to allocate the allowances depends on the design of the  $CO_2$  cap-and-trade program, without loss of generality, we adopt a uniform-price sealed-bid auction (as in RGGI [17]). Uniform-price sealed-bid auction is modeled as a linear program. The market

clearing price of the allowance auction,  $p_a^t$ , corresponds to the price of the last accepted bid. The constraints in the linear program includes number of allowances available for each period, reserve price, and limit on the number of allowances that each generator can receive. Let  $n_a^t[y_i]$  denote the number of allowances allocated to generator  $i$  in year  $t$  as a function of the allowance bid  $y_i$ ,  $n_c^t[z_i]$  is the number of allowances *consumed* by generator  $i$  during year  $t$  as a function of the electricity bid  $z_i$ , and  $\hat{p}_a^t$  is the price at which allowances are traded in the secondary market (an exogenous quantity). The profit (loss) from the allowance market is computed as follows,

$$s^t[y_i, z_i, y_{-i}, z_{-i}] = \hat{p}_a^t(n_a^t[y_i] - n_c^t[z_i]), \quad (6)$$

We have assumed that the auction trades for allowances in the current vintage year only (not for future years). Thus, if the generators do not have enough allowances to surrender at the end of each electricity market production period (i.e., to compensate for the emissions) they are subjected to penalties. Such a situation arises when a generator fails to procure sufficient number of allowances from the auction and the secondary market. RGGI, for instance, considers a penalty of 3 times the outstanding balance of allowances.

### 3. Solution Procedure

A schematic of the solution algorithm is presented in Figure 2. In step 1, the following indices are initialized:  $t = \{1, 2, \dots, H\}$  for years in the planning horizon  $H$ ,  $j = \{1, 2, \dots, |\Xi|\}$  for set of expansion plan combination  $\Xi = \Xi_1 \times \Xi_2 \times \dots \times \Xi_n$ ,  $k = \{1, 2, \dots, |\Upsilon|\}$  for set of allowance bid combination  $\Upsilon = \Upsilon_{x_1} \times \Upsilon_{x_2} \times \dots \times \Upsilon_{x_n}$ , and  $l = \{1, 2, \dots, |\Psi|\}$  for set of supply bid combination  $\Psi = \Psi_{x_1 y_1} \times \Psi_{x_2 y_2} \times \dots \times \Psi_{x_n y_n}$ . Steps 2 and 3 ensure that each expansion plan combination is evaluated, while step 4 ensures that this evaluation is made for each year of the planning horizon. In step 5, the set of allowances bid strategies  $\Upsilon_{x_i}^t$  is developed for each generator  $i$  with an expansion plan  $x_i$  for year  $t$ . Steps 6 and 7 ensure that each allowance bid combination is evaluated. In step 8, the allowance auction is cleared, which gives the allowance market clearing price and allowance quantities. In step 9, the set of supply function bid strategies  $\Psi_{x_i y_i}^t$  is developed for each generator  $i$ . Steps 10 and 11 ensure that each supply function bid combination of the generators is evaluated. The profit from the allowance and the electricity

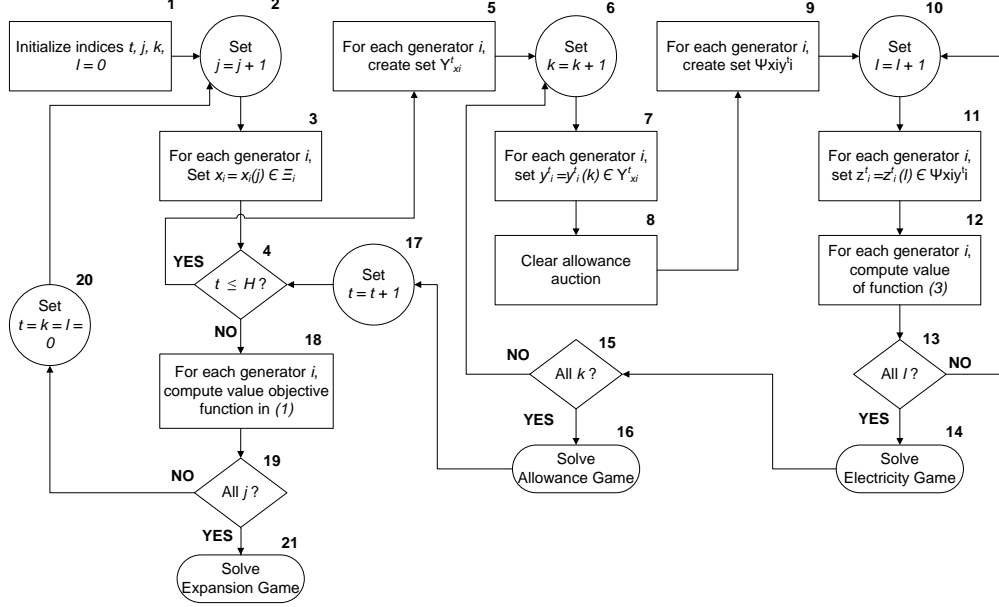


Figure 2: Solution Algorithm Flow Diagram

markets for year  $t$ , as given in (3), is computed in step 12. These profits are used to form the electricity game payoff matrix. In step 13, we check if all the supply bid function combinations have been evaluated. If so, the electricity game is solved in step 14, using the reinforcement learning (RL) algorithm (explained below). The solution of the game provides the equilibrium supply function bid combination. Step 15 checks if all the allowance bid combinations have been evaluated. Note that, the payoff matrix for the allowance game is constituted by the equilibrium profits from the electricity games. The allowance game is solved in step 16, which yields the equilibrium allowance bid combination. Steps 17 and 4 together ensures that the loop comprising steps 5 through 16 is repeated for each year of the planning horizon. The value of the objective function (given by the present value of profit from the years in planning horizon, minus the overnight cost, plus the residual value of the installed capacity), as defined in (1), is computed in step 18. This completes the evaluation of an expansion plan combination. Steps 19 and 20 ensure that all expansion plan combinations are evaluated.

Finally, in step 21 the expansion game is solved using the RL algorithm and the equilibrium expansion plan combination is obtained.

We use the reinforcement learning (RL) algorithm developed in [18] in steps 14, 16, and 21. The RL algorithm uses a value-iteration approach to find a pure Nash equilibrium solution, when one or more exists, otherwise it finds a pure out-of-equilibrium solution [19]. The following are the main steps of the RL algorithm, presented in the context of the expansion game.

- **Step 1.** Let iteration count  $p = 0$ . Initialize R-values for each generator  $i$  with  $m_i$  expansion plan choices  $(R_0(i, 1), \dots, R_0(i, m_i))$  to an identical small positive number. Also initialize the learning parameter  $\gamma_0$ , exploration parameter  $\phi_0$ , and parameters  $\gamma_\tau$  and  $\phi_\tau$  needed to obtain suitable decay rates of learning and exploration. Let *Maxsteps* denote the maximum iteration count.
- **Step 2.** If  $p < \text{Maxsteps}$ , continue learning of the R-values through the following steps:

- **Action Selection:**

Greedy action selection:

Each generator  $i$ , with probability  $(1 - \phi_p)$ , chooses an action  $x_i$  for which  $R_p(i, x_i) \geq R_p(i, \bar{x}_i)$  where  $\bar{x}_i$  stands for all the other expansion actions excepting  $x_i$ . A tie is broken arbitrarily.

Exploratory action selection:

With probability  $\phi_p$ , a generator chooses an action  $x_i$  from the possible expansion actions choices (excluding the greedy action), where each action can be chosen with equal probability.

- **R-Value Updating:**

Update the specific R-values for each generator  $i$  corresponding to the chosen action  $x_i$  using the learning scheme given below.

$$R_{p+1}(i, x_i) \leftarrow (1 - \gamma_p)R_p(i, x_i) + \gamma_p(r_i(x_i, x_{-i})), \quad (7)$$

where  $r_i(x_i, x_{-i})$  is the payoff of generator  $i$  for choosing expansion plan combination  $x_i$  when the other generators choose actions  $x_{-i}$ . Note that  $r_i(x_i, x_{-i}) = f(x_i, x_{-i}) - C(x_i) + R(x_i)$  (see the objective function in 1).

- Set  $p \leftarrow p + 1$ .

- Update the learning parameter  $\gamma_p$  and exploration parameter  $\phi_p$  as in [18].
  - If  $p < MaxSteps$ , go back to beginning of Step 2, else go to Step 3.
- **Step 3.** From the set of  $R$ -values, select the expansion action  $x_i^*$  for each generator  $i$  as follows.

$$x_i^* = \max_{x_i} R_p(i, x_i) \quad (8)$$

The RL algorithm is applied in a similar way to solve the allowance and electricity games.

### 3.1. Computational Issues

The computational challenges of the solution procedure stem from the large number of OPFs that need to be solved when the sets  $\Xi$ ,  $\Upsilon$ , and  $\Psi$  have large cardinalities. Since an OPF problem is solved each time step 12 of the procedure is visited (see Figure 2), then the total number times an OPF solution is invoked is given by the product  $|\Xi| \times |\Upsilon| \times |\Psi|$ . However, since the payoffs of the expansion plan combinations can be evaluated independently, the loop comprising steps 2 through 20 can be run in parallel using a distributed computing framework. Moreover, this model is intended to support the long term strategic planning process of the generators and regulators, and, hence, it is not a real time tool. Computational time, therefore, is not a major concern.

## 4. Application of the model to Illinois Electricity Market

In this section we demonstrate the use of our model on a 9-node network representing the northern region of the Illinois power network. We assume a RGGI type cap-and-trade program in operation for the network. The planning horizon considered is from 2007 through 2030, which is supported by a complete set of market data (demand, installed capacity, transmission capacity, generation allocation, and LMPs) for the year 2007. We obtain equilibrium expansion plans for the generators and the corresponding generation distribution (between coal, gas, and nuclear), electricity prices, generator

profits, emissions, and allowance prices for each year of the planning horizon. We contrast these outcomes for three cap-and-trade scenarios varying the allowance prices.

#### 4.1. Background

Market data was simulated by the Argonne National Laboratory (ANL) for a report submitted to the Illinois Commerce Commission, [20]. According to the report, the Illinois electricity market, in 2007, had 4 main producers of electricity (henceforth referred to as Generators 1 through 4), whose combined market share was approximately 90%. The capacity of Generator 1 was predominantly nuclear, whereas the other 3 generators owned mostly coal and natural gas-fueled power plants. The report also indicated that most of the electricity consumed in the state was produced by nuclear and coal plants, with natural gas plants producing only a marginal quantity. More details about the network, as reported in [20], are presented in Table 1. We constructed a 9-node model network (see Figure 3) replicating the electricity market conditions reported in [20]. Seven of the nine nodes represent different zones of the power network (each node being an aggregation of the actual nodes). One of the two remaining nodes aggregates the rest of the nodes in the Illinois network, while the other aggregates the nodes outside of the state that interact with the Illinois network.

Company	Node	Type	Capacity (MW)	Company	Node	Type	Capacity (MW)
Gen 1	NI-B	Gas	540	Gen 3	IN	Coal	3,160
Gen 1	IN	Gas	1,455	Gen 4	NI-C	Gas	212
Gen 1	IN	Coal	4,711	Gen 4	NI-D	Gas	414
Gen 2	NI-A	Nuclear	4,154	Gen 4	NI-E	Gas	141
Gen 2	NI-F	Nuclear	4,156	Gen 4	NI-F	Gas	1,638
Gen 2	NI-G	Nuclear	2,305	Gen 4	NI-B	Coal	789
Gen 2	IN	Nuclear	944	Gen 4	NI-D	Coal	868
Gen 2	NI-D	Gas	328	Gen 4	NI-E	Coal	2,140
Gen 3	NI-B	Gas	398	Gen 4	NI-G	Coal	1,538
Gen 3	IN	Gas	484				

Table 1: Installed Capacity in the Model Network

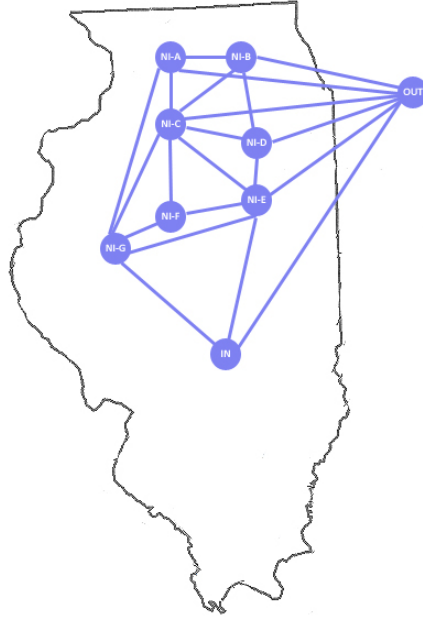


Figure 3: Nine-node Model for Illinois Network

#### 4.2. Capacity Expansion Scenario

We consider four choices of expansion plans for each of the four generators (see Table 2). The plant capacities in the expansion plans were chosen from the current plant capacities of the generators. Options for new nuclear plants were considered only in those nodes that currently host nuclear plants, to account for environmental and other restrictions. Construction times were obtained from a study by [21]. It is assumed that generators make the capacity available in the electricity market after the construction time has lapsed. The time required to obtain permits for new plants was not considered.

#### 4.3. Allowances Market Scenario

We consider a cap that is held constant for the period 2007-2015, which is then reduced on a yearly basis by 2.5 % until 2030. We assume that 100% of the allowances are auctioned. Each generator bids for allowances indicating price and quantity. The auction is assumed to be sealed-bid uniform-price

with a reserve price (the minimum acceptable bid in the allowance auction) and a restriction on the maximum number of allowances (40%) that a single generator can receive. Our primary objective in formulating the sample problem was to examine the impact of allowance reserve prices on the effectiveness of the cap-and-trade design. Therefore, we considered three different scenarios for reserve prices: \$ 3.38 based on the clearing prices obtained in the first RGGI auctions [22] (scenario 1), and two other scenarios (2 and 3) with higher reserve prices of \$5 and \$6, respectively. In order to limit the computational needs, we did not solve the allowance game, instead, we assumed the bidding strategies for each of the generators as follows. Generators 1, 3, and 4, which own only coal and natural gas plants at the beginning of the planning horizon (see Table 1), bid 1.5 times the reserve price, while generator 2 with no coal capacity and small natural gas plants bids the reserve price. When a generator incurs penalty by exceeding the allowed emission, it is assumed that the generator increases its bid price for the next period by 1.2 times. We also consider that generators trade any unused allowances at the end of each period in the secondary market. Additionally, it is assumed that the generators bank any surplus allowance, remaining after the end-of-period secondary trading, for the next period. The trading price of the allowances in the secondary market is considered to be 1.2 times the auction price of the period. If the overall balance of allowances at the end of a secondary trading period is negative, a 150% penalty is applied to the generator with negative balance, i.e., if a generator falls short of 100 allowances for a period, then the outstanding balance for the generator at the beginning of the next period is 150. The generators pass on the additional cost of penalty to the consumers through an increase in their electricity supply bids. It is considered that at the end of the planning horizon the generators pay off any outstanding allowance balance.

#### 4.4. *Electricity Market Scenario*

The 9-node network is depicted in Figure 3. We focus on the northern region of the state since most of the generation and peak loads are located in this area. Seven nodes that represent the electricity production and consumption in this area are named: NI-A, NI-B, NI-C, NI-D, NI-E, NI-F, and NI-G. Two other nodes are named: IN (which is a super node representing all the remaining nodes in the state) and OUT (which is a super node representing the out of state nodes that trade electricity with Illinois). Demand bid

curves were constructed for each node for year zero of the planning horizon based on the results in [20]. Subsequently, to represent a demand increase for each year of the planning horizon, the demand bid curves were shifted to the right as shown in Figure 4. The nodal capacities of each generator, by fuel

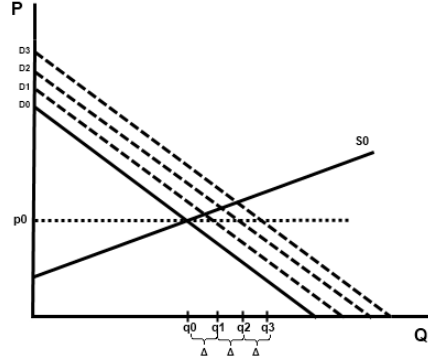


Figure 4: A Schematic Representation of Yearly Demand Increase

type, in year zero are presented in Table 1. Note for example that, in Table 1, 4154 MW in nuclear-based generation for generator 2 in node NI-A is obtained by adding the capacities of four different nuclear plants (1221 MW, 1199 MW, 867 MW, 867 MW) in the NI-A zone. Supply bid curves for year zero were constructed for each combination of the generator, node, and fuel type using the results in [20]. Throughout the planning horizon the supply bid curves are adjusted endogenously on a yearly basis to accommodate the total cost of allowances incurred by the generators. Fuel costs are assumed to remain same as year zero throughout the planning horizon.

#### 4.5. Results

We coded our capacity expansion model for the 9-node network in C, which was implemented using an Intel Core Duo 2.20 GHz processor. The embedded optimization problems (OPFs and allowance auctions) were modeled in C through a callable CPLEX library and solved using ILOG CPLEX version 10.1.

The equilibrium expansion plans selected by the generators in scenarios 1, 2, and 3 discussed earlier in this section, are presented in the uppermost part of Figure 5. It can be observed that, for the three scenarios considered,

Construction						Construction							
Plan	Technology	Cap. (MW)	Node	Begins		Plan	Technology	Cap. (MW)	Node	Begins			
Gen 1	Plan 1	Nuclear	1,221	NI-A	2007		Gen 3	Plan 1	Nuclear	1,221	NI-A	2007	
		Nuclear	867	NI-A	2013				Plan 2	Nuclear	1,221	NI-A	2024
	Plan 2	Nuclear	1,221	NI-A	2018			Plan 3		Gas	67	NI-B	2007
		Nuclear	867	NI-A	2024				Gas	67	NI-B	2009	
	Plan 3	Nuclear	1,221	NI-A	2007				Gas	67	NI-B	2011	
		Coal	320	IN	2013				Coal	320	IN	2013	
	Plan 4	Nuclear	1,221	NI-A	2024			Plan 4	Gas	67	NI-B	2024	
		Coal	320	IN	2021				Gas	67	NI-B	2026	
	Gen 2	Plan 1	Nuclear	1,221	NI-A	2007			Gas	67	NI-B	2028	
			Nuclear	1,221	NI-A	2013			Coal	320	IN	2021	
			Gas	554	NI-D	2019		Gen 4	Plan 1	Nuclear	1,221	NI-A	2007
		Plan 2	Nuclear	1,221	NI-A	2018				Nuclear	867	NI-A	2013
Nuclear			1,221	NI-A	2024		Plan 2		Nuclear	1,221	NI-A	2018	
Gas		554	NI-D	2015		Nuclear		867	NI-A	2024			
Plan 3	Nuclear	1,221	NI-A	2007		Plan 3	Coal	769	NI-B	2007			
	Nuclear	867	NI-A	2013			Coal	769	NI-B	2011			
	Nuclear	867	NI-A	2019			Coal	320	NI-B	2015			
Plan 4	Nuclear	1,221	NI-A	2024		Plan 4	Coal	769	NI-B	2022			
	Nuclear	867	NI-A	2012			Coal	769	NI-B	2026			
	Nuclear	867	NI-A	2018			Coal	320	NI-B	2019			

Table 2: Sample Expansion Plan Choices in Northern Illinois Electricity Market

the equilibrium expansion plans chosen by the generators are similar. This similarity is in part due to the limited number of action choices that were considered for the generators. However, as we discuss below, the chosen plans have different impacts on the market prices, demand for electricity, emissions reductions, and market share of generation technologies.

For the average LMPs, in Figure 5, we observe an upward trend. Though an increase in LMPs is expected from the implementation of an emissions control scheme, we note that it is also a result of the expected increase in demand over the planning horizon, which we have modeled as shown in Figure 4. It can also be seen that there are three distinct segments in each LMP plot. In the first segment, between years 2007 and approximately 2012, LMPs at all nodes increase steadily and at the same rate. as the new generation capacities of the chosen expansion plans are still in construction, the  $CO_2$  cap has not yet been lowered, and the allowance price is at its lowest level (see the allowance curve on the same figure). The second segment, between 2012 and 2020 (in scenario 1), 2024 (in scenario 2) and 2026 (in scenario 3), exhibits fluctuating LMPs that are somewhat identical across the nodes. We

note that the identical nature of the LMPs is caused by the excess capacity in the network brought about by the new nuclear plants that start operating in 2013. The LMP fluctuation, on the other hand, is triggered by both the excess capacity and the cap reduction, which can be further elaborated as follows. As the cap reduction begins and less allowances are made available, the generators find themselves in emissions violation and subjected to penalty. In the following year, the generators try to pass on the cost of penalty by increasing the supply bid prices, which causes the coal generation to be less competitive, supplying less power to the network, and producing less emissions. This, in the subsequent year, reduces the cap violation penalty and the generator supply bid prices, which results in coal generators supplying more power and violating the cap again. This cycle repeats until demand grows to a point where excess generation capacity is reduced and so is the fluctuation in coal generation from year to year, thereby reducing the fluctuations in the LMPs (as observed in the third segment of the LMP plots).

A similar but complimentary fluctuation can be seen in the demand and emissions values, where both demand and emissions are lower in years when the LMPs are higher and vice versa. It may be noted, as evident from the last segment of the emissions and market share plots, that the capacity mix of the network and the increased demand result in a steady selection of coal-based generation and increasing emissions cap violation under continuing cap reduction. As expected, the smallest violation of the cap is observed for scenario 3. It can also be seen from the demand plot that the demand elasticity (modeled via demand side bidding in the OPF) causes the network demand to be generally lower in scenario 3 than in scenario 2, and lower in scenario 2 than in scenario 1.

As to the market share by technology, Figure 5 shows that nuclear and coal generation undergo a similar fluctuation, whereby the nuclear generation peaks in years when supply bids for coal plants attempt to recover penalties due to cap violation in the previous year. Overall, for the period 2007-2030, the market share of nuclear generation exhibits a net increase of around 10%, natural gas-based generation exhibits a negligible net increase, while the coal generation decreases around 10%.

Figure 6 shows the overall effect of the cap-and-trade design on emissions reduction in each scenario. The line graph presents the emissions per MWh of electricity produced revealing the emissions reduction trend due to cap-and-trade in all three scenarios. Note that, this reduction trend is in contrast

SELECTED PLANS																	
Scenario 1 - Reserve Price = \$3.38/allowance					Scenario 2 - Reserve Price = \$5.00/allowance					Scenario 3 - Reserve Price = \$6.00/allowance							
Plan	Technology	Capacity	Node	Construction Begins	Plan	Technology	Capacity	Node	Construction Begins	Plan	Technology	Capacity	Node	Construction Begins			
Gen 1	Plan 3	Nuclear	1,221	NI-A	2007	Gen 1	Plan 3	Nuclear	1,221	NI-A	2007	Gen 1	Plan 3	Nuclear	1,221	NI-A	2007
		Coal	320	IN	2013			Coal	320	IN	2013			Coal	320	IN	2013
Gen 2	Plan 1	Nuclear	1,221	NI-A	2007	Gen 2	Plan 1	Nuclear	1,221	NI-A	2007	Gen 2	Plan 1	Nuclear	1,221	NI-A	2007
		Nuclear	1,221	NI-A	2013			Nuclear	1,221	NI-A	2013			Nuclear	1,221	NI-A	2013
	Gas	554	NI-D	2019	Gas		554	NI-D	2019	Gas	554		NI-D	2019			
Gen 3	Plan 3	Gas	67	NI-B	2007	Gen 3	Plan 4	Gas	67	NI-B	2024	Gen 3	Plan 3	Gas	67	NI-B	2007
		Gas	67	NI-B	2009			Gas	67	NI-B	2026			Gas	67	NI-B	2009
	Gas	67	NI-B	2011	Gas		67	NI-B	2028	Gas	67		NI-B	2011			
	Coal	320	IN	2013	Coal		320	IN	2021	Coal	320		IN	2013			
Gen 4	Plan 1	Nuclear	1,221	NI-A	2007	Gen 4	Plan 1	Nuclear	1,221	NI-A	2007	Gen 4	Plan 1	Nuclear	1,221	NI-A	2007
		Nuclear	867	NI-A	2013			Nuclear	867	NI-A	2013			Nuclear	867	NI-A	2013

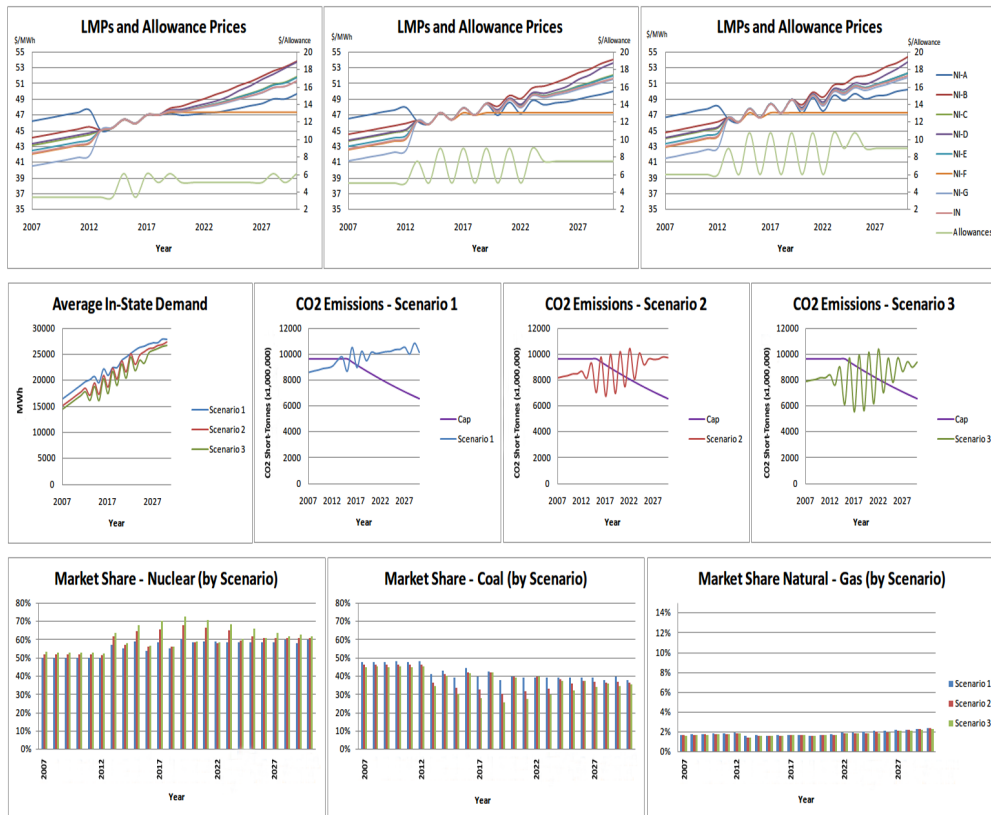


Figure 5: Model Results for the Sample Network under Three Cap-and-Trade Scenarios

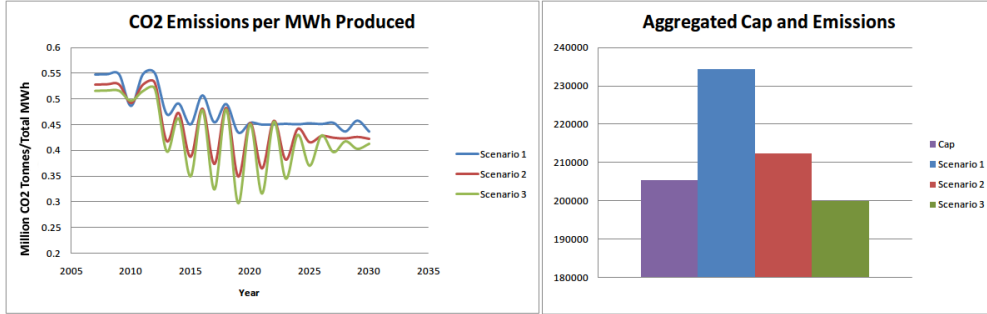


Figure 6:  $CO_2$  Emissions per MWh (left) - Aggregated Cap and Emissions for the Planning Horizon (2007-2030) (right)

to the increasing trend for *total emissions* that we observe in Figure 5, which is caused in part by the increase in demand over the planning horizon. It can also be observed that emissions per MWh in scenario 3 are reduced approximately 20 % over the period 2007-2030. The bar graph in Figure 6 depicts the aggregated cap (i.e., the total allowed emissions during 2007-2030) and the aggregated emissions in each of the scenarios. It can be seen that in scenario 3, contrary to the other scenarios, the aggregated emission is below the aggregated cap, which attests to the higher effectiveness of the pricing scheme in scenario 3.

## 5. Conclusions

Cap-and-trade is the most discussed scheme to control  $CO_2$  emissions in the U.S. In recent years, the European Union and a group of Northeastern states in the U.S. have implemented such programs. Generation expansion decisions will need to be made taking into account any such regulation. In fact, if a cap-and-trade program is to succeed there will have to be a shift from dominant fossil-fuel technologies to low-emission technologies such as renewables or nuclear power.

In general, a cap-and-trade program establishes a cap on the total quantity of  $CO_2$  emissions allowed in a geographic region. Allowances (or pollution permits) are issued that can be traded among the market participants. These general features notwithstanding, there are several other critical attributes of a cap-and-trade program that need to be adequately set such as the size of the cap, method of allowance distribution, penalties, and auction rules (limit on number of allowances a single market participant can obtain, reserve price).

In this paper, we develop a game theoretic model for generation capacity expansion that is able to accommodate different designs of a cap-and-trade program to assess their impact on expansion decisions. The model incorporates the competition among the generators in the allowance and electricity markets. We develop a solution algorithm for the game theoretic model that provides the equilibrium expansion plans, allowance bid strategies, and supply function bid strategies of the generators for a specific planning horizon.

The paper also presents a case-study based on the northern Illinois power network, which is subjected to a hypothetical cap-and-trade program (with features similar to those considered in RGGI). The results provide insight with regards to future electricity prices,  $CO_2$  emissions reductions, and technology expansion decisions. However, we did not consider other elements of the future electricity markets under emissions regulation, such as renewable power, offsets, recycling of  $CO_2$  revenue, and demand side efficiency incentives. With regards to these elements, we offer the following comments.

- We did not include renewables because we did not have any data for this type of generation for the Illinois network. From an emissions perspective, renewable power is comparable to nuclear power. However, other aspects are different such as construction lead times and the level of capacity offered to the market.
- Offset is another type of financial instrument within an emissions control scheme, which is used to compensate for emissions. Common offset mechanisms include supporting forestation, carbon sequestration, renewable energy and energy efficiency projects. As with allowances, the level of offsets in a cap-and-trade program is limited. In our model, consideration of offsets (which are generally cheaper than penalties) would have allowed generators a cheaper means to comply with the cap.

- Recycling the revenue, collected from allowance auctions, among the consumers could mitigate the effect of the observed increase in electricity prices due to the cap-and-trade implementation. On the other hand, part of the revenue could be recycled to low-emission generators so that they can improve their competitiveness against fossil-fuel generators. One of the recent emissions control bills in the U.S. Congress ([23]) considers recycling 75% of the cap-and-trade revenue to consumers.
- Demand side management (DSM) strategies (e.g., smart meters, efficiency and consumption incentives) are intended to have an impact on the level and patterns of energy consumption, thereby, impacting total emissions. However, the inclusion of DSM strategies in our methodology would significantly increase the modeling challenge.

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