Cost of carbon emissions abatement in the
Ontario electricity market
2006 to 2011

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Abstract

The purpose of this paper is to estimate the cost of Ontario’s renewable energy policy in terms of its effect on carbon emissions. With this knowledge, the cost of carbon dioxide (CO₂) abatement in Ontario’s electricity market can be compared to CO₂ abatement cost data observed in other markets as a result of alternative strategies. Based on the assumption that renewable energy generation replaces coal-fuelled generation, the cost of CO₂ abatement is estimated to be $93/tonne, approximately one order of magnitude more than other CO₂ abatement programme costs in other markets/jurisdictions. If natural gas is the replaced fuel the cost is estimated to be $207/tonne.
1. **Purpose and scope of the study**

The issue of negative externalities associated with carbon emissions—including from electricity generators—has been faced by many political jurisdictions throughout the world. The government of Ontario has chosen a particular policy construct to deal with this issue. Given the large absolute magnitude of the resulting programme, the cost effectiveness of this policy is an important public policy question for Ontario.

The purpose of this paper is to estimate the cost of Ontario’s renewable energy policy in terms of its effect on carbon emissions. With this knowledge, the cost of carbon dioxide (CO\(_2\)) abatement in Ontario’s electricity market can be compared to CO\(_2\) abatement cost data observed in other markets as a result of alternative strategies. In undertaking this analysis, a structural model of Ontario’s wholesale electricity market is specified. A counterfactual policy related to the renewable energy programme is then formulated and used to obtain the desired estimates.

The paper proceeds as follows. In section 2, the structural model of Ontario’s electricity market is specified and estimated. A brief history of the market is also provided. The counterfactual policy is formulated to characterise the impact of Ontario’s renewable energy policy on the market in section 3. Section 4 concludes.

For a general discussion of issues related to electricity markets, see Stoft (2002), Wilson (2002), and Rothwell and Gomez (2003). For more additional detail and discussion related to Ontario’s electricity market, see Olmstead (2012).

2. **Ontario’s wholesale electricity market**

2.1. **Introduction**

A competitive wholesale electricity market began operation in Ontario in May 2002. The purpose of this market is to coordinate production and consumption of electricity
in Ontario—including inter-jurisdictional trade—in an economically efficient manner while maintaining electricity system reliability.² Prior to May 2002, the functions of what subsequently became the wholesale electricity market were fully integrated components of Ontario Hydro³—a vertically integrated, Province of Ontario crown corporation that managed the generation and transmission of electricity within Ontario, as well as all trade of electricity with neighbouring jurisdictions.

The purpose of a competitive wholesale market is to induce a process whereby optimal use of existing resources, including imports, is incentivised in the short run, while in the long run more efficient sources of supply would drive less efficient sources of supply out of the market. This process, in both time dimensions, is intended to be guided by market-determined prices. In the short run, supply would be drawn from the generating facilities with the lowest incremental cost of production and would be allocated to the consumers with the highest willingness-to-pay. Inter-jurisdictional trade of electricity would occur, subject to potentially binding transmission system constraints, largely as an arbitrage process whereby electricity would flow from jurisdictions with low prices to jurisdictions with high prices.⁴ In the long run, prices would guide producer and consumer decisions that are fixed in the short run.⁵

Under a standard competitive market construct, wholesale market clearing prices

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² One way to characterise the quality of electricity services is to consider the probability of their availability: the higher the probability, the higher the quality. System reliability refers to maintaining an arbitrarily high value of this characteristic. Since, in a specified jurisdiction, system reliability is both non-excludable and non-rivalrous in its provision and consumption, it is a public good.
³ The Electricity Act, 1998, abolished Ontario Hydro and replaced it with five distinct entities currently known as Ontario Power Generation Incorporated (OPG), Hydro One Incorporated (HOI), the Independent Electricity System Operator (IESO), the Ontario Electricity Financial Corporation (OEFC), and the Electrical Safety Authority (ESA). The OEFC is the legal successor company to Ontario Hydro.
⁴ The ranking of jurisdictions by price is anticipated to change through time.
⁵ Many characteristics of electricity producers and consumers are fixed in the short run. In the case of producers, these include facility size, location, and fuel type. In the case of consumers, these include location and structure of production facilities (consuming firms), and the choice of appliances and residence size (consuming households).
would vary through time in response to varying cost and demand conditions and all consumers and producers would pay or be paid, respectively, this price.\(^6\) With respect to producers, assuming that supply is offered into the market at incremental cost, this means that at any given point in time quasi-rents would be earned by infra-marginal suppliers while the marginal supplier would break even. This situation is illustrated in Figure II-1.\(^7\) Such quasi-rents, which would be larger in hours with higher prices, are necessary to cover fixed costs. In the long run, the composition of capacity would adjust such that these quasi-rents would exactly cover fixed costs. In practice, while quasi-rents would be earned by some producers at each point in time, there would be a small number of hours characterised by extremely high prices as a result of available supply being exhausted.\(^8\) It is in these hours that the bulk of fixed costs would be covered, including those of the marginal supplier—which would receive a price in excess of marginal cost since price would be determined based on willingness-to-pay. This situation is illustrated in Figure II-2.\(^9\)

This process envisioned a relatively minor role for regulators regarding the entrance of incremental supply. It was expected that regulators, acting under the authority of the provincial government, would provide various services—such as real-time management of the transmission system—critical to the ongoing operation of the electricity market by the establishment of an independent system operator. In Ontario, the relevant agency is the Independent Electricity System Operator (IESO).

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\(^6\) The issue of locational pricing is ignored in this paper. However, had this not been the case the general conclusions would remain intact, except that instead of viewing the Ontario as a single market with a uniform wholesale market clearing price it would be viewed as a set of potentially different sub-markets based on potentially binding physical constraints in the electricity transmission system.

\(^7\) The illustrations in this section assume generic upward- and downward-sloping market supply and demand functions. \(Q\) is the amount of generation capacity.

\(^8\) In Ontario, regulations prevent the absolute value of the wholesale market clearing price from exceeding $2,000 per MWh.

There are a variety of benefits associated with this type of market structure. Decentralised decision making incentivises a variety of supply and demand responses to changing cost and demand characteristics that cannot typically be made by
government-owned and managed monopolies. This is particularly the case in relation to inter-jurisdictional trade, where arbitrage-driven trade is likely to lead to market demand being satisfied at a lower total cost than otherwise. Competitive markets also tend to distribute risk efficiently. In particular, risk tends to be borne by shareholders of generation firms that choose to bear it rather than by electricity consumers (rate-payers) and government (tax-payers), who generally bear it under government-owned monopolies.

Structural reforms were necessitated by the rigidity of the industry in the years before market opening in 2002. Consumer prices, set by government regulation, generated insufficient revenues to cover the costs incurred by Ontario Hydro, thereby resulting in large accumulated losses. With respect to generation capacity, prior to market opening the most recent electricity generator to enter service was the fourth nuclear reactor at Darlington, east of Toronto. Taken together, low prices resulted in a lack of investment in the industry as Ontario Hydro lacked sufficient financial resources and no privately-owned firm had the incentive to propose entry.¹⁰

Over the period commencing with the passage of the *Electricity Act, 1998*, in that year and culminating with market opening in 2002, approximately 10,000 MW of incremental capacity—both greenfield (all of which was natural gas-fuelled) and refurbishments of previously exited capacity (all of which was nuclear-fuelled)—had announced plans to enter the market.¹¹ While it was not clear at the time how much of this proposed incremental capacity would ultimately enter, opening the market

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¹⁰ There was an analogous lack of investment in transmission infrastructure. One additional benefit of a competitive market is that it signals the locations (routes) of the most socially valuable transmission infrastructure improvements.

¹¹ See the first report of the Market Surveillance Panel, “Monitoring Report on the IMO-Administered Electricity Markets for the First Four Months,” published on 7 October 2002. Note that IMO is the
certainly induced much private-sector interest in doing so.

It was not immediately clear that the market process described above would fail to achieve the desired long-run equilibrium. However, in the years after market opening it became clear that realised wholesale market clearing prices were, on average, insufficiently high such that the desired long-run equilibrium would indeed not be achieved. This outcome obtained, at least partially, as a result of government and regulatory intervention. In particular, a variety of policies and regulations, some of which were highly technical in nature, had the effect of systematically suppressing the wholesale market clearing price paid by consumers to producers.

For instance, in the process of determining the wholesale market clearing price, electricity generators are treated as being able to change their level of output at a constant multiple of what is technically feasible.\textsuperscript{12,13} This policy was adopted as a means of reducing the volatility of the wholesale market clearing price, which it did by treating wholesale market supply as being effectively more price elastic (faster to adjust to a given price change) than is truly feasible. However, the effect was also to systematically suppress the average wholesale market clearing price.\textsuperscript{14} The effect is

\textsuperscript{12} The rate at which a particular electricity generator can change its level of output is a technical characteristic of the generator that is known as its ramp rate. For instance, suppose a generator requires 20 minutes to be able to increase its output from 100 MW to 200 MW, then its ramp rate, at least while increasing output over the specified range, is 5 MW per minute. The multiple of this rate that is used by the system operator in the wholesale market clearing price determination process can be thought of as the ramp rate multiplier. Continuing with the example above, if a 12-times multiplier is used by the system operator then the generator would be treated as being able to increase output at a rate of 60 MW per minute. In other words, the generator would be treated as being able to increase its output from 100 MW to 200 MW in 1 minute and 40 seconds rather than the 20 minute duration required physically.

\textsuperscript{13} From market opening on 1 May 2002 to 11 September 2007, the ramp rate multiplier was twelve (12). Effective 12 September 2007 onward, it was reduced to three (3).

\textsuperscript{14} This issue was discussed in the second report of the Market Surveillance Panel (MSP, December 2003, p. 112), many times subsequently, and elsewhere.
most meaningful at the most supply-constrained points of time, when the standard market construct described above suggests the bulk of fixed cost is recovered.

A similar example relates to the treatment of inter-jurisdictional trade—a treatment that systematically suppresses the wholesale market clearing price.\(^\text{15}\)

As a result of this outcome, a restructuring of the wholesale market began in 2004 with the passage of the *Electricity Restructuring Act, 2004*, which among other things, amended the *Electricity Act, 1998*. The key impact of this Act was the creation of the Ontario Power Authority (OPA).\(^\text{16}\) One aspect of the OPA’s mandate is to act as a long-run electricity system planner.\(^\text{17}\) To that end, recognising that entrance of new supply would eventually become necessary and that the market as described above would not achieve this on its own, the OPA initiated a programme of generation procurement—a programme of policy-induced entry of supply. At its beginning, this programme focused on inducing entry of natural gas-fuelled electricity generators so as to implement the government’s goal of withdrawing coal-fuelled electricity generators from the market.

Later, the mandate of the regulator was augmented to include the inducement of renewable energy generating technologies—principally wind- and solar-fuelled—into the electricity market.\(^\text{18}\) While this deepened the extent of government involvement in

\(^\text{15}\) This issue was discussed in the fourth report of the Market Surveillance Panel (MSP, December 2004, p. 17-8), many times subsequently, and elsewhere.


\(^\text{17}\) The OPA has numerous additional responsibilities, especially in relation to electricity conservation and usage efficiency. Consideration of these activities is beyond the scope of this paper.

\(^\text{18}\) For instance, a 16 November 2005 ministerial directive required the OPA to enter into contracts with nine wind-fuelled generation firms that had been selected by the Ministry of Energy to construct wind farms in Ontario.
the market, the structure of the hybrid market was not materially altered.

Due to the *Electricity Restructuring Act, 2004*, Ontario’s electricity market became a hybrid market: a competitive wholesale electricity market with a government agency that actively manages supply. One impact of this altered market structure is that, subsequent to its creation, no generation capacity has entered Ontario’s electricity market without a contract written under the generation procurement programme. Though the OPA is not a regulator in the classical sense, given its role in actively managing market supply, terminology referring to it as such is adopted herein.

Certain relevant details regarding the generation procurement programme are discussed in this section. However, it is immediately clear that any such programme may lead to costs being borne by the regulator.\(^{19}\) These costs, and the risks associated therewith, are funded through a financial account known as the global adjustment mechanism (GAM).\(^ {20}\) A convention of referring to aggregate costs, measured in dollars, borne by the regulator in month \(t\) as \(GAM_t\) is adopted.

Assuming that funding directly from the provincial treasury is not feasible, some mechanism is required to raise the necessary funds from electricity consumers, *i.e.*, the regulator’s budget must be balanced. The specific rule used to allocate GAM costs among consumers shall be referred to as the global adjustment allocation rule (GAAR). From its institution in January 2005, the GAAR was such that all Ontario-based consumers were charged in constant proportion to their own level of total monthly consumption. Export-consumers do not pay this fee. A convention of referring to the

\(^{19}\) As discussed below, the aggregate costs incurred may be negative. In such an event, this balance is paid out to consumers in an analogous manner to the mechanism that allocates positive costs.

\(^{20}\) As noted in the detailed discussion regarding the composition of the GAM below, GAM includes significant expenses related to regulatory activities other than the programme of generation procurement. For instance, GAM includes expenses associated with various regulator-directed conservation programmes.
rate, measured in dollars per kWh, at which costs are allocated by the regulator in month \( t \) as \( g_t \) is adopted. Interestingly, the GAAR was altered in an important manner effective January 2011. Given the recent nature of this change and the nature of the adjustment and learning process that will follow, this issue will not be considered in the main body of the section, though it is discussed at some length in Appendix II-A.

Had either the regulator’s generation procurement initiative or the GAAR been materially different, outcomes observed in Ontario’s electricity market would have been materially different. The purpose of this section is to assess the hypothetical impact of two such policy counterfactuals. First, the impact of renewable generation procurement is assessed. Second, the impact of altering the GAAR such that export demand is made subject to the costs associated with global adjustment is assessed.

The section will proceed as follows. Section 2.2 describes the methodology employed in this paper. Section 2.3 describes in some detail the structure of the wholesale electricity market and the regulator, with particular focus on the impact of policy-induced entrance of supply on the wholesale market equilibrium. Particular attention is paid to the aspects of the market for which hypothetical alternative policies are relevant. This discussion is used to motivate the components of a simultaneous equations model of Ontario’s electricity market. Section 2.4 describes the data. Section 2.5 describes the econometric techniques and econometric results associated with the estimation of the market model. Section 2.6 constructs a base case market equilibrium.

2.2. Methodology

As stated in section 2.1, the purpose of this section is to assess the impact on the electricity market equilibrium of a particular regulatory policy. Such an assessment would be made by determining the difference between the observed equilibrium and certain counterfactual policy equilibria.
The first step is to model the process by which the observed equilibrium obtains. This is called the base case. The second step is to consider the alternative processes by which each counterfactual policy equilibrium obtains. These processes are used to simulate the related counterfactual policy equilibrium, thereby determining the impact of the regulatory policy.

2.2.1. Step one: the base case

The model is comprised of a system of six equations—corresponding to six endogenously determined variables: Ontario-based supply; imports; Ontario-based demand; exports; the regulator’s budget constraint; and the quantity equilibrium—as specified in section 2.3 that describe, in simplified terms, the process by which the observed equilibrium obtains. As described there, the first four of these equations must be estimated, while the last two are identities. The four non-identities are estimated as a system of simultaneous equations, with techniques described in section 2.5. The regulator’s budget constraint must be calibrated with relevant market data.

The fully parameterised system of six equations is then solved for the base case values of each of the six endogenous variables. This process is discussed further in section 6.

2.2.2. Step two: the counterfactuals

Under each of the counterfactuals considered, at least one aspect of the market would have been different. Critically, the estimated coefficients are assumed to be unaltered. For instance, the estimated coefficient associated with the price paid by exporters of electricity is assumed to be unchanged as a result of the counterfactual policy.

The counterfactual-policy outcomes are constructed by altering either the underlying data series or the regulator’s budget constraint as appropriate. The equilibrium impact of each counterfactual policy is then measured by comparison of the simulated
counterfactual with the base case. These issues are considered in section 3.

2.3. The model: the role of the regulator and the wholesale market

The impact of regulatory policy on the wholesale market equilibrium is of paramount importance in this study. Section 2.3.1 outlines, with reference to Appendix II-A, the structure of the regulator. Particular attention is given to how its policies mandate the existence of a global adjustment mechanism (GAM) in principle. Section 2.3.2 outlines the structure of the wholesale market itself, including how the equilibrium wholesale market clearing price and global adjustment rate are determined. Attention is directed to the mechanisms by which regulatory intervention impacts the various components of the market, and therefore its equilibrium.

2.3.1. The role of the regulator

The government regulator that is relevant in the context of this paper is the one whose objective is to engage in long-run management of the supply side of Ontario’s electricity market: the OPA. To that end—under the direction and authority of numerous directives from the provincial government—the OPA initiated a programme of generation procurement. This programme manifested itself in the form of many specific procurement initiatives differentiated by generation technology or fuel source, such as nuclear, hydro, natural gas, and wind.21

The contracts that resulted from these procurement initiatives offered signatories terms and, therefore, outcomes that could not be obtained from uncontracted entrance into the wholesale electricity market. The most important effects were to reduce the uncertainty

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21 The structure of individual procurement initiatives varied across initiatives. For instance, the initial wind generation contracts followed from a request-for-proposals process, while all solar generation contracts resulted from individual firm applications to various standard offer processes. The details of these procurement structures are not relevant within the context of this study.
and, in some cases, raise the level of the net present value of the expected revenues of prospective entrants.\footnote{It is likely the case that a large proportion, if not all, of the supply that entered the market as a result of these contracts would not have entered otherwise.}

From the perspective of the OPA, in any given time period (typically, one month), an individual contract may result in a payment that may be either positive or negative. The aggregate payments to all contracted generation in any time period may, as a consequence of summation, be either positive or negative as well. These costs are allocated to certain groups of consumers as a component of the GAM.

The mechanism by which GA is allocated among consumers has important implications for the functioning of the wholesale electricity market. From its creation in January 2005\footnote{The GA is defined, for the period prior to January 2005, to be zero both in aggregate terms and as a rate.} until December 2010 GA costs were allocated among consumers in proportion to their consumption, \textit{i.e.}, GA was levied at a specific rate ($g_t$, $\$\text{ per MWh of consumption}$). The allocation mechanism was meaningfully altered as of 1 January 2011. The changes are described in Appendix II-A, but are otherwise ignored in this analysis for reasons given there.

The impact of the programme of policy-induced entry manifests itself in the wholesale electricity market in two forms. First, supply is greater than it would have otherwise been. Second, the costs imposed through the allocation of GA will impact net-of-GA willingness to pay for electricity. The details of these two effects on various components of the market, as well as market equilibrium, are discussed in the next section.

\subsection*{2.3.2. The wholesale market}

This section outlines the general structure of Ontario’s wholesale electricity market.
The model of Ontario’s electricity market is composed of six distinct equations relating to: (i) Ontario-based supply; (ii) imports; (iii) Ontario-based demand; (iv) exports; (v) the regulator’s budget constraint; and (vi) a quantity equilibrium condition.24

### 2.3.2.1. Supply

Supply is offered into Ontario’s wholesale electricity market by both Ontario-based generators and importers.

#### 2.3.2.1.1. Ontario-based supply

Ontario-based supply \( q_i \) relates to electricity produced within Ontario and is endogenously determined within the model. In particular, it does not include imports of electricity to Ontario.

Ontario-based generators produce electricity using a variety of different technologies and fuel sources, and operate under a variety of different contractual arrangements relative to the regulator. The regulator’s programme of generation procurement impacts wholesale market supply in two respects: offer quantities and offer prices.

The quantity of offers is impacted by the generation procurement programme because it results in generators offering supply that would otherwise not be in the market. In other words, if a generator would not have entered Ontario’s market in the absence of regulatory inducement, then the regulator’s activity will have raised the quantity of offered supply.

Regulator activities also impact the prices at which generators in the market offer

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24 There are important issues related to real-time management of the electricity market and the time periods in which certain electricity resources are scheduled. In particular, inter-jurisdictional trade is determined and fixed in advance of real time—in the so-called pre-dispatch period. Consideration of such issues is beyond the scope of this study.
supply. It is assumed that generators offer their production into the wholesale market at their private opportunity cost—which is directly affected by the contractual terms offered by the regulator, if any. Consider two examples. First, a generator operating without a contract will have an opportunity cost equal to its physical incremental cost of supply. It is expected to offer its supply at this price. A detailed discussion of the contract structures relevant to Ontario is provided in Appendix II-B. In short, contracts between the regulator and generators have important effects on supply offers.

Ontario-based electricity producers are paid the wholesale market clearing price \((p_t)\)—in addition to which some generators also receive contractually specified out-of-market payments as described above. Regardless of contract structure, offering below the wholesale market clearing price is a necessary and sufficient condition for receiving dispatch instructions to produce.\(^\text{25}\)

For some electricity producers the wholesale market clearing price is the critical variable considered in relation to supply offers. For instance, it is generally the case that coal-fuelled thermal generators desire to produce whenever the wholesale market clearing price exceeds their incremental cost. Certain other generators, natural gas-fuelled thermal generators in particular, operate under contracts that include significant lump-sum transfers that are reduced whenever the wholesale market clearing price exceeds their contractually specified incremental costs. The result is that such firms are exposed to wholesale market conditions and tend to produce more output when the wholesale market price is higher. It is expected that Ontario-based supply will be

\(^{25}\) Ontario’s electricity system operator determines two dispatch schedules. The first is the so-called constrained schedule, which minimises the total cost of meeting demand and accounts for all constraints relevant to the market. Physical dispatch instructions to generators are based on this schedule. The second is the so-called unconstrained schedule, which functions similarly but ignores all (Ontario) internal transmission constraints. While there is no economically sensible reason for any physical constraint to be ignored in the determination of prices, wholesale market prices are based on this schedule.
increasing in the wholesale market clearing price.

Presuming that firms exposed to the wholesale market clearing price—such as coal- and natural gas-fuelled generators—will produce whenever that price exceeds incremental cost, offers from Ontario-based electricity producers in the wholesale market will be dependent on the level of those incremental costs. A unitless fuel price index, denoted \( f_{\text{uel}} \) and constructed as the weighted average of Henry Hub natural gas and Central Appalachian coal prices, is taken as a proxy for incremental costs.\(^{26}\) Each commodity trades on the New York Mercantile Exchange. The associated prices are converted into Canadian currency. The weights used in the construction correspond to the relative amount of generation capacity installed in Ontario.\(^{27}\) The fuel price index is assumed to be determined exogenously of Ontario’s electricity market. Supply is expected to be decreasing in the level of the fuel price index.

There is a class of producers whose level of production is not dependent on the wholesale market price. Within this class there are three sub-classes: producers whose output is independent of price due to (i) contractual arrangements, (ii) technical

\(^{26}\) The Henry Hub is a major natural gas pipeline junction located in Louisiana, United States. Central Appalachia is a major coal-producing region in central part of the Appalachian Mountains, roughly centred on West Virginia. Certain coal-fuelled generators in Ontario—Nanticoke Generating Station and Thunder Bay Generating Station, both owned by the provincial crown corporation Ontario Power Generation—also use coal from the Powder River Basin, located in Montana and Wyoming, United States. The market for coal from the Powder River Basin is smaller, and the price less volatile, than that from Central Appalachia. The Ontario-based generators that use it tend to purchase it under long-term contract, thereby diminishing the importance of the market price from an opportunity cost perspective. These features suggest the price of Central Appalachian coal is relatively more important than the price of Powder River Basin coal.

\(^{27}\) For instance, if, in a given month \( t \), the amount of coal-fuelled generation capacity was double the amount of natural gas-fuelled generation capacity, the coal price would receive a weight of \( \frac{2}{3} \) and the price of natural gas would receive a weight of \( \frac{1}{3} \) in the construction of the fuel price index for that month. These weights have changed since market opening, reflecting the construction of new natural gas-fuelled generators and the decommissioning of incumbent (at the time of market opening) coal-fuelled generators. Since the fuel mix is largely a matter of public policy, the weights are assumed to be determined exogenously of the wholesale electricity market. Indeed, coal is currently planned to be completely eliminated as a fuel in Ontario as a result of provincial government policy.
generator characteristics, and (iii) environmental conditions.

At the level of a specific firm, contractual arrangements can result in a situation where output is independent of the wholesale market clearing price if the incentives created by the contract result in the wholesale market clearing price—or any other real-time market conditions—not entering the firm’s profit function. If the difference between the contract price and the physical incremental costs of supply is positive, the generator will perceive its opportunity cost of supply as being negative, that is, reducing supply by one unit will lead to a loss of contract revenue in excess of the physical incremental cost of supply. Therefore, a profit maximising firm will maximise production. Since, as discussed above, offering below the wholesale market price is a necessary and sufficient condition for being dispatched to produce, such generators will offer into the market at the lowest price allowed. In Ontario, this price is negative $2,000 per MWh. Such contractual arrangements can be referred to as fixed-price contracts and are the type of contracts under which renewable resource generators, non-utility generators (NUGs), and most nuclear generators operate in Ontario.

Another situation where output may be independent of the wholesale market clearing price is as a result of the technical characteristics of the generation technology. For instance, nuclear powered generators have relatively limited ability to vary their level of output when in operation and, as a result, tend to produce output at or near their maximum capacity whenever in operation. Following shutdown, such generation facilities often require several days before production can resume. As a result, output

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28 The most important renewable resource technology in use in Ontario today, aside from large-scale hydro, is wind power. Solar and, to a lesser extent, biomass resource generators have also been constructed in Ontario. In the case of wind and solar resource generators, profit maximisation by maximisation of output manifests itself as the generator producing output at the greatest feasible level given the quality of inputs, air movement and solar conditions respectively, available at each time. As noted subsequently, see the discussion of the situation where output levels are exogenously determined by environmental conditions.
tends to be independent of the wholesale market clearing price.\textsuperscript{29}

Finally, output will be independent of the wholesale market clearing price if its level is determined exogenously by environmental conditions. For instance, hydroelectric generators use elevated water as the variable input in their production process. While it is often the case that such generators can vary their production on an hour-by-hour basis in response to market conditions, aggregate generation on a monthly basis is principally a function of the amount of water available—a characteristic beyond the generator’s control. In addition to their contractual arrangements, wind and solar resource generators are additional examples that tend also to be characterised by having a level of output exogenously determined by environmental conditions.

Taken together, the electricity generators discussed immediately above—renewables, NUGs, nuclear, and hydro—constitute a class of electricity producers whose level of output is not dependent on the wholesale market clearing price. The production of this class of producers is often referred to as baseload generation ($\text{baseload}_t$). Higher levels of exogenously determined baseload generation are synonymous with greater supply. Therefore, it is expected that quantity supplied will be increasing in the quantity baseload generation.

Thus, the specification of the Ontario-based supply curve used in the model is

$$q_t^s = y_0 + y_1p_t + y_2fuel_t + y_3baseload_t + \varepsilon_{1t} \quad (\text{II-1})$$

### 2.3.2.1.2. Imports

In addition to Ontario-based supply, electricity exchanged in Ontario’s wholesale
market can originate outside of province \((q_i^t)\). Such supply constitutes imports of electricity with respect to Ontario, which are modelled separately from Ontario-based supply so as to avoid constraining the wholesale market clearing price to having the same marginal effect as it does on Ontario-based supply. As a result, imports are permitted to have a different price elasticity than Ontario-based supply. Imports of electricity to Ontario are endogenously determined within the model.\(^{30}\)

As with Ontario-based supply, imports are expected to be increasing in the wholesale market clearing price \((p_t)\). Given that arbitrage is a critical aspect of the nature of inter-jurisdictional trade, import supply is expected to be relatively more elastic than Ontario-based supply since traders are assumed to actively seek out the highest price jurisdictions in which to offer their power for sale, \(i.e.,\) traders can easily offer their electricity into other markets. Ontario-based suppliers, on the other hand, must offer their production into Ontario’s electricity market if they want to receive a production schedule, irrespective of where they intend their output to ultimately go.\(^{31}\) With data measured in levels and not logs, this feature need not imply anything about the magnitude of the coefficient associated with the wholesale market clearing price relative to its equivalent in the Ontario-based supply equation. Unlike exports, with imports there is no issue regarding global adjustment \((g_t)\).

Imports are also expected to be dependent on contemporaneous market conditions in neighbouring jurisdictions. As prices in neighbouring jurisdictions are assumed to be endogenous with respect to Ontario’s wholesale electricity market, such electricity prices cannot be used as a measure of the conditions prevailing in those markets.

\(^{30}\) Inter-jurisdictional trade of electricity is feasible in relation to New York, Michigan, Minnesota, Manitoba, and Quebec.

\(^{31}\) Generators are not allowed to inject power into the electricity system without being selected to do so by the electricity system operator. In other words, generators can only acquire physical transmission rights as a result of offering into the wholesale electricity market.
Instead, the quantity of electricity consumed in New York state (called the New York integrated load and denoted \((NY_L_t)\)) is used as a proxy for market conditions beyond Ontario. With respect to imports, it is expected that, ceteris paribus, higher levels of electricity consumption in New York will result in lower levels of imports to Ontario as electricity is likely to be more highly valued in New York than in Ontario under such circumstances.\(^{32}\)

Finally, electricity is often transmitted between two neighbouring jurisdictions using Ontario’s transmission system. The explicit linking of the import and export components of the associated transactions results in a so-called linked-wheel transaction. The Market Surveillance Panel (MSP, January 2009) reports that during the seven-month period January to July 2008 there were an unusually large number of linked-wheel transactions through Ontario.\(^{33}\) Since linked-wheel transactions have no net impact on inter-jurisdictional trade, they do not impact Ontario’s wholesale market clearing price. They do, however, impact gross imports (and exports) of electricity. To control for the temporary increase of such transactions, a dummy variable equal to one for the seven specified months of 2008 and zero otherwise—denoted \(linked_t\)—is included in the model.

Thus, the specification of the import equation used in the model is

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q_t = \delta_0 + \delta_1 p_t + \delta_2 NY_L_t + \delta_3 linked_t + \varepsilon_{2t}
\]  

\(^{32}\) A variety of alternative control variables for contemporaneous market conditions in neighbouring jurisdictions were considered. For instance, the market-determined price of electricity in New York was one such candidate. However, there is a collinearity issue between this price and Ontario’s wholesale market electricity price. The New York integrated load allows a less problematic indication of demand in New York to be obtained.

\(^{33}\) The Market Surveillance Panel (MSP, July 2008) reports that this issue emerged as a result of certain technical characteristics of electricity markets in the United States. The issue was resolved as a result of market rule changes enacted by the New York Independent System Operator in July 2008 (MSP, January 2009).
2.3.2.2. Demand

Demand for electricity in Ontario’s wholesale market arises from Ontario-based consumers and exporters.

2.3.2.2.1. Ontario-based consumers

Ontario-based demand \( q_t^d \) relates to electricity consumed within Ontario and is endogenously determined within the model. In particular, it does not include exports of electricity from Ontario.

Ontario-based consumers pay the market clearing price \( p_t \) as well as global adjustment \( g_t \) for each unit of consumption. Assuming that consumers respond to the all-in price rather than to its components, as far as price is concerned, consumers will respond to the sum of the market-clearing price and global adjustment \( p_t + g_t \). It is expected that Ontario-based demand will be decreasing in the all-in price. Both the market clearing price and global adjustment are endogenous variables in the model.\(^{34}\)

Given that indoor climate control—principally space heating and cooling—is one of the most important uses of electricity, consumption is likely to be dependent on ambient temperature. However, in general demand will be neither an increasing nor a decreasing function of temperature. Rather, the impact of a change in ambient temperature on quantity demanded will be dependent on the initial ambient

---

\(^{34}\) Households (and certain other classes of consumers) in Ontario are eligible to participate in the regulated price plan (RPP) designed by the Ontario Energy Board (OEB). Consumers enrolled in the RPP pay specified rates for electricity—either tiered or time-of-use as applicable—that are fixed in advance for six-month periods. The plan is designed to smooth the costs associated with electricity usage. These rates are set based on forecasts of wholesale market energy prices and global adjustment with the intent of recovering the market-determined costs of consumption. At their own discretion, consumers may opt-out of the RPP in favour of a variety of competitively determined alternative contract structures. The remaining RPP-enrolled consumers are expected to have the lowest elasticity of demand of any class of consumers in Ontario’s electricity market.
temperature. Thus, if the ambient temperature is relatively low, say 0°C, and assuming that consumers desire to heat a certain amount of space to a particular (higher) temperature, then an increase of the ambient temperature will reduce the amount of electricity required for space heating. Similarly, if the ambient temperature is relatively high, say 30°C, and assuming that consumers desire to cool a certain amount of space to a particular (lower) temperature, then an increase of the ambient temperature will raise the amount of electricity required for space cooling. For these reasons, demand will not be a monotonic function of temperature.

Given the description above regarding the impact of a change of ambient temperature on demand, it is reasonable to conclude that demand is increasing in the extent to which ambient temperature deviates—above or below—from a typical indoor temperature chosen by humans. The concept of a heating degree day ($HDD_t$) can be used to measure the magnitude by which the ambient temperature is below a specified threshold. Consider a threshold of 18°C. The HDD measure for any given day will be the greater of (i) 18°C less the average ambient temperature and (ii) zero. Thus, if the ambient temperature is less than 18°C, a 1°C decrease will correspond to one additional heating degree day, while if the ambient temperature is greater than 18°C, a 1°C decrease will correspond to no change in the number of heating degree days.

Analogously, the concept of a cooling degree day ($CDD_t$) can be used to measure the magnitude by which ambient temperature is above the specified threshold. Thus, if the ambient temperature is greater than 18°C, a 1°C increase will correspond to one additional cooling degree day, while if the ambient temperature is less than 18°C, a 1°C decrease of ambient temperature corresponds to a fractional HDD if the initial temperature is less than 19°C.

---

35 The first over-the-counter weather derivatives, based on this concept, were introduced in 1997. Various related weather futures and options on weather futures have been exchanged on the Chicago Mercantile Exchange since September 1999. For additional detail, see chapter 20 of Hull (2002).

36 A 1°C decrease of ambient temperature corresponds to a fractional HDD if the initial temperature is less than 19°C.
C increase will correspond to no change in the number of cooling degree days.\textsuperscript{37}

Monthly measures of HDD and CDD can be computed by summing the relevant daily HDDs and CDDs. It is expected that demand will be increasing in both measures. However, there is no reason to believe that the marginal effect of a one unit change of HDD will be the same as the marginal effect of a one unit change of CDD. Therefore, the two measures both appear independently in the demand equation.

Finally, consumption of electricity in Ontario is expected to be sensitive to the state of the macro economy in Canada and beyond. A broad measure of electricity-intensive economic activity is included in the model to control for this aspect of demand. The control variable adopted is the Institute for Supply Management’s (ISM) Manufacturing Supplier’s Delivery Index. This index measures deliveries of manufactured goods by producers located in the United States. To eliminate a potential endogeneity problem between this variable and Ontario-based demand, a one-month lag ($M_{t-1}$) is used in place of contemporaneous delivery index in the model.\textsuperscript{38}

\textsuperscript{37} Analogously for CDD—see the previous footnote.

\textsuperscript{38} Many alternative control variables exist that are sensitive to the state of the macro economy. For instance, the ISM also publishes an index called the Purchasing Managers’ Index. This index is based on data broader in nature than deliveries (and, therefore, the deliveries index). However, since electricity usage is relatively more important to manufacturers than to other commercial firms, the deliveries index is a broad measure of economic activity that is particularly important to the electricity industry. Other potential alternative control variables considered include direct measures of the amount of manufacturing output (in Ontario, Canada, and the United States, or beyond) or manufacturing capacity utilisation, at sector, subsector, industry group, and industry levels as defined by the North American Industry Classification System (NAICS). Use of manufacturing sector data yields generally similar results, suggesting a degree of robustness to the particular choice made. Use of the less aggregated measures of manufacturing yielded varying results. This is likely a result of industry-specific effects. For instance, data regarding the transportation equipment manufacturing subsector (NAICS 336) and its nested industry groups and industries can be significantly impacted by planned shutdowns (say, for annual maintenance) and various other idiosyncratic effects such as strikes that are not meaningful factors relevant to outcomes in Ontario’s electricity market. Industry-level analysis would be required to appropriately handle these issues. This is beyond the scope of the analysis undertaken in this paper. Aside from its broad-based nature, the price index used was chosen because it is a long-established
Thus, the specification of Ontario-based demand equation used in the model is

\[ q_{t}^d = \alpha_0 + \alpha_1(p_t + g_t) + \alpha_2HDD_t + \alpha_3CD_t + \alpha_4M_{t-1} + \epsilon_{3t} \]  

(II-3)

### 2.3.2.2.2. Exports

In addition to Ontario-based demand, electricity exchanged in Ontario’s wholesale market is also consumed outside the province \( q^e_t \). Such demand constitutes exports of electricity with respect to Ontario and is modelled separately from Ontario-based demand. The rationale for this choice is analogous to the treatment of imports. Exports of electricity from Ontario are endogenously determined within the model.

As with Ontario-based demand, exports are expected to be decreasing in the wholesale market clearing price \( p_t \). Given that arbitrage is a critical aspect of the nature of inter-jurisdictional trade, whereas Ontario-based demand is determined by local economic and environmental conditions in addition to the price, export demand is expected to be relatively more price elastic. With data measured in levels and not logs, this feature does need not imply anything meaningful about the magnitude of the coefficient associated with price relative to its equivalent in the Ontario-based demand equation.

Note that in the (base-) case described above, it is the wholesale market price alone—and not the wholesale market price plus global adjustment as in Ontario-based demand—that is relevant to exports. The reason is that exports of electricity from Ontario are not charged global adjustment.

Exports are also expected to be dependent on contemporaneous market conditions in neighbouring jurisdictions. The quantity of electricity consumed in New York state (called the New York integrated load and denoted \( NY_{L_t} \)) is used as a proxy of market measure of manufacturing activity, having first been calculated in 1948. For a detailed discussion of the price index, including its usefulness as an indicator of manufacturing-sector activity, see Koenig (2002).
conditions beyond Ontario. It is expected that, *ceteris paribus*, higher levels of electricity consumption in New York will result in higher levels of demand for exports of electricity from Ontario.

The dummy variable discussed in relation to imports concerning linked-wheel transactions is included in the specification of the export equation based on an analogous rationale.

Thus, the specification of the export equation used in the model is

\[ q_t^e = \beta_0 + \beta_1 p_t + \beta_2 NY_{-L_t} + \beta_3 linked_t + \varepsilon_{4t} \]  

**(II-4)**

**2.3.2.3. The regulator’s budget constraint**

The regulator’s operations began on 1 January 2005. Its purpose and objectives, along with other details, were described above. This section describes the budget constraint that binds on the regulator, which ensures that the costs incurred by the regulator in its activities are recovered from (certain) electricity consumers through the global adjustment mechanism.

**2.3.2.3.1. Revenues**

The regulator collects revenue by levying the GA fee \( g_t \) on Ontario-based demand \( q_t^d \). Regulator revenue is the product of these two variables.

During the period from market opening to 31 December 2004, before the regulator existed, global adjustment was not levied, i.e., \( g_t = 0 \), and consequently no revenues were obtained. This is accounted for in the modelling process.

The structure of the GA allocation mechanism was changed effective 1 January 2011. As a result of the change two classes of Ontario-based consumers arose: class A and
class B. This issue is considered further in Appendix II-A, but is ignored in the modelling process for two reasons. First, the vast majority of Ontario-based consumers (based on quantity demanded) are expected to be class B consumers for whom global adjustment will be calculated and levied in an unchanged manner, i.e., as a specific rate \( g_t \). Second, the new policy regime was only in place for the final six months/observations of the sample period and consumers were just beginning to adapt thereto.

Thus, the regulator’s revenues are

\[
Rev_t = g_t * q^d_t \tag{II-5}
\]

The discussion will return to the specification of equation (II-5) in relation to the counterfactual policies. In particular, under the counterfactual policy in which GA is applied to exports, it will be altered.

### 2.3.2.3.2. Expenses

As described in section 2.3.2.1.1 and Appendix II-B, significant expenses related to contractually specified out-of-market top-up payments to certain electricity generators are borne by the regulator. The regulator also bears significant expenses associated with a programme of conservation activities.

The equation for regulator expenses, reproduced from Appendix II-B, is

\[
Exp_t = q^\text{wind}_t * (p^\text{wind}_t - P_t) + q^\text{solar}_t * \text{solar\_capacity} * (p^\text{solar}_c - P_t)
+ q^\text{nugs}_t * (p^\text{nugs}_c - P_t) + q^\text{nuclear}_t * (p^\text{nuclear}_c - P_t) + q^\text{base\_hydro}_t * (p^\text{base\_hydro}_c - P_t)
+ \text{nat\_gas\_capacity}_t + \text{contingency}_t + \text{conservation}_t \tag{II-6}
\]

This equation calibrated as described in Appendix II-B is
Note that the specification outlined in equations (II-6) and (II-7) does not guarantee or require that out-of-market top-up payments be positive transfers of funds from the regulator to generators. If the wholesale market clearing price was high enough, elements of the regulator’s expenses could be negative, i.e., the top-up can act as a clawback mechanism.

In the period before the regulator existed—from market opening to 31 December 2004—it obviously incurred no expenses requiring recovery. This period corresponds to the period during which global adjustment was not levied as described in the immediately preceding section.

The structure of regulator expenses was not altered by the global adjustment reforms of 2010, as described in Appendix II-A.

2.3.2.3.3. Budget balance

The regulator is required to balance its budget, i.e., it must raise the same amount of revenue by choice of the global adjustment rate as it incurred as expenses carrying out its various activities. Therefore, equations (II-5) and (II-6) or, equivalently, equations (II-5) and (II-7), must be equal. Thus

$$\text{Rev}_t = \text{Exp}_t$$

Substitution yields

\[
\begin{align*}
\text{Exp}_t &= q_{t}^{\text{wind}} \cdot (135 - P_t) + q_{t}^{\text{solar}} \cdot 0.19 \cdot (420 - P_t) \\
&\quad + 1577 \cdot (75 - P_t) + q_{t}^{\text{nuclear}} \cdot (55 - P_t) + 1900 \cdot (33 - P_t) \\
&\quad + \text{nat}_\text{gas}_\text{capacity}_t + \text{contingency}_t + \text{conservation}_t
\end{align*}
\]
This is the equation that endogenises the GA rate. If the regulator’s expenses are positive (negative) in aggregate then the GA rate is positive (negative), i.e., GA collects (return) revenue from the specified set of consumers.

### 2.3.2.4. Equilibrium

For the wholesale electricity market to clear, quantity supplied must equal quantity demanded. Conceptually, this means that Ontario-based supply plus imports must equal Ontario-based demand plus exports. However, this condition must be adjusted to account for transmission losses associated with the transmission of electricity.

When electricity is transmitted across a transmission system, a fraction of what is dispatched does not arrive at its destination. For instance, some of the dispatched electricity is converted to heat and lost. The dispatched electricity that is lost is referred to as line losses and can be thought of as the transportation cost associated with transmitting electricity from its point of generation to its point of consumption. Line losses—denoted as $0 < L < 1$—are modelled as a constant fraction through time; a process sometimes referred to as iceberg transportation costs in other contexts. In particular, $L = 0.025$ is assumed, i.e., line losses constitute 2.5% of dispatched electricity.

Thus, the specification of the market clearing equilibrium condition in quantities in the model is

$$q_t^d + q_t^e = (1 - L) \cdot (q_t^s + q_t^l)$$  \hspace{1cm} (II-9)
2.4. Data and literature review

This section discusses the data used in the electricity market model estimated in this paper and summarises a few empirical findings regarding price elasticities that are reported in existing literature.

2.4.1. Data

This study uses monthly data observed over a 110 month period from May 2002 to June 2011, inclusive.

The six endogenously determined variables—wholesale market clearing price, global adjustment, Ontario-based supply, imports, Ontario-based demand, and exports—as well as the so-called all-in price, that is, the sum of the wholesale market clearing price and GA, are plotted in Figures II-3, II-4, and II-5. Summary statistics for these variables are reported in Table II-1. Summary statistics for the exogenous variables used in the econometric model are reported in Table II-2.

The two market-determined prices—the wholesale market clearing price and the GA rate—are illustrated in Figure II-3. It is apparent that at the regulator’s origin the GA was near zero and subsequently somewhat negative. This is consistent with the regulator’s generation procurement programme just being initiated. Over time, as the magnitude of regulatory activity increased, the costs funded by the GA increased. The creation of the GA appears to have stabilised the all-in price (which, before the creation of the GA was the wholesale market price itself). The seasonal character of Ontario-based demand—with local peaks in both the summer and the winter, with spring and fall shoulder seasons, all of which is largely driven by average air temperature—is

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39 Other regulatory programmes, such as various conservations initiatives, began simultaneously. See Appendix II-B for additional detail.
illustrated in Figure II-4. Figure II-4 also reveals the magnitude of net exports, which is the difference between Ontario-based supply and demand.

The individual components of net exports—imports and exports—are illustrated in Figure II-5. Over the 110 month study period, Ontario was generally a net exporter, with average net exports averaging approximately 350 MWh per hour. During the period shortly after market opening, Ontario was, on average, a net importer of electricity. During the last 24 months of the study period net exports averaged approximately 1,070 MWh per hour. The long-run trend towards exporting more, importing less, and consequently having higher net exports is clear from these data as well as Figure II-5. This trend is driven, at least partially, by the general decline of the wholesale market clearing price—which is the price paid (received) by (for) exports (imports). It is this long-run trend that motivates interest in the counterfactual policy under which the GA rate would be applied to exports.

The data regarding New York integrated load results from a market process similar—though different in many important respects—to Ontario’s for the full duration of the study period. Note that the opening of New York’s wholesale electricity market predates Ontario’s.

Electricity market data were obtained from the Independent Electricity System Operator (IESO), Ontario Power Authority (OPA), and Ontario Energy Board (OEB). Canadian weather data are from Environment Canada. Natural gas and coal prices are from the United States Energy Information Administration (US EIA), converted to Canadian

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40 This statement ignores the role of intertie congestion, which when present creates a wedge between the internal and external Ontario electricity prices. This issue, and the related issue of the market for financial transmission rights (FTR), is addressed by Olmstead (2012). The full impact of the regulator’s activities depends on outcomes in that market and is critically dependent on whether FTR auction markets are efficient, i.e., characterised by forward market unbiasedness or not.
Figure II-3: Wholesale market price, global adjustment, and the all-in price

Figure II-4: Ontario-based demand and supply
currency using the last exchange rate observation for the month, as recorded by the Bank of Canada. The Institute for Supply Management’s Manufacturing Supplier Delivery Index was obtained from the Federal Reserve Economic Data (FRED) database maintained by the Federal Reserve Bank of St. Louis.
2.4.2. Previous estimates of price elasticities

There is a voluminous literature associated with the analysis of electricity markets. While much of this work was motivated by the desire to undertake policy analysis, since this section is focused on the development of a model of Ontario’s electricity market in its own right—with policy analysis to follow in section 3—a small subset of this literature is considered here. In particular, attention here is paid to the results of previous empirical investigations of the price elasticities of the various components of the market. It is to these investigations that the empirical results derived later in this section can be compared.

Estimation of the price elasticity of demand for electricity has been carried out on many occasions. Taylor (1975) emphasised the importance of distinguishing between the short and long run in the context of electricity demand. Given the focus of this paper, attention here is paid to short-run analyses.

One early analysis of electricity demand was reported by Houthakker (1951), in which data for the years 1937 and 1938 from 42 municipalities in the United Kingdom were analysed. The price elasticity of demand was reported to be -0.9. Subsequent analysis by Houthakker and Taylor (1970) estimated the price elasticity on a state-by-state basis in the United States, with results ranging from -1.58 to -0.05 and an average in the
inelastic range. Additional analyses in the early literature include Baxter and Rees (1968), Wilson (1971), Anderson (1973), Griffin (1974), Houthakker, Verleger, and Sheehan (1973), and Mount, Taylor, and Tyrrell (1973). By the time of Taylor (1975), it had become a stylised fact that electricity demand is inelastic, and more so in the short run than in the long run.

Many additional analyses of electricity demand have been conducted since the 1970s. A number of surveys of this literature have also been conducted. Among these surveys are Bohi and Zimmerman (1984), Espey and Espey (2004), Reiss and White (2005), and Lijesen (2007). Estimates of price elasticity in these surveys vary considerably, though most are within the range -0.4 to -0.1, with an average of -0.2.

There is a significant and growing literature associated with the estimation of price elasticity of supply, especially in relation to analysis of renewable portfolio standards—policy instruments intended to incentivise entrance and utilisation of renewable generation capacity into electricity markets. For an example of this literature, see Johnson (2010). However, the characteristics of electricity supply in a given jurisdiction are at least somewhat dependent upon underlying geographic characteristics, such as the endowment of hydroelectric resources. Compared to Ontario, jurisdictions such as Quebec, British Columbia, and Norway are endowed with relatively significant hydroelectric resources, while jurisdictions such as Alberta, Texas, and Australia lack them almost completely. As a result, estimates of price elasticity of supply are less comparable across space than are estimates of price elasticity of demand.

Inter-jurisdictional trade of electricity has been much less widely studied. The basic rationale for such trade is to arbitrage spatial price differences, with electricity flowing from low-price to high-price jurisdictions. Borenstein, Bushnell, and Wolak (2002)

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41 Alaska and Hawaii were excluded.
explicitly accounts for the role of imports in its study of the Californian electricity market over the years 1998 to 2000, but does not explicitly undertake measurement of their price responsiveness. Mansur (2003) estimates the price elasticity of net imports to range between 0.79 and 4.20 depending on the time of day, for the Pennsylvania-New Jersey-Maryland (PJM) market. IESO (2008) estimates the price elasticity of exports from Ontario to New York to range between -5.65 and -2.79 depending on the time of day, with an average of -4.67.

Taken together, the literature suggests that demand is substantially less price responsive than is inter-jurisdictional trade.

2.5. Estimation and results

Each estimable equation is specified as a linear relationship of the variables as discussed above. Months are indexed with the subscript \( t \). All 110 observations (months) are used in the estimation of each estimable equation.

2.5.1. Estimation technique and estimates

Each of the four estimable equations has one regressor—the relevant price—that is endogenously-determined. The equations, therefore, cannot be consistently estimated with the standard ordinary least squares estimator. Instead, the four estimable equations are estimated by a generalised method of moments instrumental variables (GMM IV) estimator with heteroskedasticity and autocorrelation consistent standard errors. The instruments used in each equation are the excluded exogenous variables that appear in the other estimable equations of the system.

Econometric results associated with the estimation of equations (II-1), (II-2), (II-3), and (II-4) are reported in the four panels, A, B, C, and D, respectively, of Table II-3. The F-statistic associated with the appropriate first-stage regression and the J-test of over-
identifying restrictions is also reported in the various panels of Table II-3.

These results were generated by use of Stata/SE 11.0 for Windows.

2.5.2. Discussion

Before turning to a discussion of the coefficient estimates, the relevance and validity of the instruments used are considered. There are two basic requirements that an instrumental variable must satisfy: it must be correlated with the endogenous variable and orthogonal to the (unobservable) error process. The first-stage F-statistic and the J-statistic can be used to consider these requirements. Each estimable equation is considered separately.

The first-stage F-statistic provides a useful rule-of-thumb regarding the assessment of the strength of the instruments employed, that is, whether the instruments used are meaningfully correlated with the endogenous variable—of which there is one in each estimable equation. Weak instruments result, at best, in misleading inference. Indeed, sufficiently weak instruments may function no better than randomly generated instruments. This point was made by, for instance, Bound, Jaeger, and Baker (1995) regarding Angrist and Krueger’s (1991) study of returns to education and is an issue that must be considered here. Stock, Wright, and Yogo’s (2002) discussion of weak instruments in the context of GMM concludes that when the first-stage F-statistic is less than 10 that it is prudent to use an estimation method fully-robust to instrument weakness instead of GMM. However, of the four estimable equations considered here, the smallest first-stage F-statistic—approximately 63, from Table II-3 Panel C—is well above the threshold referred to by Stock, Wright, and Yogo (2002).

Hansen’s (1982) J-statistic can be used to assess an instrument’s independence from the (unobservable) error process. This test can be used if an equation is overidentified—
Table II-3: Panel A: Estimation of Ontario-based Supply Equation

<table>
<thead>
<tr>
<th>Variable</th>
<th>Coefficient</th>
<th>z-statistic</th>
<th>p-value</th>
</tr>
</thead>
<tbody>
<tr>
<td>$p_t$</td>
<td>110.14</td>
<td>30.11</td>
<td>0.000</td>
</tr>
<tr>
<td>$fuel_t$</td>
<td>-689.10</td>
<td>-10.53</td>
<td>0.000</td>
</tr>
<tr>
<td>$baseload_t$</td>
<td>1.023</td>
<td>35.19</td>
<td>0.000</td>
</tr>
<tr>
<td>$Constant$</td>
<td>-68.62</td>
<td>-0.15</td>
<td>0.881</td>
</tr>
</tbody>
</table>

First-stage F-statistic (with p-value) 129.00 (0.0000)
J-statistic (with p-value) 1.6674 (0.8930)

Table II-3: Panel B: Estimation of Import Equation

<table>
<thead>
<tr>
<th>Variable</th>
<th>Coefficient</th>
<th>z-statistic</th>
<th>p-value</th>
</tr>
</thead>
<tbody>
<tr>
<td>$p_t$</td>
<td>20.29</td>
<td>17.52</td>
<td>0.000</td>
</tr>
<tr>
<td>$NY_L_t$</td>
<td>-0.044</td>
<td>-5.27</td>
<td>0.000</td>
</tr>
<tr>
<td>$linked_t$</td>
<td>723.19</td>
<td>22.12</td>
<td>0.000</td>
</tr>
<tr>
<td>$Constant$</td>
<td>612.97</td>
<td>6.14</td>
<td>0.000</td>
</tr>
</tbody>
</table>

First-stage F-statistic (with p-value) 200.43 (0.0000)
J-statistic (with p-value) 1.6508 (0.8950)

Table II-3: Panel C: Estimation of Ontario-based Demand Equation

<table>
<thead>
<tr>
<th>Variable</th>
<th>Coefficient</th>
<th>z-statistic</th>
<th>p-value</th>
</tr>
</thead>
<tbody>
<tr>
<td>$p_t + g_t$</td>
<td>-84.55</td>
<td>-8.94</td>
<td>0.000</td>
</tr>
<tr>
<td>$HDD_t$</td>
<td>190.69</td>
<td>46.82</td>
<td>0.000</td>
</tr>
<tr>
<td>$CDD_t$</td>
<td>907.54</td>
<td>60.99</td>
<td>0.000</td>
</tr>
<tr>
<td>$M_{t-1}$</td>
<td>19.39</td>
<td>7.27</td>
<td>0.000</td>
</tr>
<tr>
<td>$Constant$</td>
<td>17,607.3</td>
<td>34.94</td>
<td>0.000</td>
</tr>
</tbody>
</table>

First-stage F-statistic (with p-value) 63.02 (0.0000)
J-statistic (with p-value) 1.7740 (0.7772)

Table II-3: Panel D: Estimation of Export Equation

<table>
<thead>
<tr>
<th>Variable</th>
<th>Coefficient</th>
<th>z-statistic</th>
<th>p-value</th>
</tr>
</thead>
<tbody>
<tr>
<td>$p_t$</td>
<td>-21.71</td>
<td>-12.63</td>
<td>0.000</td>
</tr>
<tr>
<td>$NY_L_t$</td>
<td>0.122</td>
<td>14.05</td>
<td>0.000</td>
</tr>
<tr>
<td>$linked_t$</td>
<td>1717.42</td>
<td>33.13</td>
<td>0.000</td>
</tr>
<tr>
<td>$Constant$</td>
<td>325.67</td>
<td>2.84</td>
<td>0.004</td>
</tr>
</tbody>
</table>

First-stage F-statistic (with p-value) 200.43 (0.0000)
J-statistic (with p-value) 1.7522 (0.8823)
which is true of each of the estimable equations. The null hypothesis is jointly that the instruments are orthogonal to the error and the model is correctly specified. A rejection of the null hypothesis implies that either the instruments do not satisfy the orthogonality condition or the model was misspecified. Such a result implies that either the instruments are not exogenous or were wrongly excluded from the regression. As reported in the various panels of Table II-3, the null hypothesis is not rejected in relation to any of the four estimable equations.

These results, taken together, afford confidence in both the model specifications and instruments chosen. With respect to the coefficient estimates, with the exception of the constant in the Ontario-based supply equation, all coefficient estimates differ statistically from zero in the directions described in section 2.3.

The coefficient estimate associated with the wholesale market clearing price in the equations for Ontario-based supply and imports are both positive and statistically significant. In other words, each of these curves is upward-sloping. In particular, ceteris paribus, a $1 per MWh increase of the wholesale market clearing price corresponds to a 110 MWh per hour increase in Ontario-based supply and a 20 MWh per hour increase in imports. On the other hand, the coefficient estimates associated with the price paid by consumers—the wholesale market clearing price plus global adjustment in the case of Ontario-based demand, and the wholesale market clearing price alone in the case of exports—are both negative and statistically significant. In other words, each of these curves is downward-sloping. In particular, ceteris paribus, a $1 per MWh increase of the relevant price paid by consumers corresponds to an 85 MWh per hour decrease in Ontario-based demand and a 22 MWh per hour decrease in exports.

With respect to the Ontario-based supply equation, the coefficient estimate associated with the fuel price index—constructed using the coal and natural gas prices—is
negative and statistically significant. This indicates that increased costs of generation have a negative marginal effect on market supply. The coefficient estimate associated with baseload generation is positive and statistically significant. This indicates that increased generation from generally non-price responsive generators increases supply.

With respect to the Ontario-based demand equation, the coefficient estimates associated with the temperature variables—HDD and CDD—are positive and statistically significant. This indicates that demand is increasing in the extent to which ambient temperature deviates from 18°C, the baseline adopted in section 2.3. The relationship between these two variables, as well as the coefficient estimates themselves, is discussed in further detail below. The coefficient estimate associated with the manufacturing activity index is also positive and statistically significant. This indicates that demand is greater when there is greater manufacturing activity.

With respect to the imports equation, the coefficient estimate associated with the New York integrated load variable is negative and statistically significant. This indicates that greater consumption of electricity in New York results in fewer imports to Ontario, a result due to less electricity being available for export from New York at any given price when New York demand is relatively high. The coefficient associated with the dummy variable related to the period—the first seven months of 2008—in which the volume of linked-wheel transactions was notably high is both positive and statistically significant. The point estimate indicates that the average volume of extraordinary linked-wheel transactions scheduled either through Ontario or ending in Ontario (thus, import-only) was approximately 723 MWh per hour during the period. This represents approximately 44% of the average 1655 MWh per hour of imports observed during the seven-month period.

With respect to the exports equation, the coefficient estimate associated with the New
York integrated load variable is positive and statistically significant. This indicates that greater consumption of electricity in New York results in greater exports from Ontario, a result due to more electricity being demanded in New York at any given price when New York consumption is relatively high. This effect is, as expected, opposite that found in relation to imports. The coefficient associated with the dummy variable related to extraordinary levels of linked-wheel transactions is both positive and statistically significant. The point estimate indicates that the average volume of extraordinary linked-wheel transactions scheduled either through Ontario or beginning in Ontario (thus, export-only) was approximately 1,718 MWh per hour during the period. This represents approximately 58% of the average 2,974 MWh per hour of exports observed during the seven-month period.

It was noted above that the coefficient estimates associated with the temperature variables—HDD and CDD—in the Ontario-based demand equation were both positive and statistically significant. The coefficient estimates are 190.69 and 907.54, respectively. These values indicate that a 1°C decrease in the ambient temperature below a threshold of 18°C, that is, a one-unit increase of the HDD, increases average demand by approximately 191 MW h per hour. Similarly, a 1°C increase in the ambient above a threshold of 18°C, that is, a one-unit increase of the CDD, increases average demand by approximately 908 MW h per hour. (Recall that the data are monthly averages.) In other words, demand increases by an average of 191 MWh per hour when ambient temperature falls by 1°C if it is relatively cold outside. Likewise, demand increases by an average of 908 MWh per hour when ambient temperature increases by 1°C if it is relatively warm outside. This reflects, to some extent, the use of electricity to power space-heating and -cooling equipment.

It is notable that the marginal effect on Ontario-based demand due to a change in ambient temperature seems to depend on the level of the ambient temperature. That is,
the marginal effects associated with the HDD and CDD variables are different. Whether this apparent difference is statistically significant in nature can be assessed with a chi-square test. The test results indicate that it is indeed the case that the marginal effects differ, with the marginal effect of a $1^\circ$ C increase in the ambient temperature when it is relatively warm outside being approximately five times greater than the marginal effect of a $1^\circ$ C decrease in the ambient temperature when it is relatively cold outside. The relatively large impact of a change of ambient temperature when it is relatively warm outside reflects the lack of substitutes to electricity that are available to power space-cooling equipment compared to space-heating equipment. In particular, space-cooling air conditioners are generally powered with electricity, while space-heating heaters can be powered with electricity as well as fossil fuels such as natural gas and propane. Indeed, according to data from the Office of Energy Efficiency, Natural Resources Canada, electricity powered between 13.1% and 15.4% of space-heating equipment in Ontario during the years 2003 through 2009, inclusive (NRC, 2011, Table 5).

2.5.3. Price elasticity estimates

The econometric results can be used to estimate the price elasticities associated with each of the four endogenously-determined quantities. The absolute values of these estimates are reported in Table II-4.

The point estimate of price elasticity of demand is 0.301. This falls within the range of estimates reported in the existing literature, as summarised in section 2.4.2. As discussed in section 4.2, estimates of price elasticity of supply are not directly comparable across jurisdictions.

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42 The null hypothesis $H_0: \alpha_2 = \alpha_3$ is tested against the alternative hypothesis $H_0: \alpha_2 \neq \alpha_3$. The test-statistic is distributed as a chi-square variable with one degree of freedom. The calculated test-statistic value is 2,315.92, with a related p-value of 0.0000. As a result, the null hypothesis can be rejected.
Table II-4: Price Elasticity Estimates

<table>
<thead>
<tr>
<th>Equation</th>
<th>Estimate</th>
<th>Std. Dev.</th>
</tr>
</thead>
<tbody>
<tr>
<td>(1) Ontario-based supply</td>
<td>0.307</td>
<td>0.082</td>
</tr>
<tr>
<td>(2) Imports</td>
<td>1.103</td>
<td>0.158</td>
</tr>
<tr>
<td>(3) Ontario-based demand</td>
<td>0.301</td>
<td>0.064</td>
</tr>
<tr>
<td>(4) Exports</td>
<td>0.976</td>
<td>0.870</td>
</tr>
</tbody>
</table>

The point estimates of price elasticity of imports and exports are 1.103 and 0.976, respectively. Each of these estimates fall within the range of estimates of price elasticity of net imports reported by Mansur (2003), as discussed in section 2.4.2. This suggests that the character of inter-jurisdictional trade between Ontario and its neighbours is not fundamentally different than that of California and its neighbours.

These data report that import supply is greater than three times (1.103/0.307 = 3.59) as price elastic as Ontario-based supply and that export demand is also greater than three times (0.976/0.301 = 3.25) as price elastic as Ontario-based demand. Thus, inter-jurisdictional trade is far more price responsive than Ontario production and consumption, a result consistent with the view that inter-jurisdictional trade is driven by arbitrage. It is also notable that Ontario-based supply is approximately as price elastic as Ontario-based demand (0.307 and 0.301, respectively).

The price elasticity of Ontario-based supply, $\varepsilon_t^s$, was calculated for each month as

$$\varepsilon_t^s = \frac{\gamma_1 p_t}{q_t(p_t)}$$

where the denominator is equation (1)—the Ontario-based supply equation—evaluated at the observed wholesale market clearing price. The mean of this series, $\bar{\varepsilon}$, is reported in Table II-4. The other price elasticities were calculated analogously, noting that in the case of Ontario-based demand the relevant price in the wholesale market clearing price plus the global adjustment rate.

Elasticities are reported in absolute value terms.

These results are particularly important in relation to a counterfactual policy discussion regarding the application of global adjustment to exports that is reported in Olmstead (2012).
2.6. Fitted base case

This section undertakes the fitting of the market equilibrium using the system of equations and econometric estimates reported in previous sections. This is the so-called base case. Section 2.6.1 describes the process by which the base case equilibrium is constructed. Section 2.6.2 reports results related to the base case, while section 2.6.3 provides related discussion.

2.6.1. Procedure

This section provides an explanation of how the four estimable equations of the model—Ontario-based supply, imports, Ontario-based demand, and exports—are combined with the two identities of the model—the quantity equilibrium condition and the regulator’s budget constraint—to determine equilibrium. This explanation is accompanied by a technical description of the analytical solution to the system of equations in Appendix II-C.

The specification for Ontario-based supply adopted in section 2.3.2.1.1 is

$$q_t^s = \gamma_0 + \gamma_1 p_t + \gamma_2 fuel_t + \gamma_3 baseload_t + \varepsilon_{1t}$$  \hspace{1cm} (II-1)

Given that the exogenous explanatory variables—the fuel price index and the amount of baseload generation—vary on a month-to-month basis, the component of the Ontario-based supply equation that is independent of the wholesale market clearing price can be represented, for month \( t \), as

$$q_{0t} = \gamma_0 + \gamma_2 fuel_t + \gamma_3 baseload_t$$  \hspace{1cm} (II-10)

Substitution of equation (II-10) into equation (II-1) yields

$$q_t^s = q_{0t} + \gamma_1 p_t + \varepsilon_{1t}$$  \hspace{1cm} (II-11)
Econometric estimates of the coefficients in equation (II-1) were reported in section 2.5.1. These estimates, in addition to the fuel price index and baseload generation data series, can be used to construct equations (II-10) and (II-11), yielding a fitted equation for Ontario-based supply.

**Figure II-6: Base case Ontario-based supply**

\[ q_t^s = \hat{\gamma}_{0t} + \hat{\gamma}_1 p_t \]  

\( \text{slope} = \frac{1}{\hat{\gamma}_1} \)
This equation, referred to as base case Ontario-based supply in order to facilitate discussion of the policy counterfactuals, is illustrated in Figure II-6. The graphical characterisation of equation (II-12), the function’s positive slope and negative vertical intercept in particular, correspond with the discussion provided in section 2.3.2.1.1 and the econometric results reported in section 2.5.1.

The specification for imports adopted in section 2.3.2.1.2 is

\[ q^I_t = \delta_0 + \delta_1 p_t + \delta_2 NY L_t + \delta_{linked} t + \epsilon_{2t} \]  \hspace{1cm} (II-2)

Similarly to Ontario-based supply, define

\[ \delta_{0t} = \delta_0 + \delta_2 NY L_t \]  \hspace{1cm} (II-13)

\[ q^i_t = \delta_{0t} + \delta_1 p_t + \epsilon_{2t} \]  \hspace{1cm} (II-14)

and

\[ \hat{q}^i_t = \delta_{0t} + \delta_1 p_t \]  \hspace{1cm} (II-15)

Equation (II-15), referred to as base case import supply in order to facilitate discussion of the policy counterfactuals, is illustrated in Figure II-7. The graphical characterisation of equation (II-12), the function’s positive slope and positive vertical intercept in

\[ \text{Figure II-7: Base case import supply} \]
particular, correspond with the discussion provided in section 2.3.2.1.2 and the econometric results reported in section 2.6.1. In addition, since (gross) imports must be non-negative, at prices below \((-\hat{\delta}_o/\hat{\delta}_1\)) import supply is zero.

Aggregate market supply is the sum of Ontario-based supply and imports. Using the econometric results reported in section 2.6.1., it can be written as the sum of equations (II-12) and (II-15). That is

*Figure II-8: Base case aggregate supply*
\[ \hat{Q}_{t}^{AS} = \hat{q}_{t}^{S} + \hat{q}_{t}^{I} = \hat{\gamma}_{o} + \hat{\delta}_{o} + (\hat{\delta}_{1} + \hat{\gamma}_{1})p_{t} \]  

Equation (II-16), referred to as base case aggregate supply, is illustrated in Figure II-8.

Base case aggregate demand is the solid line. The graphical characterisation of equation (II-16), the function’s positive slope and negative vertical intercept in particular, correspond with the discussion provided in sections 2.3.2.1.1 and 2.3.2.1.2 as well as the econometric results reported in section 2.6.1.

As noted above in the description of base case import supply, at prices below \((-\hat{\delta}_{o}/\hat{\delta}_{1})\) import supply is zero.\(^{45}\) In other words, at prices below \((-\hat{\delta}_{o}/\hat{\delta}_{1})\) aggregate base case supply is comprised of Ontario-based supply only. With respect to Figure II-8, this feature corresponds to base case aggregate supply being the dash-dot line at prices below \((-\hat{\delta}_{o}/\hat{\delta}_{1})\). This feature is not reflected in the mathematical representation of base case aggregate supply. This would be problematic if the wholesale market clearing price in any month \(t\) was ever less than \((-\hat{\delta}_{o}/\hat{\delta}_{1})\). This turns out not to be the case. The reason is that the fitted value of (gross) imports would be negative, thereby violating the non-negativity assumption.\(^{46}\)

The specification for Ontario-based demand adopted in section 3.2.1.3 is

\[ q_{t}^{d} = \alpha_{0} + \alpha_{1}(p_{t} + g_{t}) + \alpha_{2}HDD_{t} + \alpha_{3}CDD_{t} + \alpha_{4}M_{t-1} + \varepsilon_{3t} \]  

Similarly to Ontario-based supply and imports, define

\[ \alpha_{0t} = \alpha_{0} + \alpha_{2}HDD_{t} + \alpha_{3}CDD_{t} + \alpha_{4}M_{t-1} \]  

\[ q_{t}^{d} = \alpha_{0t} + \alpha_{1}(p_{t} + g_{t}) + \varepsilon_{3t} \]  

\(^{45}\) Note that \((-\hat{\delta}_{o}/\hat{\delta}_{1})\) varies on a month-to-month basis.

\(^{46}\) If the wholesale market clearing price was ever less than \((-\hat{\delta}_{o}/\hat{\delta}_{1})\) in a given month, the simulation procedure would have to explicitly recognise this outcome and set (gross) imports to zero. As noted in the main text, this turns out not to be necessary.
and

\[ q^d_t = \hat{a}_0 + \hat{a}_1(p_t + g_t) \]  

Equation (II-19), referred to as base case Ontario-based demand, is illustrated in Figure II-9. The graphical characterisation of equation (II-19), the function’s negative slope and positive intercept in particular, correspond with the discussion provided in section 2.3.2.1.3 and the econometric results reported in section 2.6.1.

The critically important feature of Figure II-9 is its illustration of the impact of the GA rate on observed demand. The gross-of-GA demand curve, based in principle on willingness-to-pay, is the dashed line while the net-of-GA demand curve, which is observed in the wholesale electricity market, is the solid line, both of which possess the same slope. The vertical distance between the two lines is the GA rate, meaning that the slopes are the same. The particular situation illustrated in Figure II-9 presumes a positive GA rate, that is, a GA rate that constitutes a charge to Ontario-based consumers of electricity. This is not the only possible case. As reported in Table II-1 in section 2.5, throughout its existence the GA rate has been both positive and negative. A negative GA rate would constitute a rebate to Ontario-based consumers and would be associated with the net-of-GA demand curve being located above the gross-of-GA demand curve in a diagram analogous to Figure II-9. In any event, the equilibrium GA rate is endogenously determined within the electricity market.

The specification for exports adopted in section 2.3.2.1.4 is

\[ q^e_t = \beta_0 + \beta_1 p_t + \beta_2 NY \_ L_t + \beta_3 linked_t + \varepsilon_{4t} \]  

Similarly to the other estimable equations, define

\[ \beta_{0t} = \beta_0 + \beta_2 NY \_ L_t \]  

(II-20)
Equation (II-22), referred to as base case export demand, is illustrated in Figure II-10.
The graphical characterisation of equation (II-22), the function’s negative slope and positive intercept in particular, correspond with the discussion provided in section 2.3.2.1.4 and the econometric results reported in section 2.6.1. In addition, since (gross) exports must be non-negative, at prices in excess of \((- \frac{\beta_{ot}}{\beta_1}\) ) export demand is zero. In other terms, \((- \frac{\beta_{ot}}{\beta_1}\) ) is the choke price of export demand.

Aggregate market demand is the sum of Ontario-based demand and exports. Using the econometric results reported in section 2.6.1, it can be written as the sum of equations (II-19) and (II-22). That is

\[
\hat{Q}_t^{AD} = \hat{q}_t^d + \hat{q}_t^e = \hat{\alpha}_{ot} + \hat{\beta}_{ot} + (\hat{\alpha}_1 + \hat{\beta}_1) p_t + \hat{\alpha}_1 g_t
\]

Equation (II-23), referred to as base case aggregate demand, is illustrated in Figure II-11. The graphical characterisation of equation (II-23), the function’s negative slope and positive vertical intercept in particular, correspond with the discussion provided in sections 2.3.2.1.3 and 2.3.2.1.4 as well as the econometric results reported in section 2.6.1.

As noted above in the description of base case export demand, at prices in excess of \((- \frac{\beta_{ot}}{\beta_1}\) ) export demand is zero. With respect to Figure II-11, this feature corresponds to the net-of-GA base case aggregate demand curve being the dash-dot line at prices in
This feature is not represented in the mathematical representation of base case aggregate demand. This would be problematic if the wholesale market clearing price plus the GA rate in any given month $t$ was ever in excess of $(-\hat{\beta}_{0t}/\hat{\beta}_1)$. This turns out not to have been the case. The reason is that the fitted values of (gross)
exports would be negative at such prices, thereby violating the non-negativity assumption.\footnote{If the wholesale market clearing price was ever in excess of \((-\hat{\beta}_{ct}/\hat{\beta}_i)\) in a given month, the simulation procedure would have to explicitly recognise this outcome and set (gross) exports to zero. As noted in the main text, this turns out not to be necessary.}

Market equilibrium is characterised by aggregate supply, equation (II-16), equaling aggregate demand, equation (II-23). In section 2.3.2.4, the wholesale market equilibrium was characterised by

\[ q^d_t + q^e_t = (1 - \text{losses}) \times (q^s_t + q^l_t) \tag{II-9} \]

This equilibrium is illustrated in Figure II-12, which is a combination of Figures II-8 and II-11. The illustrated equilibrium ignores the issue of line losses—which generally results in observed aggregate supply being less than observed aggregate demand—as specified in equation (II-9).

The base case wholesale market clearing price is determined by the intersection—labelled point E—of base case aggregate supply with base case aggregate demand and is denoted \(p^*_t\) in Figure II-12. The illustrated equilibrium makes use of five of the six equations in the system: Ontario-based supply, imports, Ontario-based demand, exports, and the quantity equilibrium condition. This equilibrium depends, however, on the magnitude of \(g^*_t\). Notwithstanding this, the GA rate is an endogenously determined variable as a result of the sixth equation of the system that is not illustrated in Figure II-12: the regulator’s budget constraint, equations (II-5), (II-7), and (II-8).

It is useful to consider the role of the regulator’s budget constraint in the determination of the wholesale market equilibrium. Suppose the GA rate in a given month is 0, \(i.e.,\), \(g^*_t = 0\). As per equation (II-5), the regulator will raise no revenue. In this case, the gross-of-GA and net-of-GA demand curves are coincident. The wholesale market
would clear as illustrated in this section, thereby determining the wholesale market clearing price as well as the four endogenously determined quantities. This outcome is
an equilibrium if and only if the regulator’s budget is balanced, that is, if equation (II-8) holds at equality. In this case, since the regulator generates no income, it cannot have an equilibrium if and only if the regulator’s budget is balanced, that is, if equation (II-8) holds at equality. In this case, since the regulator generates no income, it cannot have net expenses, as per equation (II-7), that differ from 0.\textsuperscript{48} If the regulator’s budget constraint does not hold at equality, then it cannot be the case that $g_t^* = 0$.

The manner in which the regulator’s budget constraint fails to hold is instructive with respect to whether the equilibrium GA rate is positive (a charge to Ontario-based consumers) or negative (a rebate to Ontario-based consumers). In particular, if the regulator’s budget is in deficit when $g_t^* = 0$, then a (positive) GA rate must be charged to consumers in order to raise the required revenues and bring the budget into balance. Conversely, if the regulator’s budget is in surplus when $g_t^* = 0$, then a (negative) GA rate must be rebated to consumers in order to dispense the negative expenses collected by the regulator under its supply procurement contracts and bring the budget into balance. Any GA rate that differs from zero will result in the gross-of-GA and net-of-GA demand curves necessarily being non-coincident. This more general situation is illustrated in Figure II-12. The lowest GA rate that clears the wholesale market and balances the regulator’s budget constitutes the equilibrium GA rate.\textsuperscript{49}

As stated above, an analytical solution to this model is provided for in Appendix II-C.

\textsuperscript{48} This does not mean that the regulator cannot provide out-of-market payments to any particular generator. Rather, it requires that the sum of all out-of-market payments—which may be negative—be zero. See Appendix II-B for further discussion.

\textsuperscript{49} The regulator’s budget constraint is quadratic in the GA rate. This can be seen from equation (II-5), where the regulator’s revenue is written as the product of the GA rate and the quantity of Ontario-based demand, which is itself a function of the GA rate as per equation (II-3). As a result, there are potentially two unique, real solutions to the mathematical procedure that solves for the GA. The lowest GA rate is chosen so as to minimise the impact of the regulator on the market equilibrium.
2.6.2. Base case results

The fully-parameterised system—using the results reported in Table II-3—of six equations is solved for the base case values of each of the six endogenous variables as described above. This section reports the results of this simulation, along with a restatement of certain statistics regarding the observed data.

Table II-5 reports the mean and standard deviations of the observed and base case endogenous variables for all 110 months of the study period and the last 24 months only. Figure II-13 plots the observed and base case time series for the wholesale market clearing price over all 110 months. Figures II-14, II-15, and II-16 report comparable data in relation to the wholesale market clearing price, GA, all-in price, and four endogenous quantity variables, respectively.

Table II-5: Mean and standard deviation of observed and base case endogenous variables

<table>
<thead>
<tr>
<th>Variable</th>
<th>Case</th>
<th>All Months</th>
<th></th>
<th>Last 24 Months</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>Mean</td>
<td>Std. Dev.</td>
<td>Mean</td>
<td>Std. Dev.</td>
</tr>
<tr>
<td>( q_t^s )</td>
<td>Observed</td>
<td>17,483.2</td>
<td>1,264.9</td>
<td>17,161.4</td>
<td>1,282.7</td>
</tr>
<tr>
<td></td>
<td>Base Case</td>
<td>17,570.2</td>
<td>1,129.6</td>
<td>17,583.2</td>
<td>1,182.9</td>
</tr>
<tr>
<td>( q_t^i )</td>
<td>Observed</td>
<td>935.8</td>
<td>416.1</td>
<td>624.8</td>
<td>226.8</td>
</tr>
<tr>
<td></td>
<td>Base Case</td>
<td>949.0</td>
<td>306.3</td>
<td>655.8</td>
<td>195.9</td>
</tr>
<tr>
<td>( q_t^d )</td>
<td>Observed</td>
<td>16,611.5</td>
<td>1,242.8</td>
<td>15,689.5</td>
<td>1,110.6</td>
</tr>
<tr>
<td></td>
<td>Base Case</td>
<td>16,685.5</td>
<td>1,168.4</td>
<td>16,263.8</td>
<td>1,303.0</td>
</tr>
<tr>
<td>( q_t^e )</td>
<td>Observed</td>
<td>1,381.3</td>
<td>682.2</td>
<td>1,693.9</td>
<td>422.7</td>
</tr>
<tr>
<td></td>
<td>Base Case</td>
<td>1,370.7</td>
<td>459.6</td>
<td>1,519.2</td>
<td>217.1</td>
</tr>
<tr>
<td>( p_t )</td>
<td>Observed</td>
<td>49.01</td>
<td>15.32</td>
<td>33.32</td>
<td>7.40</td>
</tr>
<tr>
<td></td>
<td>Base Case</td>
<td>49.83</td>
<td>11.91</td>
<td>37.46</td>
<td>11.05</td>
</tr>
<tr>
<td>( g_t )</td>
<td>Observed</td>
<td>9.42</td>
<td>15.68</td>
<td>33.35</td>
<td>9.65</td>
</tr>
<tr>
<td></td>
<td>Base Case</td>
<td>7.71</td>
<td>12.77</td>
<td>24.85</td>
<td>11.38</td>
</tr>
<tr>
<td>( p_t + g_t )</td>
<td>Observed</td>
<td>58.44</td>
<td>9.49</td>
<td>66.67</td>
<td>4.21</td>
</tr>
<tr>
<td></td>
<td>Base Case</td>
<td>57.54</td>
<td>5.09</td>
<td>62.31</td>
<td>1.87</td>
</tr>
</tbody>
</table>
Figure II-13: Observed and base case wholesale market price

Figure II-14: Observed and base case global adjustment
The purpose of these data is to provide a descriptive-only sense of the performance of the system of equations. Formally, the fit of the system of equations can be assessed in relation to the quality of the instruments employed in estimation. As discussed in section 5, the instruments are of sufficiently high quality to proceed with estimation and inference.

Inspection of the data and figures presented above suggests that the fitted base case series approximate the observed data relatively well. Given that the fitted base case is definitionally endogenous with respect to the model, calculation of common goodness-of-fit measures generates spurious results.
3. Impact of renewable energy generation

3.1. Introduction

The first counterfactual policy under consideration relates to the impact of renewable energy procurement—taken here to mean wind- and solar-fuelled generation—on the electricity market. For greater clarity, even though water-fuelled generation is renewable in nature it is not included in the definition of renewable energy that is relevant in this analysis.

The issue of negative externalities associated with carbon emissions—including from electricity generators—has been faced by many political jurisdictions throughout the
world. The purpose of this section is to estimate the cost of Ontario’s renewable energy policy in terms of its effect on carbon emissions. With this knowledge, the cost of carbon dioxide (CO$_2$) abatement in Ontario’s electricity market can be compared to CO$_2$: abatement cost data observed in other markets as a result of alternative strategies. Such a comparison allows for conclusions to be drawn regarding the cost effectiveness of Ontario’s entry policy.

While the regulator’s generation procurement policy extends, as described in section 2, beyond renewable energy generation, the counterfactual policy under consideration in this paper focuses exclusively upon them. Under the counterfactual policy described thus far, the amount of generating capacity based in Ontario would be lower than under the base case. Given the intermittent nature of wind- and solar-fuelled generators, it is clear that a reduction of 1 MW of renewable generation capacity results in a reduction of less than 1 MWh of output in a typical hour. A reasonable and conservative regarding the reduction of output is 0.328 MWh in a typical hour, that is, that the total energy contribution of renewable energy generators averages 32.8% of capacity. It is assumed that the absence of renewable energy generation capacity is off-set by additional natural gas-fuelled generation at that rate.

Section 3 proceeds as follows. Section 3.2 discusses the motivation for and importance of considering this issue. The theoretical impact of the counterfactual policy is described in detail in section 3.3. Using this as a basis of analysis, section 3.4 reports

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50 The Independent Electricity System Operator (IESO) makes planning assumptions in its periodic, medium-term (18 months) assessments of the reliability and operability of Ontario’s electricity system. The methodology underlying these assessments assumes that monthly average wind capacity contributions range from 13.4% to 32.8%. These data are estimated from (simulated) historic wind output data. The total energy contribution from wind energy is found to average 29%. The maximum of the monthly average wind capacity contributions—32.8%, associated with January, February, and December—is used in the analysis reported in this section. See IESO (November 2011a) and IESO (November 2011b) for additional details.
counterfactual results, which are then described—in their own right and in relation to
the base case constructed in section 2—in section 3.5. Section 3.6 concludes.

### 3.2. Importance of issue and motivation of analytical approach

This section discusses the importance of studying the impact of renewable energy
generation on the market by describing the magnitude of entry and its cost. A
standardised measure of the cost of CO₂-emission abatement is then described. The
general analytical approach to estimating this value is then described.

#### 3.2.1. Importance of issue

Section 2 provided background on the development of the electricity market in Ontario.
As discussed there, one important development related to the creation of the regulator’s
programme of generation procurement. Initially, this programme focused on inducing
entry of natural gas-fuelled and, to a much lesser extent, renewable energy electricity
generators so as the implement the government’s goal of withdrawing coal-fuelled
generators from the market.\(^{51}\) Effectively, it was a CO₂-emission abatement policy.

At the end of 2005, action to achieve the initial goal of the programme was underway.\(^{52}\)
While many of the generators under contract at that time would not enter the market
for several years due to planning and building lead-times, the focus of the regulator’s

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\(^{51}\) As described in section 2, the Ontario Power Authority (OPA), referred to herein as the regulator, was
created by the *Electricity Restructuring Act, 2004*. One of the OPA’s principle activities was to develop a
long-term electricity system plan that would result in the phase-out of coal-fuelled generation in Ontario.
See section 34 of the *Electricity Restructuring Act, 2004*, which became section 25.30 of the *Electricity Act,
1998*. This legislative undertaking was in accordance with the 2003 general election platform of the
Liberal Party of Ontario, the party that formed the provincial government following that election. See

\(^{52}\) See the first annual report of the Ontario Power Authority (OPA, March 2006), which summarises the
contracts that had been created up to the end of 2005. Lakeview Generating Station, a coal-fuelled
generating station, near Toronto, was withdrawn from service on 30 April 2005. See the Market
Surveillance Panel report (MSP, June 2005) related to the six-month period ending April 2005 for
additional information regarding developments in the electricity market at that time.
programme shifted away from natural gas-fuelled generation towards renewable energy generation. Especially significant was the implementation of standardised contracts for prospective renewable energy generators in place of request for proposal-type auctions. Two such programmes have existed: the Renewable Energy Standard Offer Program (RESOP)\textsuperscript{53} and subsequently the Feed-in Tariff Program (FIT).\textsuperscript{54}

The renewable energy generation programme merits special consideration because it has a significant impact on the electricity market. Figure III-1 illustrates Ontario’s installed capacity of renewable energy generation. This capacity was 0 MW at the beginning of 2006 but had risen to approximately 1,915 MW by June 2011. In comparison, in mid-2011 there was approximately 35,000 MW of installed electricity generation capacity of all fuel types located in Ontario.\textsuperscript{55} Thus, over the first five-year period in which the regulator’s procurement policy was in place, renewable energy generation rose from 0% to approximately 6% of capacity. Figure III-2 illustrates the total production of electricity from renewable energy generators. This has risen from an hourly average of 0 MWh per hour at the beginning of 2006 to as high as 680 MWh per hour in early 2011, when it constituted approximately 3.7% of Ontario-based supply.

While the proportions of capacity and production related to renewable energy generation are small, their impact on the wholesale market is magnified by the level of the contract prices they receive. Figure III-3 illustrates the production-weighted average of contract prices received by renewable energy generators from March 2006

\textsuperscript{53} The RESOP was established by the direction of a Ministerial Directive (Ministry of Energy, 2006) issued on 21 March 2006 by Ontario’s Minister of Energy.
\textsuperscript{54} The FIT programme was established by the direction of a Ministerial Directive (Ministry of Energy and Infrastructure, 2009) issued on 24 September 2009 by Ontario’s Minister of Energy and Infrastructure.
\textsuperscript{55} There were 34,960 MW of generating capacity connected to the IESO-controlled grid in August 2011 (Independent Electricity System Operator, November 2011a). In addition, there were several hundred megawatts of generating capacity embedded within the distribution system, including approximately 235 MW of wind-fuelled capacity (Ontario Power Authority, August 2011).
Figure III-1: Capacity of renewable energy generators, by fuel type

Figure III-2: Output of renewable energy generators, all fuel types
onward. This series begins at a level of $135 per MWh, corresponding to the contract price of wind-fuelled renewable energy generation discussed in section 2, and stays there for many months until solar-fuelled renewable energy generation began to enter the market (as illustrated in Figure III-1). When this began to occur, the average contract price rose above $135 per MWh, reflecting the $420 per MWh contract price offered to solar-fuelled generation.

Figure III-4 illustrates the contents of Figures II-3 and III-3 jointly: the wholesale market clearing price, the global adjustment rate, the all-in price, and the average renewable energy contract price. It is immediately evident that renewable energy contract prices are well in excess of the wholesale market clearing price. As described in the construction of the regulator’s budget constraint in section 2, contractually guaranteed revenue that is not obtained from the wholesale market is provided by the regulator in
the form of out-of-market top-up payments. Figure III-4 makes clear that these top-up payments, funded through the GAM, constitute a majority of the revenue received by the typical renewable energy generator. It is in this way that the impact of renewable energy production on the market is magnified well beyond the level suggested by the fraction of total capacity and output associated with renewable energy.

Presentation of these data is not intended to act as an analysis of renewable energy in its own right, but rather to illustrate the importance of policy-induced entry on the market and to motivate further analysis.

3.2.2. Motivation of analytical approach

The most useful measure of the (average) social cost of CO₂-emission abatement as a result of the programme is the number of dollars spent per tonne of CO₂ abated, *i.e.*,
$/tonne of CO\textsubscript{2}. This is because it is a normalisation that facilitates comparison to alternative approaches taken in other jurisdictions and markets. This calculation requires two inputs: the total (social) cost of the programme in dollars and the number of tonnes of CO\textsubscript{2} emissions abated as a result of the expenditure.

The model developed and reported in section 2 can be used to find each of these inputs. Calculation of each value is described in turn.

The cost of the programme in social terms can be estimated by calculating the amount by which total surplus differs under the counterfactual policy of no renewable energy generation in comparison to the base case. Surplus is obtained by each of the four types of economic agents considered: consumers based in Ontario (Ontario-based demand), producers based in Ontario (Ontario-based supply), and inter-jurisdictional traders (imports and exports). The impact of the counterfactual on each of these groups of agents must be considered.

Ontario-based consumers pay the all-in price, which is the sum of the wholesale market clearing price and the GA rate. The impact of the counterfactual policy need not have symmetric effects on the components of this price. That is, one component could increase while the other decreases. Since Ontario-based consumers pay both, it is the net impact of the counterfactual policy that is relevant to consumers. Any change of the all-in price, therefore, impacts consumers’ surplus. The effects of the individual components of the all-in price are not considered.

Traders who export electricity buy it in the wholesale market and pay the wholesale market clearing price.\textsuperscript{56} These consumers do not pay the GA rate on their purchases. As a result, a change of the wholesale market clearing price impacts the surplus they

\textsuperscript{56} The impact of transmission system congestion on electricity pricing is ignored in this paper. See Olmstead (2012) for an assessment of Ontario’s market for financial transmission rights (FTR).
obtain from their activities while they are indifferent to the (direct) effect a changing GA rate.

Similarly, traders who import electricity sell it in the wholesale market and receive the wholesale market clearing price. As a result, a change of the wholesale market clearing price impacts the surplus they obtain from their activities.

The last group of relevant economic agents (aside from the government) is Ontario-based producers. As described in detail in section 2 and Appendices II-B and II-C, the incentives faced by these producers are not uniform across all firms. Some producers are significantly exposed to changes of the state of the wholesale market, the wholesale market clearing price in particular. The hydroelectric generators owned by Ontario Power Generation (OPG) are an example of a class of producers of this type. A change of the wholesale market clearing price affects the surplus obtained by such producers.

Other producers are indifferent to the state of the wholesale market. Generators that operate under fixed-price contacts, such as non-utility generators (NUGs), are an example of a class of producers of this type. These firms receive the same, contractually-specified price per unit of output irrespective of the wholesale market clearing price through the payment of out-of-market top-ups by the regulator. While the wholesale market clearing price may change under the counterfactual policy, exactly off-setting changes in the out-of-market top-up payments nullify the impact on such firms. Thus, the surplus obtained by such firms does not change as a result of the counterfactual policy.

The exception among generators that operate under fixed-price contracts are those that would not have entered in the first instance under the counterfactual policy. Any

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57 See the previous footnote regarding the impact of transmission system congestion on the electricity market.
surplus that would have been obtained by these firms associated with entering the market is lost under the counterfactual policy. Renewable energy generators—such as wind- and solar-fuelled generators—fall in this category in relation to the particular counterfactual policy under consideration. If, however, the contract prices offered by the regulator’s programme to induce entry by renewable energy generators are set so as to do so at lowest cost, then the entering firms will earn approximately zero producers’ surplus. In this case, there would be no loss of surplus associated with such firms not entering the market under the counterfactual policy.

The change of total surplus associated with the counterfactual policy of an absence of the regulator’s programme of policy-induced entry of renewable energy generation is the sum of the individual effects outlined above. This can be thought of as the social cost of the obtaining the environmental effects of the programme for all relevant market participants collectively.58

The final component of the wholesale market equilibrium is the budget constraint of the regulator itself, equation (II-8). Before considering this particular budget constraint, consider the impact on total surplus of a revenue-seeking government levying taxes on sales in general. In the classic analysis of the welfare effects of a distortionary tax, the imposition of a tax on a commodity results in a wedge emerging between the price paid by consumers and the price received by producers. The size of the wedge is the tax rate. In a typical case, there is a transfer of surplus from both consumers and producers to the government. This revenue is not considered to constitute a total loss of social welfare because it can be used to finance either lump-sum transfers to consumers or some other socially valuable endeavour. See Mas-Colell, Whinston, and Green (1995, p. 331) for further discussion. In the context of Ontario’s electricity market, the revenue

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58 Total surplus is presumably greater under the counterfactual policy than under the base case. This presumption is based in the expectation that policy-induced entry into a market is not free.
raised by the regulator is used to fund programmes whose effects are felt within the market itself. Of particular importance is the use of these revenues to shift the supply curve by, for instance, running programme of policy-induced entrance of renewable energy generators. In any event, most of the revenue collected by the regulator is not used to finance either lump-sum transfers to consumers or some other socially valuable endeavour.\textsuperscript{59} This is not to say that the regulator’s revenue itself constitutes a loss of surplus. Since the regulator spends each dollar it raises within the electricity market, this revenue again appears in the surplus calculations of the economic agents discussed above.

In the context of Ontario’s electricity market, since both the GA rate and the level of Ontario-based demand may change under the counterfactual policy equilibrium, the amount of revenue collected by the regulator may also change. Given that the regulator’s budget must balance, the amount of funds distributed by the regulator must change symmetrically. Thus, the change in the regulator’s revenue will feed through the regulator and manifest itself in the outcomes of the economic agents discussed above.

To recapitulate, consider the counterfactual policy from the opposite perspective, that is, by thinking about the base case as having no renewable energy generators and the counterfactual policy as their contracted entry. Assume again that the entering firms earn zero economic profit, that is, the revenue they receive is exactly equal to the cost—including fixed cost—they incur. The cost of covering the fixed cost associated with entry is entirely a dead-weight loss from the perspective of the market. The loss, which manifests itself in the market through the GA rate, is incurred against consumers

\textsuperscript{59} Some of the regulator’s expenditures do not directly impact the position of the supply curve. For instance, conservation spending. These expenditures are not considered to constitute a loss of surplus. Irrespective of this assumption, there can be no change in surplus associated with them that must be considered when comparing a counterfactual policy to the base case.
through a higher all-in price and non-contracted producers through a lower wholesale market clearing price. Not considering the avoidable nature of fixed cost under the counterfactual policy amounts to assuming that renewable energy capacity is free.

The number of tonnes of CO\textsubscript{2} emissions abated by the programme can be determined by consideration of the difference in the composition of Ontario-based supply between the base case and the counterfactual policy. In particular, under the counterfactual policy there is no output from renewable energy generators. The difference in total output must, therefore, come from producers that emit CO\textsubscript{2} as they produce electricity. This incremental output is assumed to come from natural gas-fuelled generators.\textsuperscript{60}

With these results, the average cost of abating one tonne of CO\textsubscript{2} emissions under the programme of policy-induced entrance of renewable energy generators can then be estimated. The details of the necessary calculations are reported in the next section.

### 3.3. Analytical approach and anticipated effects

As described in the previous section, there are two aspects to the calculation of the cost of CO\textsubscript{2} emission abatement under the regulator’s programme of generation procurement. First, there is the change in total surplus as a result of the programme. Second, there is the change in CO\textsubscript{2} emissions as a result of the programme. The previous section also outlined how these calculations would be made in general terms. A detailed description is provided here.

Section 3.3.1 describes how the counterfactual equilibrium is modelled in the context of the model introduced in section 2. Sections 3.3.2 and 3.3.3 describe, respectively, how

\textsuperscript{60} It is assumed that baseload generators—hydro and nuclear in particular—as well as peaking hydro generators are fully utilised under both the base case and the counterfactual policy. Since coal-fuelled generators are being phased-out of the market, the incremental supply must come from the only other source: natural gas-fuelled generators.
the change in total surplus and the change in CO₂ emissions between the counterfactual policy and the base case are measured. The cost of CO₂ emission abatement described in section 3.3.4.

3.3.1. Counterfactual equilibrium

In order to make these calculations, the details of the appropriate counterfactual policy must be specified. The presence of renewable energy generation impacts the market equilibrium through three mechanisms: it impacts Ontario-based supply, it contributes costs (potentially negative) that must be recovered by the GA, and it displaces other types of generation capacity.

To determine the impact of the counterfactual policy, the three mechanisms described above must be accounted for. First, the amount of baseload supply must be amended to exclude the contributions made to it by renewable energy. Second, the equation that describes the regulator’s expenses must be amended to exclude out-of-market top-up payments to renewable energy generators. Third, that must be further amended to include costs associated with payments to the non-renewable energy generation capacity that replaces renewable generation.

In terms of the market model introduced in section 2, the first mechanism impacts the baseload time series in

\[ q_t^s = \gamma_0 + \gamma_1 p_t + \gamma_2 fuel_t + \gamma_3 baseload_t + \varepsilon_{1t} \]  \hspace{1cm} (II-1)

which would be lower by the magnitude of observed energy output from wind- and solar-fuelled generators located in Ontario. Crucially, the econometrically-derived coefficient estimates are assumed to be unchanged. In other words, the Ontario-based supply curve shifts to the left under the counterfactual.
The second and third mechanisms impact aspects of the regulator’s expenses and, therefore, appear in the regulator’s budget constraint. In particular, out-of-market top-up payments required to induce renewable energy entry in the first instance are components of the regulator’s expenses and, therefore, appear in the regulator’s budget constraint. A no-renewable energy counterfactual policy would be associated with the absence of these payments (costs). In particular,

\[ \text{Exp}_t = q_t^{\text{wind}} \times (135 - P_t) + q_t^{\text{solar}} \times 0.19 \times (420 - P_t) \]

\[ + 1577 \times (75 - P_t) + q_t^{\text{nuclear}} \times (55 - P_t) + 1900 \times (33 - P_t) \]

\[ + \text{nat}_t \times \text{gas} \times \text{capacity}_t + \text{contingency}_t + \text{conservation}_t \]  \hspace{1cm} (II-7)

would reflect both the absence of wind- and solar-fuelled output, \( q_t^{\text{wind}} = q_t^{\text{solar}} = 0 \), and a scaling-up of natural gas capacity costs in proportion to the amount of renewable energy generation capacity eliminated as described in section 3.2.

Holding the GA rate constant, a reduction of supply associated with the absence of output from renewable energy generators would result in an increase of the wholesale market clearing price, along with increased imports, and decreased Ontario-based demand and exports. Due to the higher wholesale market clearing price, the generators that remain in the market would earn greater revenue than otherwise. A subset of these generators operates under contractual arrangements with the regulator that entitles them to receive the out-of-market top-up payments described in section 2 and Appendix II-B. These payments are, in aggregate, reduced as a result of the higher wholesale market clearing price. The result is that the regulator’s budget has a surplus, thereby placing downward pressure on the GA rate initially held constant.

Likewise, a reduction of supply associated with the absence of output from renewable energy generators would eliminate the out-of-market top-up payments that were
necessary to induce entry of such generation in the first instance.\textsuperscript{61} As a result, the expenses included in equation (II-7) would be less than otherwise, thereby placing additional downward pressure on the GA rate.

Taken together, a reduction of supply associated with the absence of output from renewable energy generators would raise the wholesale market clearing price and reduce the GA rate. The net impact on the all-in price depends principally on the average contract price paid for renewable energy relative to the wholesale market clearing price. Since renewable energy generation is procured at average contract prices several times the average wholesale market clearing price, the net impact on the all-in price is expected to be negative.\textsuperscript{62}

Offsetting this effect is the additional cost borne by the regulator of the natural gas-fuelled capacity that replaces the renewable energy capacity. As described in section 3.2, the amount of incremental natural gas-fuelled capacity is defined to be a constant proportion (33\%) of the renewably-fuelled capacity eliminated under the counterfactual policy. Relative to the former effects, the latter effect is expected to be small.\textsuperscript{63}

A lower all-in price implies that Ontario-based demand will be higher. A higher wholesale market clearing price implies that exports (imports) will be lower (higher).

The impact of the regulator’s policy of generation procurement as it relates to

\textsuperscript{61} The average prices to which renewable energy generation is topped-up are well above average market clearing prices. This is illustrated in Figure III-4. It is because of this relationship that such generation will only enter the market under special contractual terms.

\textsuperscript{62} See previous footnote. In Appendix II-C it is shown that if the (capacity) weighted-average of contract prices offered by the regulator exceeds the wholesale market clearing price that would prevail in the absence of regulatory intervention regarding supply, then the GA rate must be positive. Given that contract prices offered to renewable energy generators exceed the levels offered to other types of generation, entry of renewable energy generation capacity raises this weighted-average and, by extension, the GA rate. Thus, under the counterfactual policy both are lower than otherwise.

\textsuperscript{63} To begin with, natural gas-fuelled capacity is less expensive than renewable energy capacity. This relationship is reflected by the relatively high contract prices offered to renewable energy generators.
renewable energy can be looked at from the opposite perspective compared to that above, that is, the impact on the wholesale market equilibrium of the entry of renewable energy generation. Holding the GA rate constant, such entry increases supply at all price levels, thereby lowering the wholesale market clearing price. The lower wholesale market clearing price means those contractual payments to non-renewable generators will increase, creating a budget deficit for the regulator, thereby placing upward pressure on the GA rate. Given the relatively high costs associated with inducing the entry of renewable generation into the market, the resulting equilibrium is expected to be one where the wholesale market price is lower, but the GA rate and all-in price are both higher.

3.3.2. Change of total surplus

Once the counterfactual policy equilibrium has been simulated, the associated change in total surplus can be calculated. To facilitate this discussion, use is made of modified versions of Figures II-6, II-7, II-9, and II-10, the Figures that illustrate base case Ontario-based supply, imports, Ontario-based demand, and exports.

A particular notation convention is adopted. Base case values are denoted with superscript asterisks (*). Counterfactual policy values are denoted with superscript primes ('). Additional notational conventions are defined locally where necessary.

First, consider the impact of the counterfactual policy on the surplus obtained by Ontario-based supply. As described above, the impact of changing wholesale market conditions on producers varies according to the contractual arrangements that exist between individual producers and the regulator. Some producers are exposed to the wholesale market clearing price and others are not. Those that are not exposed lack exposure because they receive compensation from the regulator that neutralises the impact on them of changing wholesale market conditions. As a result, such producers
do not experience a change of surplus under the counterfactual policy relative to the base case. The exception is those renewable energy generators that are eliminated from the market under the counterfactual policy. If, however, these generators were induced to enter the market with contracts that ensured approximately zero economic profits, then these generators would not lose surplus under the counterfactual policy either. Those non-contracted generators that are exposed to the wholesale market clearing price gain surplus if the price rises and lose surplus if the price falls. The details of these contractual arrangements are described in greater detail in section 3.2, as well as in section 2.

Conceptually, a supply curve that corresponds to the subset of non-contracted Ontario-based generators that are exposed to the wholesale market clearing price can be constructed. Since such a curve represents a fraction of Ontario-based supply, it must relate a smaller quantity to each price than either the base case or counterfactual Ontario-based supply. For notational convenience, this sub-supply curve is denoted with superscript noughts ($^0$).

Figure III-5 illustrates base case and counterfactual policy Ontario-based supply. The sub-supply curve related to non-contracted generation is also illustrated. The base case equilibrium wholesale market clearing price is $p^*_t$, while the counterfactual policy equilibrium wholesale market clearing price is $p'_t$. As argued above, and with foreknowledge of the results to be reported in the next section, the figure assumes that $p^*_t < p'_t$.

As stated above, this price change only impacts the surplus obtained by non-contracted generators. The amount of supply provided by non-contracted supply can be read off the sub-supply curve. In particular, base case non-contracted supply is $S^0(p^*_t)$ while counterfactual non-contracted supply is $S^0(p'_t)$. The result that $S^0(p^*_t) < S^0(p'_t)$ follows
from \( p^*_t < p^*_t \) and the presumption that non-contracted supply is increasing in the wholesale market clearing price. The change in surplus obtained by Ontario-based supply is the shaded area in Figure III-5 and can be represented mathematically as

\[
\Delta PS_{ontario}^t = \int_{p^*_t}^{p^*_t} S^o(x)dx
\]

\[
= \frac{1}{2} [S^o(p^*_t) + S^o(p^*_t)] * [p^*_t - p^*_t]
\]  

(III-1)

The second equality in equation (III-1) follows from the linear specification of the various supply curves resulting in the shaded area in Figure III-5 being a trapezoid.

*Figure III-5: Changing surplus of Ontario-based supply*
An increase of the wholesale market clearing price under the counterfactual policy will increase the surplus obtained by non-contracted Ontario-based generators (and by extension Ontario-based generators collectively). That is $\Delta P_{t, \text{Ontario supply}} > 0$. This change of surplus obtained by Ontario-based supply constitutes the first part of the change of total surplus under the counterfactual policy.

Figure III-6: Changing surplus of import supply

The impact of the counterfactual policy on the surplus obtained by other economic agents in the market is more straightforward to measure because the counterfactual policy does not impact the fundamental characteristics of these agents, just the price they pay for their consumption or are paid for their supply.

Figure III-6 illustrates the change of surplus obtained by importers of electricity to Ontario under the counterfactual policy. Surplus changes because the price paid to imports, the wholesale market clearing price, changes. The change in surplus is the
shaded area in Figure III-6 and can be represented mathematically as

\[ \Delta P_{it}^{imports} = \int_{p_i^t}^{p_i^{t'}} \hat{q}_i(x) dx = \frac{1}{2} [q_i^{t'} + q_i^{t}] \ast [p_i^{t'} - p_i^t] \]  

(III-2)

where \( \hat{q}_i(x) \) denotes the level of exports at price \( x \). This area is also a trapezoid due to the linear specification of the import supply curve. An increase of the wholesale market clearing price under the counterfactual policy will increase the surplus obtained by importers. That is \( \Delta P_{it}^{imports} > 0 \). This change of surplus obtained by importers constitutes the second part of the change of total surplus under the counterfactual policy.

Figure III-7 illustrates the change of surplus obtained by Ontario-based consumers of electricity under the counterfactual policy. Surplus changes because the price paid by consumers, the all-in price (the sum of the wholesale market clearing price and the GA rate), changes. The change in surplus is the shaded area in Figure III-7 and can be represented mathematically as

\[ \Delta CS_{it}^{Ontario Demand} = \int_{p_i^t + g_i^t}^{p_i^{t} + g_i^{t'}} \hat{q}_i^d(x) dx = \frac{1}{2} [q_i^{d,t'} + q_i^{d,t}] \ast [(p_i^t + g_i^t) - (p_i^{t'} + g_i^{t'})] \]  

(III-3)

where \( \hat{q}_i^d(x) \) denotes the level of Ontario-based consumption at price \( x \). This area is also a trapezoid due to the linear specification of the Ontario-based demand curve. A decrease of the all-in price under the counterfactual policy will increase the surplus obtained by Ontario-based consumers. That is \( \Delta CS_{it}^{Ontario Demand} > 0 \). This change of surplus obtained by Ontario-based consumers constitutes the third part of the change of total surplus under the counterfactual policy.

Figure III-8 illustrates the change of surplus obtained by exporters of electricity from Ontario under the counterfactual policy. Surplus changes because the price paid for
exports, the wholesale market clearing price, changes. The change in surplus is the shaded area in Figure III-8 and can be represented mathematically as

\[
\Delta CS^\text{Exports}_t = -\int_{p_t^*}^{p_t'} q_t^*(x)dx
\]
\[
= -\frac{1}{2}[q_t^{e'} + q_t^{e*}] [p_t' - p_t^*]
\]  

(III-4)
where $q_t^e(x)$ denotes the level of exports at price $x$. This area is also a trapezoid due to the linear specification of the export demand curve. An increase of the wholesale market clearing price under the counterfactual policy will decrease the surplus obtained by exporters. This is the source of the negative sign in equation (III-4). That is $\Delta CS_t^{Exports} < 0$. This change of surplus obtained by exporters constitutes the fourth part of the change of total surplus under the counterfactual policy.

The change of total surplus under the counterfactual policy is simply the sum of the changes in surplus obtained by each of the four groups of economic agents considered. That is

$$\Delta TS_t = \Delta PS_t^{Ontario\ Supply} + \Delta PS_t^{Imports} + \Delta CS_t^{Ontario\ Demand} + \Delta CS_t^{Exports} \quad (III-5)$$

Since the four terms of equation (III-5) are not expected to be of the same sign, the sign of $\Delta TS_t$ itself is ambiguous. The change in total surplus is measured in dollars.
The expected results illustrated above depend on the wholesale market clearing price being higher and the all-in price being lower under the counterfactual policy than under the base case, that is: \( p_i' > p_i^* \) and \( p_i' + g_i' < p_i^* + g_i^* \). If this were to turn out not to be the case, equations (III-1), (III-2), (III-3), and (III-4) would continue to represent changes of surplus obtained by the various groups of economic agents, but the signs of the changes would differ. Equation (III-5) would continue to represent the change of total surplus due to the counterfactual policy.

### 3.3.3. Change of CO₂ emissions

Generators that are fuelled by fossil fuels emit CO₂ as they produce electricity. Other generators, including those wind- and solar-fuelled, do not. Once the counterfactual policy equilibrium has been simulated, the associated change in CO₂ emissions can be calculated. This calculation depends on how the composition of supply differs under the counterfactual policy from the base case. Attention here is restricted to CO₂ emissions from Ontario-based supply alone.

The amount of Ontario-based supply under the base case and the counterfactual policy is \( q_t^{s*} \) and \( q_t^{s'} \), respectively. The difference between the two values is the change of Ontario-based supply under the counterfactual policy, that is

\[
\Delta q_t^S = q_t^{s'} - q_t^{s*}
\]  

(III-6)

This can be seen in Figure III-5.

Assume that the marginal Ontario-based supplier is a natural gas-fuelled generator. Then the change in Ontario-based supply that is produced from CO₂-emitting generators can be decomposed into two parts: the change in the level of supply and the change in the composition of supply. That is
\[ \Delta q_t^{s,\text{Carbon Emitting Supply}} = \Delta q_t^s + \left( q_t^{\text{wind}} + q_t^{\text{solar}} \right) \]  

(III-7)

Consider each of these effects. First, a change in the level of supply would result in a change in output of the marginal, CO₂-emitting supplier. Second, the renewable energy generation that is eliminated from the market under the counterfactual policy would be replaced by the marginal, CO₂-emitting supplier. The change is reported in average MWh per hour of electricity.

Define \( \theta \) to be the CO₂ emissions in tonnes per MWh of electricity generated by the marginal supplier, which is assumed to be natural gas-fuelled. Effectively, \( \theta \) measures the CO₂ intensivity of the marginal supplier and is reported in tonnes per MWh of electricity generation. Then the change of CO₂ emissions associated with the counterfactual policy is

\[ \Delta CO2_t = \theta \times \Delta q_t^{s,\text{Carbon Emitting Supply}} \]  

(III-8)

In other words, the change in carbon dioxide emissions under the counterfactual policy is the change in the amount of electricity generated by natural gas-fuelled producers multiplied by the CO₂-intensivity of those generators. The change is measured in tonnes of CO₂.\(^{64}\)

Detailed analysis of the technical characteristics of typical natural gas-fuelled generators allows for \( \theta \) to be estimated. Gagnon, Bélanger, and Uchiyama (2002) report that a reasonable value of \( \theta \) in a North American (or European) context is 0.443 tonnes of CO₂ per MWh of electricity.\(^{65}\)

\(^{64}\) This is because \( \theta \) is measured in tonnes of CO₂ per MWh of electricity generation and \( \Delta q_t^{s,\text{Carbon Emitting Supply}} \) is measured in MWh of electricity generated.

\(^{65}\) Equation (III-8) captures the change in CO₂ emissions associated with increased use of natural gas-fuelled generators under the counterfactual policy. This analysis ignores the stand-by generation, typically natural gas-fuelled, that is necessary under the base case to act as back-up for renewable energy.
3.3.4. Cost of CO$_2$ emission abatement

The results obtained from the analyses reported in sections 3.3.2 and 3.3.3 can be used to estimate the average cost of carbon dioxide emission abatement (COA).

In particular, the COA is the ratio of equations (III-5) and (III-8). That is

$$COA_t = \frac{\Delta TS_t}{\Delta CO2_t}$$ (III-9)

Since the change in total surplus is measured in dollars and the change in CO$_2$ emissions is measured in tonnes of CO$_2$, then COA is measured in dollars per unit of CO$_2$ abated (as a result of the regulator’s programme of renewable energy generation capacity procurement). This is a standardised measure of the cost of CO$_2$ abatement that can be used to compare Ontario’s approach with those taken in other markets and jurisdictions.

3.4. Empirical results

This section reports the empirical results associated with implementation of the analytical approach described in the previous section. Section 3.4.1 reports the counterfactual policy equilibrium under which no renewable energy generation capacity is induced by the regulator to enter the market. The results are contrasted with the base case in the related discussion. Section 3.4.2 reports the change in total surplus between the counterfactual policy and the base case, while section 3.4.3 reports the associated change in CO$_2$ emissions. Section 3.4.4 reports the estimated cost of CO$_2$ abatement due to Ontario’s programme of renewable energy capacity procurement.

generation due to its intermittent nature. Also ignored is the fact that renewable energy generation itself is not truly free of CO$_2$ emissions. For instance, Pehnt (2006) reports that the $\theta$ associated with renewable energy generation equals approximately 0.010 for wind- and solar-fuelled generators.
3.4.1. Counterfactual equilibrium

Table III.1 reports the mean and standard deviation of each of the endogenous variables in the model under both the base case and the counterfactual policy. The statistics are presented for all 110 months of the study period and the last 24 months only.

Figures III-9, III-10, and III-11 illustrate the base case and no-renewable energy counterfactual policy values for the wholesale market clearing price, the GA rate, and the all-in price, respectively.

Qualitatively, the counterfactual policy results reported in Table III.1 correspond with the theoretical expectations outlined in section 3 for both (i) all 110 months of the study period and (ii) the last 24 months of the study period.

These results, in addition to Figures III-9, III-10, and III-11, show that the impact on

<table>
<thead>
<tr>
<th>Variable</th>
<th>Case</th>
<th>All Months</th>
<th>Last 24 Months</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>Mean</td>
<td>Std. Dev.</td>
</tr>
<tr>
<td>$q_t^i$</td>
<td>Base Case</td>
<td>17,570.2</td>
<td>1,129.6</td>
</tr>
<tr>
<td></td>
<td>No Renew.</td>
<td>17,568.3</td>
<td>1,120.0</td>
</tr>
<tr>
<td>$q_t^d$</td>
<td>Base Case</td>
<td>985.0</td>
<td>306.3</td>
</tr>
<tr>
<td></td>
<td>No Renew.</td>
<td>975.9</td>
<td>288.9</td>
</tr>
<tr>
<td>$q_t^e$</td>
<td>Base Case</td>
<td>16,685.5</td>
<td>1,168.4</td>
</tr>
<tr>
<td></td>
<td>No Renew.</td>
<td>16,738.8</td>
<td>1,142.1</td>
</tr>
<tr>
<td>$q_t^f$</td>
<td>Base Case</td>
<td>1,367.7</td>
<td>459.6</td>
</tr>
<tr>
<td></td>
<td>No Renew.</td>
<td>1,341.9</td>
<td>450.1</td>
</tr>
<tr>
<td>$p_t$</td>
<td>Base Case</td>
<td>49.83</td>
<td>11.91</td>
</tr>
<tr>
<td></td>
<td>No Renew.</td>
<td>51.16</td>
<td>10.74</td>
</tr>
<tr>
<td>$g_t$</td>
<td>Base Case</td>
<td>7.71</td>
<td>12.77</td>
</tr>
<tr>
<td></td>
<td>No Renew.</td>
<td>5.75</td>
<td>10.48</td>
</tr>
<tr>
<td>$p_t + g_t$</td>
<td>Base Case</td>
<td>57.54</td>
<td>5.09</td>
</tr>
<tr>
<td></td>
<td>No Renew.</td>
<td>56.91</td>
<td>4.69</td>
</tr>
</tbody>
</table>
The market equilibrium of the regulator’s policy of generation procurement as it relates to renewable energy has been growing through time. This finding is consistent with the expectations regarding how the regulator’s policy would manifest itself, namely that the impact would gradually appear in the market as the generation procured entered service.

The results indicate that consumers located in Ontario faced higher all-in electricity prices as a result of the procurement policy. The results also indicate that non-contracted generators lost quasi-rents as a result of the procurement policy. This is a result of the policy’s negative effect on the wholesale market clearing price.

In particular, over the whole study period, the analysis concludes that in the absence of renewable energy generation the average wholesale market clearing price would be
$51.16 per MWh instead of $49.83, an increase of $1.33 per MWh (2.7%). The GA rate would be $5.75 per MWh instead of $7.71 per MWh, a reduction of $1.96 per MWh (25.4%). The Ontario all-in price would be $56.91 per MWh instead to $57.54 per MWh, a reduction of $0.63 per MWh (1.1%). With respect to quantities, Ontario-based demand would increase by 53.3 MWh per hour (0.3%), imports would increase by 26.9 MWh per hour (2.8%), exports would decrease by 28.8 MWh per hour (2.1%), and Ontario-based supply, net of the reduction due to the absence of renewable generation, would decrease by 1.9 MWh per hour (0.0%).

From the opposite perspective, implementation of the renewable energy procurement policy resulted in the all-in price paid by Ontario-based demand increasing by $0.63 per MWh (1.1%) and the wholesale market clearing price received by non-contracted Ontario-based generation decreasing by $1.33 per MWh (2.6%). Thus, the total cost on a
per MWh basis borne jointly by Ontario-based demand and non-contracted Ontario-based supply is $1.96 per MWh. This is definitionally equal to the reported increase of the GA rate. Ontario-based demand declined by 53.3 MWh per hour (0.3%), imports declined by 26.9 MWh per hour (2.8%), exports increased by 28.8 MWh per hour (2.1%), and Ontario-based supply increased by 1.9 MWh per hour (0.0%).

Over the last 24 months of the study period, the simulations report that in the absence of renewable energy generation the wholesale market clearing price would be $41.46 per MWh instead of $37.46 per MWh, an increase of $4.00 per MWh (10.7%). The GA rate would be $18.72 per MWh instead of $24.85 per MWh, a reduction of $6.13 per MWh (24.7%). The Ontario all-in price would be $60.19 per MWh instead of $62.31 per MWh, a reduction of $2.12 per MWh (3.4%). With respect to quantities, Ontario-based demand would increase by 179.9 MWh per hour (1.1%), imports would increase by 81.1
MWh per hour (12.4%), exports would decrease by 86.8 MWh per hour (5.7%), and Ontario-based supply, net of the reduction due to the absence of renewable generation, would *increase* by 14.3 MWh per hour (0.1%).

From the opposite perspective, implementation of the renewable energy procurement policy resulted in the all-in price paid by Ontario-based demand to increase by $2.12 per MWh (3.5%) and the wholesale market clearing price received by non-contracted Ontario-based generation decreasing by $4.00 per MWh (9.6%). Thus, the cost borne jointly by Ontario-based demand and non-contracted Ontario-based supply is $6.13 per MWh. This is definitionally equal to the reported increase of the GA rate.\(^{66}\)

Policy-induced entrants were not affected by the procurement policy by virtue of the contractual terms under which they entered the market. Non-contracted generators and Ontario-based consumers experienced losses as a result of, respectively, a reduction of the wholesale market clearing price and an increase of the all-in price. The results also indicate that the procurement policy incentivised incrementally greater exports. Since the average price paid for exports declined, infra-marginal exports became more profitable than they would have otherwise been. For analogous reasons, imports faced the opposite outcome. More precise measures of the impact of the procurement policy are reported in the next section where the surplus—and change thereto—obtained by each group of economic agents is considered.

Finally, while the data used in this study are observed at a monthly frequency, it is useful to recall that the wholesale market clearing price varies at a 5-minute frequency whereas the GA rate varies at a 1-month frequency.\(^{67}\) Thus, the growing importance of the GA rate in the all-in price of electricity can be interpreted as a shift away from

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\(^{66}\) It is due to rounding that $2.12 and $4.00 do not sum to $6.13.  
\(^{67}\) An hourly wholesale market clearing price, known as the hourly Ontario energy price (HOEP), is the mean of the twelve 5-minute prices observed within each hour.
incremental cost pricing towards average cost pricing, an outcome which has negative implications for the allocative efficiency of the wholesale market.

3.4.2. Change of total surplus

The change in total surplus is the sum of the changes in surplus obtained by each of the four groups of economic agents. Formulae for the change of surplus obtained by Ontario-based supply, imports, Ontario-based demand, and exports under the counterfactual policy compared to the base case are given by equations (III-1), (III-2), (III-3), and (III-4), respectively.

Table III-2 reports the mean and standard deviation of the changes in surplus obtained in an average hour by each of the four groups of economic agents under the counterfactual policy. The change of total surplus is reported as well. The statistics are presented for all 110 months of the study period and the last 24 months only. Figure III-12 illustrates the changes in surplus obtained in an average hour by each of the four groups of economic agents across the months of the study period. The related change in total surplus is illustrated in Figure III-13.

The average hourly data presented above can be transformed into monthly total data by multiplying by the number of hours in the appropriate month. The mean and standard deviation of these transformed data are reported in Table III-3. Figure III-14 illustrates the changes in monthly surplus obtained by each of the four groups of economic agents. The change in monthly total surplus is illustrated in Figure III-15.

The data reveal that the impact of the regulator’s policy of renewable energy procurement on both total surplus and its components has been growing through time.

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68 The data are reported on an hourly basis in the sense that they indicate changes in surplus for each hour in a month. Monthly total data must account for the total number of hours in each month.
Table III-2: Changes of surplus under the counterfactual policy
By economic agent on an hourly basis, in dollars
All months and last 24 months

<table>
<thead>
<tr>
<th>Economic Agent</th>
<th>All Months</th>
<th>Last 24 Months</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Mean</td>
<td>Std. Dev.</td>
</tr>
<tr>
<td>Ontario-based supply</td>
<td>5,499</td>
<td>7,670</td>
</tr>
<tr>
<td>Imports</td>
<td>1,025</td>
<td>1,275</td>
</tr>
<tr>
<td>Ontario-based demand</td>
<td>10,169</td>
<td>16,788</td>
</tr>
<tr>
<td>Export</td>
<td>-1,999</td>
<td>2,722</td>
</tr>
<tr>
<td>All agents combined</td>
<td>14,695</td>
<td>22,770</td>
</tr>
</tbody>
</table>

Table III-3: Changes of surplus under the counterfactual policy
By economic agent on a monthly basis, in millions of dollars
All months and last 24 months

<table>
<thead>
<tr>
<th>Economic Agent</th>
<th>All Months</th>
<th>Last 24 Months</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Mean</td>
<td>Std. Dev.</td>
</tr>
<tr>
<td>Ontario-based supply</td>
<td>4.004</td>
<td>5.559</td>
</tr>
<tr>
<td>Imports</td>
<td>0.747</td>
<td>0.922</td>
</tr>
<tr>
<td>Export</td>
<td>-1.456</td>
<td>1.977</td>
</tr>
<tr>
<td>All agents combined</td>
<td>10.704</td>
<td>16.538</td>
</tr>
</tbody>
</table>

This finding corresponds to the findings noted in the previous section regarding the impact of the policy on the wholesale market clearing price, the GA rate, the all-in price, and the various endogenously-determined quantities. It is consistent with the expectations regarding how the regulator’s policy would manifest itself, namely that the impact would gradually appear in the market as the generation procured entered service.

The results indicate that consumers located in Ontario faced a loss of surplus as a result of the procurement policy. The channel through which this loss was incurred was that
Figure III-12: Changes of surplus, by groups of economic agents, hourly basis

Figure III-13: Change of total surplus, hourly basis
Figure III-14: Changes of surplus, by groups of economic agents, monthly basis

Figure III-15: Change of total surplus, monthly basis
the all-in price increased as a result of the policy. The results also recognise losses of surplus incurred by non-contracted generators and importers as a result of a reduced wholesale market clearing price. Correspondingly, exporters gain surplus. In the context of the data presented, the losses discussed can be identified as the gains associated with the counterfactual policy relative to the base case while the gains discussed can be identified as the losses associated with the counterfactual policy relative to the base case.

In particular, over the whole study period, the analysis concludes that total surplus would have averaged $14,695 higher per hour under the counterfactual policy than the base case. Of this total, hourly surplus attributable to Ontario-based consumers, non-contracted generators, and importers would have averaged $10,169, $5,499, and $1,025 higher, respectively, while hourly surplus attributable to exporters would have averaged $1,999 lower. On an aggregate monthly basis, total surplus would have averaged $10.7 million higher under the counterfactual policy than the base case. Of this total, monthly surplus attributable to Ontario-based consumers, non-contracted generators, and importers would have averaged $7.4 million, $4.0 million, and $0.7 million higher, respectively, while monthly surplus attributable to exporters would have averaged $1.5 million lower.

Reflecting the implementation of the procurement programme through time, all of these averages are higher over the last 24 months of the study period than over the whole study period. In particular, over the whole study period, the analysis concludes that total surplus would have averaged $47,327 higher per hour under the counterfactual policy than the base case. Of this total, hourly surplus attributable to Ontario-based consumers, non-contracted generators, and importers would have averaged $34,229, $16,269, and $2,712 higher, respectively, while hourly surplus attributable to exporters would have averaged $5,883 lower. On an aggregate monthly basis, total surplus
would have averaged $34.5 million higher under the counterfactual policy than the base case. Of this total, monthly surplus attributable to Ontario-based consumers, non-contracted generators, and importers would have averaged $24.9 million, $11.8 million, and $2.0 million higher, respectively, while monthly surplus attributable to exporters would have averaged $4.3 million lower.

In aggregate, the results show that the procurement policy resulted in a reduction of total surplus of approximately $1,177.5 million from its commencement in 2006 through to June 2011. Of this total, the loss of surplus from Ontario-based consumers, non-contracted generators, and importers is reported to have been approximately $815.1 million, $440.4 million, and $82.2 million, respectively, while the gain in surplus by exporters is reported to have been $160.2 million.

The (net) loss of total surplus constitutes the social cost of obtaining the CO₂ emission reductions achieved as a result of the regulator’s renewable energy procurement policy. The amount of CO₂ emission reductions achieved is the subject of the next section.

3.4.3. Change of CO₂ emissions

The change of CO₂ emissions resulting from the regulator’s programme of renewable energy procurement is due to the change in composition of Ontario-based supply it causes. The reduction of electricity output that is generated through the combustion of fossil fuels is given by equation (III-7). The reduction of CO₂ emissions associated with this change of supply composition is given by equation (III-8).

Table III-4 reports the mean and standard deviation of the changes in CO₂ emissions under the counterfactual policy. The results are reported on an hourly—tonnes per hour—and a monthly—thousands of tonnes per month—basis. The statistics are presented for all 110 months of the study period and the last 24 months only. Figures
III-16 and III-17 illustrate the changes in average hourly and monthly emissions, respectively, across the months of the study period.

The results indicate that the impact of the regulator’s policy of renewable energy procurement on CO₂ emissions has been growing through time, a finding consistent with the expectations regarding how the regulator’s policy would manifest itself, namely that the impact would gradually appear in the market as the generation procured entered service.

In particular, over the whole study period, the analysis concludes that CO₂ emissions would have been an average of 63 tonnes per hour, equivalent to approximately 46 thousand tonnes per month, greater under the counterfactual policy than under the base case. Reflecting the implementation of the procurement programme over time, the analysis reveals that CO₂ emissions would have averaged 191 tonnes per hour, equivalent to approximately 139 thousand tonnes per month, more under the counterfactual policy than under the base case over the last 24 months of the study period.

In aggregate, the results indicate that the procurement policy resulted in a reduction of CO₂ emissions of approximately 5,076 tonnes from its commencement in 2006 through to June 2011. These are the CO₂ emissions that were abated as a result of the renewable energy procurement programme.

Table III-4: Change of CO₂ emissions, amount as noted, hourly and monthly basis
All months and last 24 months

<table>
<thead>
<tr>
<th>Basis</th>
<th>All Months</th>
<th></th>
<th>Last 24 Months</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Mean</td>
<td>Std. Dev.</td>
<td>Mean</td>
<td>Std. Dev.</td>
</tr>
<tr>
<td>Hourly (tonnes)</td>
<td>63.35</td>
<td>87.16</td>
<td>191.08</td>
<td>87.02</td>
</tr>
<tr>
<td>Monthly (thousands of tonnes)</td>
<td>46.14</td>
<td>63.17</td>
<td>139.10</td>
<td>62.11</td>
</tr>
</tbody>
</table>
Figure III-16: Change of CO₂ emissions, hourly basis

Figure III-17: Change of CO₂ emissions, monthly basis
3.4.4. Cost of CO$_2$ emission abatement

Having obtained estimates of the loss of total surplus related to the regulator’s programme of generation procurement, as well as estimates of the amount of CO$_2$ emissions thereby abated, the cost of CO$_2$ emission abatement can be estimated using equation (III-9). A modified version of equation (III-9) can be used in which the loss of surplus is the loss of surplus attributable to Ontario-based consumers alone rather than that of all economic agents combined.

Table III-5 reports the mean and standard deviation of CO$_2$ emission-abatement costs using total surplus and Ontario-based consumers’ surplus alone as the relevant social cost based on the assumption that it is natural gas-fuelled generation that replaces renewable energy under the counterfactual policy. Given that there was no CO$_2$ emission-abatement before the first renewable energy generator entered the market in March 2006, equation (III-9) is not meaningfully defined for all 110 months of the study period. It is, therefore, calculated only for the 64 months in which renewable energy generators were in the market. The statistics are presented for all 64 months in which equation (III-9) can be calculated and the last 24 months only. Figure III-18 illustrates CO$_2$ emission-abatement costs for both definitions of social cost for all relevant months.

Table III-6 and Figure III-19 report analogous results based on the assumption that it is coal-fuelled generation that replaces renewable energy under the counterfactual policy.

Under the assumption that renewable energy generators produced electricity that replaced natural gas-fuelled generation, the results indicate that the average cost of CO$_2$ emission-abatement as a result of the regulator’s programme was approximately $205.21 per tonne of CO$_2$. The slight upward-movement of this cost through time is likely a result of the slight upward-movement of the average contract price of
renewable generation, as illustrated in Figure III-3, to which the regulator is party. Approximately two-thirds of this cost ($132.83 out of $205.21 per tonne) is borne by Ontario-based consumers through a reduction of surplus resulting from the higher all-in price that prevails as a result of the programme. Notwithstanding this, the cost borne by the other economic agents is meaningful ($72.38 per tonne), indicating that failing to adequately account for the impact of the procurement programme on agents other than Ontario-based consumers will result in cost estimates that are too low.

Under the alternative assumption that renewable energy generators produced electricity that replaced coal-fuelled generation, the results indicate that the average cost
Figure III-18: Cost of CO₂ emission-abatement with renewable energy in place of natural gas

Figure III-19: Cost of CO₂ emission-abatement with renewable energy in place of coal
of CO₂ emission-abatement as a result of the regulator’s programme was approximately $92.11 per tonne of CO₂. As under the former assumption, the slight upward-movement of this cost through time is likely a result of the slight upward-movement of the average contract price of renewable generation to which the regulator is a party. Approximately two-thirds of this cost ($59.62 out of $92.11 per tonne) is borne by Ontario-based consumers through a reduction of surplus resulting from the higher all-in price that prevails as a result of the programme. As under the former assumption, the cost borne by the other economic agents is meaningful (approximately $32.49 per tonne) which indicates the importance of accounting for it.

To be clear, the analysis conducted thus far estimated the cost—a point estimate—of CO₂ emission-abatement for each month of the study period. The reported means in Tables III-5 and III-6 are the averages of these monthly values under the specified conditions. The standard deviation that is also reported measures the variability of these monthly values. While this is a useful measure of the stability of the monthly point estimates, it cannot be used to establish a confidence set around the point estimate. An alternative process that can achieve such an outcome is discussed in the next section.

**3.4.5. Bootstrapping the cost of CO₂ emission-abatement**

In order to establish confidence in the estimates of the cost of CO₂ emission-abatement associated with Ontario’s generation procurement programme, it would be useful to generate standard errors associated with the point estimates rather than point estimates alone. The process implemented in the previous sections did not allow for this outcome. However, the process can be used to construct the desired standard errors.

The results reported in the previous section are based upon using all 110 observations of market outcomes to estimate the model introduced in section 2 and subsequently the
hypothetical impact on the modelled base case of a counterfactual policy under which no renewable energy generators entered Ontario’s electricity market. A single point estimate of the cost of CO$_2$ emission-abatement was calculated.

Alternatively, the procedure described above could be repeatedly implemented using a bootstrapped sample, *i.e.*, a sample of 110 observations with replacement from the original data set. Each bootstrapped sample would result in a single point estimate of the cost of CO$_2$ emission-abatement (for each set of conditions such as replacement fuel, e.g., coal). The resulting set of point estimates would form a distribution. The mean of this distribution which would be taken to be the point estimate of the cost of CO$_2$ emission-abatement and the standard deviation would be taken to be its standard error.

Table III-7 reports the point estimate and standard error of the cost of CO$_2$ emission-abatement for both natural gas and coal as the replacement fuel. In each case there were 9,999 replications. The data underlying these estimates are illustrated in Figures III-20 and III-21. A sketch of a normal distribution is imposed on each figure.

The bootstrapped estimates of the cost of CO$_2$ emission-abatement reported in Table III-7 are similar to those reported in Tables III-5 and III-6. In particular, if natural gas is the

<table>
<thead>
<tr>
<th>Fuel Type</th>
<th>Mean</th>
<th>Std. Error</th>
</tr>
</thead>
<tbody>
<tr>
<td>Natural gas</td>
<td>207.23</td>
<td>17.18</td>
</tr>
<tr>
<td>Coal</td>
<td>93.01</td>
<td>7.71</td>
</tr>
</tbody>
</table>

Table III-7: Bootstrapped cost of CO$_2$ emission-abatement
Dollars per tonne of CO$_2$ ($/tonne)
Renewable energy in place of natural gas or coal
Based on total surplus

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69 The bootstrap procedure repeatedly samples the data with replacement and estimates both the base case model as well as the cost of emission-abatement. A superior technique involving sampling the errors associated with the model estimated in section 2 is left as future research.
Figure III-20: Distribution of cost of CO$_2$ emission-abatement, in $/tonne of CO$_2$ emission-abatement with natural gas as the replacement fuel

Figure III-21: Distribution of cost of CO$_2$ emission-abatement, in $/tonne of CO$_2$ emission-abatement with coal as the replacement fuel
generation fuel that renewable energy generation replaces in the supply mix, then the estimated cost of CO$_2$ emission-abatement is approximately $207 per tonne. If coal is the generation fuel that is replaced in the supply mix, then the estimated cost is approximately $93 per tonne. Both estimates are statistically significant. These are the estimates that the following discussion is based upon.

3.5. Discussion

The analysis contained in this paper indicates that the average cost of CO$_2$ emission-abatement is at least $93 per tonne (higher toward the end of the study period). This value assumes the electricity produced by Ontario’s portfolio of wind- and solar-fuelled renewable energy generators replaces that produced by coal-fuelled generators. If it is assumed that the electricity produced by renewable energy generators replaces that produced by natural gas-fuelled generators then the average cost of CO$_2$ emission-abatement is at least $207 per tonne (also higher toward the end of the study period).

These CO$_2$ emission-abatement cost estimates are consistent with estimates reported by others in the context of Ontario’s electricity market. For instance, in relation to the feed-in-tariff introduced in Ontario in 2009, Dewees (2010) estimates that the specified contract prices implied a value of CO$_2$ emission-abatement of $85 per tonne in the case of onshore wind-fuelled generators (which are Ontario’s dominate producer of non-hydroelectric renewable energy generation) replacing coal-fuelled generation. This compares to an estimate of $93 per tonne (standard error = 7.71) reported in this paper.

The channels through which these costs are incurred are important. As the analysis of changes of surplus under the counterfactual policy made clear, all groups of economic agents in the market were affected by the procurement policy. Not all of these groups, however, were adversely affected by the policy.
As the results reported in Table III-3 indicate, Ontario-based consumers, non-contracted generators, and importers were negatively affected by the policy. Ontario-based consumers were negatively affected because the all-in price they pay for electricity increased. Non-contracted generators and importers were negatively affected because the wholesale market clearing price they receive for their respective activities decreased.

Exporters, on the other hand, were positively affected by the policy. This was because the wholesale market clearing price they pay decreased.

Indeed, Table III-3 indicates that the loss of surplus attributable to non-contracted generators is greater than half the size of the loss of surplus attributable to Ontario-based consumers. It is useful to consider the nature of these generators, in particular, of their ownership. With the exception of a small number of hydroelectric generators, the non-contracted generators are owned by the provincial government through the crown corporation Ontario Power Generation (OPG).70 Therefore, this loss of surplus constitutes a loss to the people of Ontario through their provincial government.71

It is critical to make clear that the loss of surplus identified above does not account for the benefits obtained by CO$_2$ emission-abatement. Instead, it identifies the cost of the CO$_2$ emission-abatement. In evaluating the programme the relevant economic question is not whether these benefits are socially valuable. They are presumed to be socially valuable. Instead, the relevant economic question with respect to evaluating the programme is whether the benefits were obtained at lowest cost, that is, whether the programme was allocatively efficient. Answering this question requires a determination of what the lowest cost policy might be.

70 These generators were fuelled largely by coal, uranium (nuclear), and water (hydroelectric).
71 This loss can be observed in two related ways. First, the assets generate less profit for their shareholder on an on-going basis, the government of Ontario. Second, losses are capitalised in the form of reduced assets valuations.
Two possible policy constructs to which Ontario’s policy can be easily compared are the European Union Emissions Trading Scheme (EU ETS) and the Regional Greenhouse Gas Initiative (RGGI). The EU ETS is a useful benchmark because of the breadth of its application, both in terms of the number of industries subject to its terms and the number of countries in which it is applicable. The RGGI is a benchmark because it imposes a cost on generators for CO$_2$ emissions from electricity generators in the north-eastern United States, markets which are similar to Ontario’s in many ways and which routinely engage in electricity trading with Ontario.

Futures contracts for EU emission allowances trade on, among other places, the Intercontinental Exchange (ICE). Over the 2-year period ranging from April 2010 to April 2012, futures contracts for EU emission allowances have traded within a price range of €6-18 per tonne of CO$_2$ (approximately $8-24). Earlier it had traded as high as €30 per tonne of CO$_2$ (approximately $40).$72

The RGGI conducts quarterly auctions of emissions allocations. The highest observed auction clearing price occurred in March 2009 at a price of $3.51 per tonne of CO$_2$.$73

Given this information, it can be concluded that the average cost of CO$_2$ emission-abatement in Ontario’s electricity market, a minimum of $93 per tonne of CO$_2$ abated, is relatively high.

3.6. Conclusions

This section reported a formal analysis of the social cost of CO$_2$-emission abatement under Ontario’s programme of renewable energy generation capacity procurement.

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$^72$ For current (and some historical) data on futures contract prices for EU emission allowances, see ICE’s webpage at https://www.theice.com/productguide/ProductDetails.shtml?specId=197. For additional historical data, see Grubb et al. (2009).

$^73$ Historical RGGI auction market data is available at http://www.rggi.org/market/co2_auctions/results.
The reported results made clear the inadequacy of focusing on the effect of the programme on consumers alone. This necessitated the use of model of the market of the type introduced in section 2.

The analysis concluded that the cost of CO$_2$-emission abatement under Ontario’s programme is well in excess of the cost of CO$_2$-emission abatement in other jurisdictions and industries. This indicates that the same CO$_2$-emission abatement achieved in Ontario could have been achieved at substantially lower cost—or substantially greater CO$_2$-emission abatement could have been achieved at the same cost—under alternative policy constructs that exist elsewhere.

4. Conclusion

The analysis suggests that there are significant inefficiencies associated with Ontario’s programme of generation procurement. These inefficiencies manifest themselves in the form of the province paying a premium for renewable energy generation capacity that far exceeds the level necessary to achieve comparable environmental objectives in other markets. The result is that, among other things, (1) consumer prices for electricity are higher than their efficient level, (2) government-owned generation assets, in particular Ontario Power Generation, receive much less revenue and profit than their efficient level, thereby depriving Ontario’s provincial government of economic resources that could be expended for alternative purposes, (3) exports are inefficiently high, and (4) all of these effects are growing through time.

While the implications of past policy choices are unavoidable, future outcomes could be improved with policy changes. In particular, the effect of the renewable energy generation programme in the future would be lessened if the amount of generation subject to its terms ceased growing. Comparable environmental objectives could be achieved in other sectors of the economy, with surplus economic resources remaining
for other objectives, including, perhaps most importantly, significant additional carbon dioxide abatement.

Also, at the time of its introduction, the GA rate did not constitute a consistently positive and large proportion of the all-in price. However, the growing importance over time of the GA rate as a component of the all-in price of electricity can be interpreted as a shift away from incremental cost pricing towards average cost pricing, an outcome which has negative implications for the allocative efficiency of the wholesale market. This development also magnifies the importance of the rule used by the regulator to allocate its costs among consumers, an issue discussed at length in Olmstead (2012).
References


Appendices

Appendix II-A: Global adjustment reform of 2010

From its introduction on 1 January 2005 to 31 December 2010, inclusive, aggregate global adjustment was allocated to consumers as prescribed by Ontario Regulation 429/04. In short, during this time period the allocation rule was such that all Ontario-based consumers paid exactly the same rate in dollars per MWh. Exports were exempt from contributing to global adjustment costs. This rule was described in the main text.

Effective 1 January 2011, as per Ontario Regulation 398/10, the global adjustment allocation rule was changed. The new regulation distinguishes between two classes of consumers: A and B. Class A consumers are defined to be those Ontario-based consumers whose own monthly maximum hourly demand for electricity exceeds, on average, 5 MW during a predefined base period. For instance, in the case of the billing period from 1 January 2011 to 30 June 2011, the base period used to distinguish class A consumers was 1 May 2010 to 31 October 2010, i.e., class A consumers are those whose maximum hourly demand for electricity in May, June, July, August, September, and October 2010 exceeded 5 MW on average. All Ontario-based consumers who are not members of class A are defined to be members of class B. Consumers always

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74 The billing period is the period in which electricity is consumed.
75 It is necessary but not sufficient that maximum hourly demand exceed 5 MW in at least one month of the base period for a consumer to be defined as a being a member of class A. It is sufficient but not necessary that maximum hourly demand exceed 5 MW in all months of the base period for a consumer to be defined as being a member of class A. There are no restrictions or conditions regarding when in the relevant month the maximum hourly demand for electricity is observed nor how maximum consumption relates to average consumption.
76 Effective with the billing period beginning 1 July 2011, a billing period from 1 July of Year Y to 30 June of Year Y+1 corresponds to a base period from 1 May of Year Y-1 to 30 April of Year Y. Class A consumers must re-qualify as such on an annual basis.
77 For the billing period 1 January 2011 to 30 June 2012, Ontario-based consumers who meet the standard required to be members of class A may nonetheless opt to be treated as members of class B.
know in advance of their consumption choices to which class they belong.

Class A consumers are charged global adjustment based on coincident peak demand. This allocation mechanism is referred to as the coincident peak rule. Regarding this allocation mechanism, the IESO states

“[c]oincident peak means that [each consumer’s total global adjustment] costs are calculated based on the percentage that each customer’s demand contributes to overall provincial demand during the five peak hours of a base period. The peak hours are the five hours (occurring on different days) in which the greatest number of megawatts of electricity was used in Ontario” (IESO, undated, p.1).

Class B consumers will continue to be charged global adjustment in proportion to their total monthly consumption, i.e., they continue to pay a global adjustment rate determined as the aggregate global adjustment expenses divided by aggregate Ontario-based demand as implied by equation (II-5).

Notwithstanding the potential significance of this policy change on consumer behaviour, the coincident peak allocation rule applied to class A consumers is ignored in the analysis undertaken in this paper. There are several reasons for this choice.

First, the time period under study in this paper ends in June 2011, meaning that at most six out of 109 observations may be affected by the policy change. Associated with a policy change of this type is a learning and adjustment process that has just begun.

Second, Ontario Regulation 398/10 was filed on 22 October 2010. Prior to its publication, the government’s commitment to the particular details contained within the regulation, as well as the timing of publication itself, were not known with certainty. Given that the base period that determined which consumers were members of class A during the final six months (observations) of the data set covered the period from, as
stated above, 1 May 2010 to 31 October 2010 it is unlikely that class A contains many consumers whose maximum hourly consumption in a month would not have exceeded 5 MW on average, *i.e.*, the policy is unlikely to have altered the composition of class A. However, strategic behaviour in relation to this policy change is likely to become a significant issue subsequent to 30 June 2011.
Appendix II-B: Structure of global adjustment expenses

There is a number of different aspects of the regulator’s activities that contribute to costs that must be recovered through the GA mechanism. The process accounts for payments arising in relation to: (i) wind generation contracts; (ii) solar generation contracts; (iii) NUGs; (iv) nuclear facilities; (v) baseload hydro; (vi) natural gas capacity contracts; (vii) contingency payments to certain OPG-owned fossil generators; and (viii) OPA conservation programs. There may be particular exceptions to the structure of regulatory intervention described below. The typical case is considered.

After describing the contribution mechanism associated with each of the eight activities of the regulator, the regulator’s GA expense equation is written out.

Wind generation

Wind generation contracts specify a fixed price per unit of output for which wind-generated electricity is paid. Such contracts were labelled fixed-price contracts in the main body of the paper. It is assumed that the fixed price is $135/MWh. The nature of out-of-market top-up payments is such these generators receive the wholesale market clearing price for their output from the wholesale market and are subsequently paid the difference between the contract price (assumed to be $135/MWh) and that price. If the wholesale market clearing price were sufficiently high—above $135/MWh—then the top-up would be negative.

The aggregate amount of wind-fuelled electricity injected into the IESO-controlled transmission grid is observed on an hourly basis. These hourly data are averaged across the hours of the relevant month to generate the data used in this analysis. These data exclude the output of wind generators not connected to the IESO-controlled transmission grid, that is, those generators embedded in the distribution systems of
local distribution companies. As such generation constitutes a small component of aggregate wind generation in Ontario, these facilities are ignored.

**Solar generation**

Like wind generation contracts, solar generation contracts specify a fixed price per unit of output for which solar-generated electricity is paid. These are fixed price contracts. It is assumed that the fixed price is $420/MWh. The nature of the top-up payments associated with these contracts is analogous to wind generation contracts.

Solar-fuelled electricity production is not publically available. However, data regarding the level of aggregate capacity of solar installations within Ontario is available. These data are reported in “A Progress Report on Electricity Supply,” published on a quarterly basis by the OPA. For simplicity, it is assumed the production of electricity from solar generators is characterised by a fixed, 10% capacity factor.\(^{78}\)

**Non-utility generators (NUGs)**

Most NUGs are cogeneration facilities that produce electricity and are integrated into the production process of a non-electricity good. It is assumed that there is 1577 MW of NUG capacity that generates an average of $75/MWh in capacity and energy payments.

These assumptions may seem unreasonable, but even with them the simulated amount of out-of-market payments received by NUGs (and certain contingency payments, as discussed below) is less than the observed payments to NUGs. The mechanism can be thought of as being equivalent to the one that provides capacity payments to natural

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\(^{78}\) The mechanism described may overstate the out-of-market top-up payments made to solar generators since such output is positively correlated with the hourly wholesale market price. This is because solar generators produce their output during day-time hours due to the availability of the sun, which corresponds to the periods of greater demand and higher wholesale market clearing prices. Given the magnitude of the fixed price guaranteed to generators, this issue is likely to be of minor importance.
gas generators (as described below).

**Nuclear facilities**

All nuclear-powered generation facilities in Ontario are owned by Ontario Power Generation (OPG). The reactors located in Bruce County are operated under a long-term lease by Bruce Power, a private-sector firm.

It is assumed that this generation earns a fixed price of $55/MWh. This is a significant simplification: some generation is paid less, some more. The Bruce B generating facility is subject to a price floor under its average unit price. The nature of the top-up payments—which are often negative—is analogous to those under wind and solar generation contracts as described above.

Nuclear-powered generation data are available on a monthly basis from a number of sources, including the periodic reports of the Ontario Energy Board’s (OEB) Market Surveillance Panel (MSP) and the Independent Electricity System Operator (IESO).

**Baseload hydro**

OPG owns and operates the hydroelectric stations that produce electricity on the Niagara and St. Lawrence Rivers. It is assumed that the first 1900 MWh of hydro production in the average hour are paid $33/MWh. Wholesale market clearing prices in excess of this level result in OPG making contributions to the GA, while prices below this level result in OPG receiving payments from the GA. Output in excess of 1900 MWh earns the wholesale market clearing price and is assumed not to be subject to additional out-of-market top-up or claw-back payments, and is ignored in the calculation of regulator expenses recovered by the GA.

Nuclear-powered generation data are available on a monthly basis from a number of
sources, including the periodic reports of the Ontario Energy Board’s (OEB) Market Surveillance Panel (MSP) and the Independent Electricity System Operator (IESO).

**Natural gas capacity contracts**

The regulator’s programme of generation capacity procurement has, as of July 2011, induced the entry of more than 5000 MW of natural gas-fuelled generation capacity. Capacity payments, subject to certain claw-backs described below, are made to these generators.

Data regarding the commissioning of contracted natural gas capacity are reported in “A Progress Report on Electricity Supply,” published by the OPA. While this publication is released on a quarterly basis, it reports the formal date of commissioning of contracted natural gas generators. It is assumed that capacity support payments begin at that time. Thus, the amount of natural gas capacity is known on a monthly basis. It is also assumed that contracted capacity is paid an average of $7,900/MW-month. These contracts generally contain provisions under which the regulator takes back a portion of these capacity costs if the wholesale market electricity price exceeds a contractually-specified incremental cost of production, whereby the generator is deemed to have earned so-called net revenue—revenue in excess of incremental cost—in the wholesale market.\(^79\)

**Certain contingency payments**

As a result of the regulator’s programme of generation procurement, as well as due to

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\(^{79}\) Certain other contractual requirements must also be met. For instance, the wholesale market price must exceed the contractually specified incremental cost for a minimum duration for a facility to be deemed to have started. The contractually specified incremental cost, which includes a component related to operations and maintenance as well as a fuel component, may or may not correspond to a particular facility’s physical incremental cost. The basic principle is that the specified value of this term is beyond the control of the generator itself (after the contract with the regulator has been signed).
direct instruction from the provincial government, the fossil energy fuelled generators operated by OPG do not earn sufficient revenue in the wholesale electricity market to cover their variable costs. In order to prevent exit, out-of-market contingency support payments to OPG began in the first quarter of 2009.80

Quarterly data regarding the cost incurred as a result of this programme are available in the quarterly financial statements of OPG. The data are converted to a monthly frequency by dividing the quarterly data by 3.

**Conservation programs**

Aside from its program of generation procurement, the OPA has established a significant number of electricity conservation programs. The cost of these programs is recovered through the GA. Since these programs do not generate revenue in the wholesale electricity market the expenditures on them cannot be thought of as out-of-market top-up payments. Instead, such costs are viewed as constituting a fixed cost borne by the regulator.

Annual data regarding conservation spending are available for the years 2008, 2009, and 2010 in the annual reports of the OPA. To convert these data to a monthly frequency, annual data is divided by 12. Conservation spending before 2008 is ignored (and assumed to be zero), while spending for 2011 is forecast to have grown at the average growth rate of conservation spending over the year 2008 to 2009 and 2009 to 2010, with monthly data being one-twelfth of the 2011 forecast.

**Expense equation**

The sections above describe the mechanisms by which the eight activities of the

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80 Exit would be an undesirable outcome in the short term since the generators in question provide useful, at times necessary, support for the reliability of Ontario’s electricity market.
regulator contribute to GA expenses. These can be written as a single equation as

\[
\text{Exp}_t = q_{t}^{\text{wind}} \cdot (p_{t}^{\text{wind}} - P_t) + q_{t}^{\text{solar}} \cdot \text{solar}_{\text{capacity}} \cdot (p_{t}^{\text{solar}} - P_t) + q_{t}^{\text{nugs}} \cdot (p_{t}^{\text{nugs}} - P_t) + q_{t}^{\text{nuclear}} \cdot (p_{t}^{\text{nuclear}} - P_t) + q_{t}^{\text{base}_{\text{hydro}}} \cdot (p_{t}^{\text{base}_{\text{hydro}}} - P_t) + \text{nat}_{\text{gas}_{\text{capacity}}}_t + \text{contingency}_t + \text{conservation}_t
\]

(II-6)

where all data are converted to hourly averages. With the values that are fixed throughout the period of analysis substituted into equation (II-6), then

\[
\text{Exp}_t = q_{t}^{\text{wind}} \cdot (135 - P_t) + q_{t}^{\text{solar}} \cdot 0.19 \cdot (420 - P_t) + 1577 \cdot (75 - P_t) + q_{t}^{\text{nuclear}} \cdot (55 - P_t) + 1900 \cdot (33 - P_t) + \text{nat}_{\text{gas}_{\text{capacity}}}_t + \text{contingency}_t + \text{conservation}_t
\]

(II-7)
Appendix II-C: Solution to the model

The purpose of this appendix is to describe the process used to solve for the base case discussed in-text. The model of Ontario’s electricity market is composed of six equations with six endogenous variables and is discussed in detail in-text. The four estimable equations relate to Ontario-based supply, imports, Ontario-based demand, and exports, i.e.,

\[ q_t^s = \gamma_0 + \gamma_1 p_t + \gamma_2 fuel_t + \gamma_3 \text{baseload}_t + \varepsilon_{1t} \]  
\[ (II-1) \]

\[ q_t^l = \delta_0 + \delta_1 p_t + \delta_2 \text{NY}_L_t + \delta_3 \text{linked}_t + \varepsilon_{2t} \]  
\[ (II-2) \]

\[ q_t^d = \alpha_0 + \alpha_1 (p_t + g_t) + \alpha_2 \text{HDD}_t + \alpha_3 \text{CDD}_t + \alpha_4 M_{t-1} + \varepsilon_{3t} \]  
\[ (II-3) \]

\[ q_t^e = \beta_0 + \beta_1 p_t + \beta_2 \text{NY}_L_t + \beta_3 \text{linked}_t + \varepsilon_{4t} \]  
\[ (II-4) \]

The fifth equation is the regulator’s budget constraint, i.e.,

\[ g_t * q_t^d = q_t^{\text{wind}} \cdot (p_c^{\text{wind}} - P_t) + q_t^{\text{solar}} \cdot \text{solar} \cdot \text{capacity} \cdot (p_c^{\text{solar}} - P_t) \]
\[ + q_t^{\text{nugs}} \cdot (p_c^{\text{nugs}} - P_t) + q_t^{\text{nuclear}} \cdot (p_c^{\text{nuclear}} - P_t) \]
\[ + q_t^{\text{base,hydro}} \cdot (p_c^{\text{base,hydro}} - P_t) \]
\[ + \text{nat} \cdot \text{gas} \cdot \text{capacity}_t + \text{contingency}_t + \text{conservation}_t \]  
\[ (II-8) \]

The sixth equation is a quantity equilibrium condition, i.e.,

\[ q_t^d + q_t^e = (1 - \text{losses}) \cdot (q_t^s + q_t^l) \]  
\[ (II-9) \]

The solution to this system determines equilibrium Ontario-based supply, imports, Ontario-based demand, imports, the wholesale market clearing price, and the GA rate.

Once equations (II-1), (II-2), (II-3), and (II-4) have been estimated, fitted equations for
Ontario-based supply, imports, Ontario-based demand, and exports, can, as discussed in-text, be written as follows

\[ \hat{q}_t^s = \hat{y}_{ot} + \hat{r}_1 p_t \]  
\[ \hat{q}_t^i = \delta_{0t} + \delta_1 p_t \]  
\[ \hat{q}_t^d = \hat{a}_{0t} + \hat{a}_1 (p_t + g_t) \]  
\[ \hat{q}_t^e = \hat{\beta}_{0t} + \hat{\beta}_1 p_t \]

The quantity equilibrium condition, equation (II-9), can be re-written using the fitted variables as

\[ \hat{q}_t^d + \hat{q}_t^e = (1 - L) \ast (\hat{q}_t^s + \hat{q}_t^i) \]  

Substitution of equations (II-14), (II-17), (II-21), and (II-24) into equation (II-C-1) yields

\[ p_t = a_t - b_t g_t \]  

where

\[ a_t = \frac{(1 - L) \ast (\hat{y}_{0t} + \delta_{0t}) - (\hat{a}_{0t} + \hat{\beta}_{0t})}{[(\hat{a}_1 + \hat{\beta}_1) - (1 - L) \ast (\hat{y}_1 + \delta_1)]} \]  
\[ b_t = \frac{\hat{a}_1}{[(\hat{a}_1 + \hat{\beta}_1) - (1 - L) \ast (\hat{y}_1 + \delta_1)]} \]

and

\[ a_t > 0 \quad \text{and} \quad 0 < b_t < 1. \]

Proof that \( a_t > 0 \). Consider the numerator of equation (II-C-3). The terms \( \hat{a}_{0t} \) and \( \hat{\beta}_{0t} \) represent the horizontal intercepts of the Ontario-based demand and export curves, respectively, which are both positive by assumption. Thus, \( \hat{a}_{0t} + \hat{\beta}_{0t} > 0 \). The terms \( \hat{y}_{0t} \) and \( \hat{\delta}_{0t} \) represent the horizontal intercepts of the Ontario-based supply and import
curves, respectively, which are not necessarily positive. However, given that $0 < L < 1$, assuming $\tilde{p}_{ot} + \delta_{ot} < \tilde{a}_{ot} + \tilde{\beta}_{ot}$ implies that the numerator is negative, that is

$$(1 - L) \times (\tilde{p}_{ot} + \delta_{ot}) - (\tilde{a}_{ot} + \tilde{\beta}_{ot}) < 0 \quad (\text{II-C-5})$$

This condition can loosely be interpreted as requiring that the sum of the horizontal intercepts of Ontario-based demand and exports be greater than a positive fraction of the sum of the horizontal intercepts of Ontario-based supply and imports. If this was not the case then the wholesale market clearing price could not be positive. This condition is analogous to the standard assumption that the choke price in a market must exceed the marginal cost of the first unit of production for a market to exist.

Now consider the denominator of equation (II-C-3). The terms $\tilde{\alpha}_1$ and $\tilde{\beta}_1$ represent the inverses of the slopes of the Ontario-based demand and export curves, respectively, which are both negative by assumption, while the terms $\tilde{\gamma}_1$ and $\tilde{\delta}_1$ represent the inverses of the slopes of the Ontario-based supply and import curves, respectively, which are both positive by assumption. That is, $\tilde{\alpha}_1 < 0$, $\tilde{\beta}_1 < 0$, $\tilde{\gamma}_1 > 0$, and $\tilde{\delta}_1 > 0$. As noted in-text, $0 < L < 1$. Thus

$$(\tilde{\alpha}_1 + \tilde{\beta}_1) - (1 - L) \times (\tilde{\gamma}_1 + \tilde{\delta}_1) < 0 \quad (\text{II-C-6})$$

Therefore $\alpha_t > 0$. As an aside, consider the equilibrium that would obtain if the regulator’s budget constraint did not exist, that is, in a five-equation model of the electricity market. First, $g_t = 0$. Second, all payments made by the regulator that are funded by the GA, including out-of-market top-up payments, would have to be funded from elsewhere in the economy, say, by the levying of a non-distortionary tax by the government. In this revised model, $a_t (> 0)$ would be the equilibrium wholesale market clearing price.

Proof that $0 < b_t < 1$. From the argument above, it can be stated that
\[ 0 > \hat{\beta}_1 - (1 - L) * (\hat{\gamma}_1 + \hat{\delta}_1) \]

\[ \iff 0 > \hat{\alpha}_1 > (\hat{\alpha}_1 + \hat{\beta}_1) - (1 - L) * (\hat{\gamma}_1 + \hat{\delta}_1) \]

Noting that \((\hat{\alpha}_1 + \hat{\beta}_1) - (1 - L) * (\hat{\gamma}_1 + \hat{\delta}_1) < 0\), then

\[ 0 < \frac{\hat{\alpha}_1}{(\hat{\alpha}_1 + \hat{\beta}_1) - (1 - L) * (\hat{\gamma}_1 + \hat{\delta}_1)} < 1 \]

\[ \iff 0 < b_t < 1 \quad \text{(II-C-7)} \]

The regulator’s budget constraint, equation (II-8), can be re-written using the fitted variables as

\[ g_t * q^d_t = CGR_t - P_t * q^{ga}_t \quad \text{(II-C-8)} \]

where

\[ CGR_t = p^\text{wind}_c * q^\text{wind}_t + p^\text{solar}_c * q^\text{solar}_t * \text{solar_capacity} \]

\[ + p^\text{nugs}_c * q^\text{nugs}_t + p^\text{nuclear}_c * q^\text{nuclear}_t + p^\text{base_hydro}_c * q^\text{base_hydro}_t \]

\[ + \text{nat_gas_capacity}_t + \text{contingency}_t + \text{conservation}_t \quad \text{(II-C-9)} \]

and

\[ q^{ga}_t = q^\text{wind}_t + q^\text{solar}_t * \text{solar_capacity} + q^\text{nugs}_t + q^\text{nuclear}_t + q^\text{base_hydro}_t \quad \text{(II-C-10)} \]

The term \(CGR_t\), an acronym for contracted generator revenue, represents the total revenue received from all sources by generators operating under a contract with the regulator that may give rise to payments funded by the global adjustment. As such, it is the product of each generator-type’s contract price and total amount of output (across all firms), summed across all of the generator types, plus certain other expenses incurred by the regulator. The term \(q^{ga}_t\) represents the total amount of electricity
generated by all such generators. This quantity multiplied by the wholesale market clearing price, that is, \( P_t \times q_t^{ga} \), equals the amount of revenue contracted generators made in the wholesale market alone. The difference between these two amounts, which, as discussed in-text does not have to be non-negative, is the total amount of revenue received by contracted generators from sources other than the wholesale market. Since the only other source is the regulator, this term is equivalent to the amount of revenue raised by the regulator, that is, \( g_t \times q_t^d \). This relationship is summarised by equation (II-C-8).

Using equation (II-21), equation (II-C-8) can be re-written as

\[
g_t \times (\hat{a}_{ot} + \hat{a}_1 (p_t + g_t)) = CGR_t - P_t \times q_t^{ga}
\]  

(II-C-11)

As a result of these operations, the original six-equation system of equations can be solved for a system of two equations, equations (II-C-2) and (II-C-11), with two unknowns, the wholesale market clearing price and the GA rate. Due to the regulator’s budget constraint being quadratic in the GA rate, the system is not linear in nature. Instead, there will be two solutions. Substituting equation (II-C-2) into equation (II-C-8) yields a single equation that is quadratic in the GA rate, \( g_t \)

\[
[\hat{a}_1 (1 - b_t)]g_t^2 + [\hat{a}_{ot} + a_t \hat{a}_1 - b_t q_t^{ga}]g_t + [a_t q_t^{ga} - CGR_t] = 0
\]  

(II-C-12)

Therefore

\[
g_t = \left[ -B_t \pm \sqrt{(B_t)^2 - 4A_tC_t} \right] / 2A_t
\]  

(II-C-13)

where

\[
A_t = \hat{a}_1 (1 - b_t) < 0
\]  

(II-C-14)

\[81\] Recalling that \( \hat{a}_1 < 0 \) and \( 0 < b_t < 1 \), it follows immediately that \( A_t = \hat{a}_1 (1 - b_t) < 0 \).
\[ B_t = \hat{\alpha}_{0t} + a_t \hat{\alpha}_1 - b_t q_t^{ga} \]  \hspace{1cm} (II-C-15) 

and

\[ C_t = a_t q_t^{ga} - CGR_t \]  \hspace{1cm} (II-C-16) 

The term \( C_t \) is not explicitly signed. The sign, however, is important as it indicates whether the GA rate is negative or positive. To see why, consider equation (A-9)

\[ CGR_t = p_c^{wind} \cdot q_t^{wind} + p_c^{solar} \cdot q_t^{solar} \cdot solar\_capacity \]

\[ + p_c^{nugs} \cdot q_t^{nugs} + p_c^{nuclear} \cdot q_t^{nuclear} + p_c^{base\_hydro} \cdot q_t^{base\_hydro} \]

\[ + nat\_gas\_capacity_t + contingency_t + conservation_t \]  \hspace{1cm} (II-C-9) 

\[ = p_c^{average} \cdot q_t^{ga} \]

\[ + nat\_gas\_capacity_t + contingency_t + conservation_t \]  \hspace{1cm} (II-C-17) 

where

\[ p_c^{average} = p_c^{wind} \cdot \frac{q_t^{wind}}{q_t^{ga}} + p_c^{solar} \cdot \frac{q_t^{solar}}{q_t^{ga}} \cdot solar\_capacity \]

\[ + p_c^{nugs} \cdot \frac{q_t^{nugs}}{q_t^{ga}} + p_c^{nuclear} \cdot \frac{q_t^{nuclear}}{q_t^{ga}} + p_c^{base\_hydro} \cdot \frac{q_t^{base\_hydro}}{q_t^{ga}} \]  \hspace{1cm} (II-C-18) 

is a quantity-weighted average of the contract prices.

Substituting equation (II-C-17) into equation (II-C-16), then

\[ C_t = q_t^{ga} \left( a_t - p_c^{average} \right) \]

\[ - \left( nat\_gas\_capacity_t + contingency_t + conservation_t \right) \]  \hspace{1cm} (II-C-19) 

The term \( nat\_gas\_capacity_t + contingency_t + conservation_t \) is positive since each of
its components is positive by definition. Now consider the term \( (a_t - p_c^{average}) \). The variable \( a_t \), as noted above, is the wholesale market equilibrium price that would prevail if \( g_t = 0 \). Thus, if \( a_t < p_c^{average} \), then the weighted average of contract prices exceeds the wholesale market clearing price that would prevail if \( g_t = 0 \). As a result, contacted generators are not, on average, able to make sufficient revenue in the wholesale market alone to satisfy the contracts and would therefore be entitled to positive (average) out-of-market top-up payments. The amount of such payments, aggregated across all contracted generators, is the negative of the first term of equation (II-C-19). Thus, \( a_t < p_c^{average} \) is a sufficient (but not necessary) condition for \( C_t < 0 \). This is expected to be the case when relatively expensive generation types are weighted relatively highly in equation (II-C-18).

If \( a_t > p_c^{average} \), then the weighted average of contract prices is less than the wholesale market price that would prevail if \( g_t = 0 \). As a result, contracted generators, on average, make more revenue in the wholesale market alone than is required to satisfy the contracts and would therefore be required to rebate the excess to the regulator in the form of negative (average) out-of-market top-up payments. The amount of such payments, aggregated across all contracted generators, is the first term of equation (II-C-19). Due to the term \( (nat\_gas\_capacity_t + contingency_t + conservation_t) \), this alone does not guarantee that \( C_t > 0 \), but it is a necessary condition. That is, \( g_t > 0 \) may be necessary even if \( a_t > p_c^{average} \) if regulator expenses related to certain other expenses are sufficiently large.

Equation (II-C-13) has two solutions. That is, there are two GA rates that allow equilibrium to obtain in the wholesale market, including the balancing of the regulator’s budget. In order to maximise social welfare, the GA rate that is chosen is the one relatively small in absolute value. The rationale for this choice is that it, by definition, imposes the smallest distortion on the market. Denote this value as \( g_t^* \).
The equilibrium wholesale market clearing price, denoted as \( p_t^* \), is found by substituting \( g_t^* \) into equation (II-C-2). That is

\[
p_t^* = a_t - b_t g_t^* \tag{II-C-20}
\]

The equilibrium Ontario-based supply, imports, Ontario-based demand, and exports can be found by substituting \( p_t^* \) and \( g_t^* \) into equations (II-14), (II-17), (II-21), and (II-24), respectively.

\[
\hat{q}_t^s = \hat{y}_{0t} + \hat{y}_1 p_t^* \tag{II-C-21}
\]

\[
\hat{q}_t^i = \hat{\delta}_0 + \hat{\delta}_1 p_t^* \tag{II-C-22}
\]

\[
\hat{q}_t^{d*} = \hat{\alpha}_0 + \hat{\alpha}_1 (p_t^* + g_t^*) \tag{II-C-23}
\]

\[
\hat{q}_t^{e*} = \hat{\beta}_0 + \hat{\beta}_1 p_t^* \tag{II-C-24}
\]

The values \( p_t^*, g_t^*, \hat{q}_t^s, \hat{q}_t^i, \hat{q}_t^{d*}, \) and \( \hat{q}_t^{e*} \), constitute the base case equilibrium of the wholesale market model.