What Goes Up…
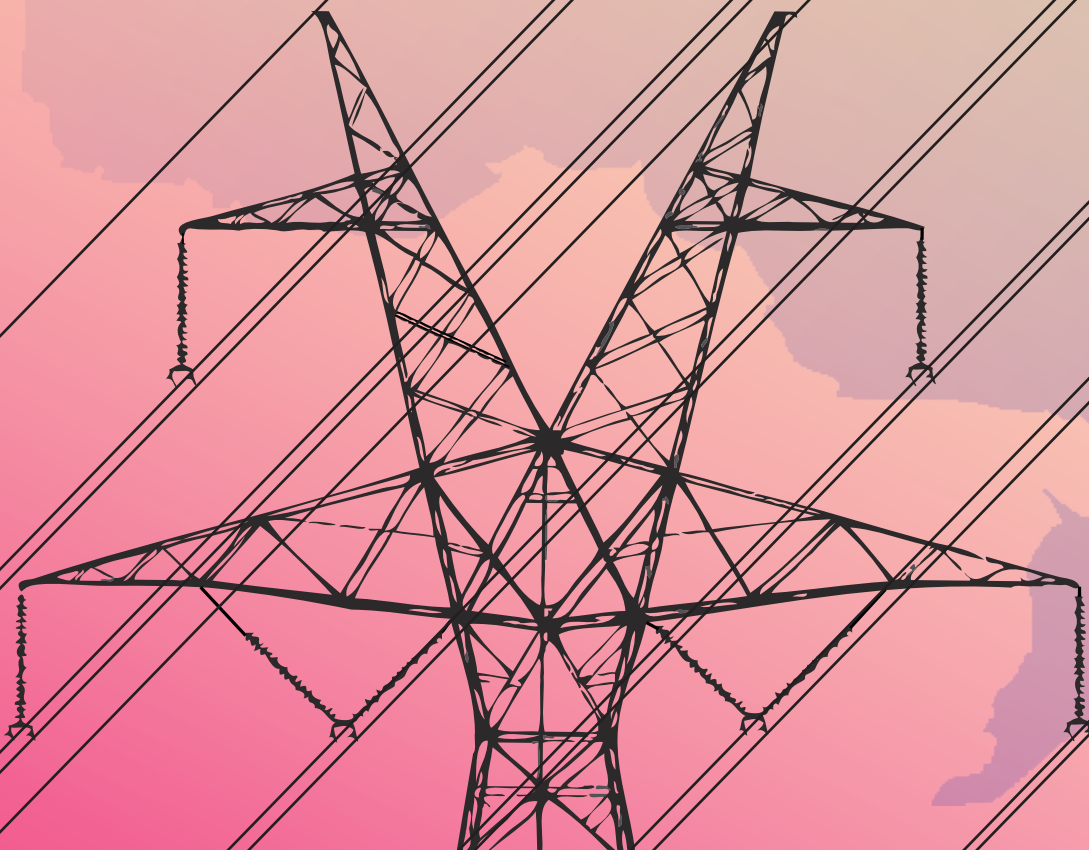
Ontario's Soaring Electricity Prices and How to Get Them Down

by Ross McKitrick and Tom Adams

October 2014

40 YEARS
1974 – 2014

FRASER INSTITUTE

What Goes Up: Ontario's Soaring Electricity Prices and How to Get Them Down

by Ross McKitrick and Tom Adams

Contents

Executive summary

The costs of running Ontario's power system have risen much more rapidly than inflation in recent years, despite a decline in competitive wholesale market prices for power. Of the major components of electricity rates, commodity costs are rising fastest, and are the focus of this study.

The commodity portion of Ontario electricity prices is comprised of a competitive market-clearing component (the Hourly Ontario Electricity Price or HOEP) and a centrally planned surcharge, now called the Global Adjustment (GA), that directs funds to generating units based on revenue contracts with the Province. Over the past decade, the market-clearing component has fallen to a relatively small component of Ontario electricity prices, while the centrally planned surcharge has risen six-fold—from a credit of about $10 per MWh to about $60 per MWh (6 cents per kWh). While the market-clearing component closely tracks neighbouring markets, the centrally planned costs are unique to Ontario. The centrally planned component of Ontario's power costs has become the dominant allocation mechanism in Ontario electricity pricing, which in turn means that relatively little of Ontario's electricity market is guided by competitive market price signals.

To understand why Ontario electricity prices are rising, we need to explain what drives the centrally planned Global Adjustment. One complicating factor is that some new renewable and non-renewable generators are paid not only based on their outputs but also based on their total capacities. Consequently our analysis looks at both capacity development and actual power generation.

After describing the GA, we develop an econometric model to determine the key system elements that drive the level of the Global Adjustment. We gather monthly data spanning 2005 to 2013 on the GA, the HOEP, capacity and output by generator type (wind, gas, solar, nuclear, hydro, and coal), and exports and imports. As a simple focus on direct cash flows to various generators would fail to account for the interactions between different components of the generation mix, we constructed a multiple regression model of the GA as a function of these explanatory variables. The model presented here explains close to 90 percent of the variance in the GA over the sample period.

The results are as follows:

1 We estimate that solar and wind systems provide just under 4 percent of Ontario's power but account for about 20 percent of the average commodity cost. By comparison, the Ontario Energy Board (2013) forecast that, in 2014, solar and wind would produce 7 percent of total supply and their direct costs would account for about the same fraction of the average commodity cost.

2 Each additional 1 MW of new wind capacity adds about $0.02/MWh to the Global Adjustment, after taking into account the offsetting effect of revenues from wind production. The system-wide cost effect is about 3.6 times the direct Feed-in-Tariff (FIT) payment burden.

3 Each additional MW of new hydro over the past decade has added about $0.015/MWh to the GA. Factors behind the deteriorating performance of hydroelectric generation warrant further investigation.

4 Solar power generation has large marginal effects on the GA, which have been concealed by the relatively minimal amounts generated so far in the province. An increase of 1 MWh per hour, on average over a month, will cause the GA for that month to rise by about $0.016/MWh.

5 Reductions in coal-fired power generation in Ontario were associated with statistically significant increases in the GA.

6 Imports can potentially reduce the GA, but exports occur under circumstances that increase it. Ontario is a large and growing power exporter. Encouraging greater domestic consumption at times of surplus baseload would reduce power costs in Ontario.

We recommend measures such as a moratorium on new renewable power facilities, pursuit of regulatory and legislative options to reduce the amount of installed renewables capacity, restarting 4 of 12 coal-burning units at Lambton and Nanticoke that can operate as cleanly as natural gas plants, suspending conservation programs when the province has surplus baseload, and exploring the option of large-scale imports of power from Hydro Quebec to bridge the interval for nuclear power plant refurbishment.

1. Introduction

1.1 Price shock

For about a decade, electricity prices in Ontario have been rising faster than inflation, and are officially forecast to continue doing so. This report analyses the reasons why this is the case, and asks whether there are options available that can put the province onto a trajectory back towards lower power prices. We examine the structure of Ontario's electricity pricing system, focused on the distinction between the competitive settlement price (the Hourly Ontario Electricity Price or HOEP) and the so-called "Global Adjustment" (GA), a side-payment that provides generators with revenue guarantees set by the provincial government. The wholesale price of electricity has not risen in the past decade—indeed, it has declined, consistent with trends in neighbouring markets. The GA, however, has risen from about minus $10 per mega-watt-hour (MWh) in 2005 to about $60/MWh today, or 6 cents per kWh. As recently as 2004, the entire industrial rate in Ontario was approximately equal to the current cost of just the GA component of rates. The increase in the GA over and above offsetting declines in the HOEP is the cause of rising electricity bills. We present a detailed econometric analysis of the key explanatory variables driving the GA.

1.2 Market structure and interaction effects

As originally designed, Ontario's competitive electricity market was to be an "energy-only" market, meaning that generators were to be paid per unit based on their electricity output. This stands in contrast to a "capacity market," in which generators are contracted to make a certain level of generating capacity available on-call, and in return get revenue guarantees from the government. Under increasingly active political guidance, Ontario has transitioned into an opaque hybrid system in which side-deals, net revenue requirements, and payments for "deemed production" introduce capacity-type arrangements. These payments create a complex web of interactions in which changes in

one part of the system can have large, indirect effects elsewhere. A proper analysis of the drivers of the GA must take these interactions into account.

For example, the introduction of a new 100 MW wind turbine facility has a direct cost that can be computed by taking the average output level of the wind farm and multiplying it by the difference between the HOEP and the guaranteed volumetric rate. The contracts underpinning the wind power in service today mostly derive from the Renewable Energy Supply agreements, but projects funded through feed-in tariff (FIT) will soon form the large majority. These payments get added to the Global Adjustment. But there are interaction effects between generators that influence overall consumer cost and must also be taken into account. For instance, wind turbine operators can bid into the market at low (and even negative) prices because of their revenue guarantee, which drives down the wholesale price across the market, increasing the gap between what other generators are paid and the revenues they were guaranteed by the province. The addition of new wind capacity exacerbates this distortion, creating a second-order effect on the GA. We will show that these interactions are likely larger than the direct costs themselves. Some previous analyses of rising Ontario prices have erred by failing to track capacity effects and the interactions they create across sources.[1] Our model will allow us to compute these interaction effects in a transparent way.

Two types of capacity expansions are explicit in the Ontario pricing system: hydro and gas. New hydro facilities have a very large marginal effect on the GA, reflecting the fact that the best sites for hydro generation were exploited decades ago, and the province's drive to expand capacity at less favourable sites has been very costly.

Our analysis will show that indirect system-wide interactions substantially increase the cost of renewable energy to electricity consumers, over and above the amount required to fund direct payments to renewable generators. In the next section, we review the recent history of Ontario's power pricing system, focusing on the way that a series of policy decisions has largely wiped out competitive price signals and replaced them with a non-market-based, non-transparent formula through the GA. We then introduce the econometric analysis and explain the results.

---

1. An example is Chee-Aloy and Stevens (2014).

2. Ontario's electricity pricing system

2.1 Cost trends

Ontario's overall inflation-adjusted electricity rates were stable for a sustained period, but they have been rising since 2006 and are officially forecast to continue doing so in the near term. Electricity bills charge for the commodity itself (energy) as well as for distribution, transmission, a tax called the Debt Retirement Charge, wholesale market services, and conservation program costs (ordered by cost impact).

In 2013, 61 percent of the total cost of electricity in Ontario was associated with the commodity portion, and of all the major bill segments this one is increasing the fastest.[2]

Figure 1 shows the recent history of the two components of the commodity cost, the Hourly Ontario Electricity Price (HOEP) and the Global Adjustment (GA), both adjusted for inflation. The HOEP is the wholesale spot market price determined by demand and supply conditions throughout the day. The GA is a rate adjustment mechanism used to fund revenue guarantees to power generators, and other non-market interventions imposed by the government. We explain the HOEP in further detail in Section 2.2, and the GA in Section 2.3. It is clear that the GA, rather than the HOEP, is driving the increase in electricity rates, so it will be important to explain the key drivers of each component separately.

The sum of the two components briefly spiked in 2005–06, reflecting a surge in wholesale power prices at the time, driven by a spike in natural gas prices and high demand. The total commodity cost then fell back to normal levels, after which a steady increasing trend set in. This increase has occurred despite relatively low natural gas prices (except in 2008) and a general trend toward lower usage. Below, we discuss some of the policy decisions that were made over the ensuing decade. Note that while the HOEP did fall after 2008, that decline was more than offset by an increase in the GA.

---

2. Ontario Power Authority, 2013, *Cost of Electricity Service 2013 Long Term Energy Plan*: Module 4, Slide 47. <http://powerauthority.on.ca/sites/default/files/planning/LTEP-2013-Module-4-Cost.pdf>

Figure 1

**Real Global Adjustment, Hourly Ontario Electricity Price, and sum, 2005 to present**
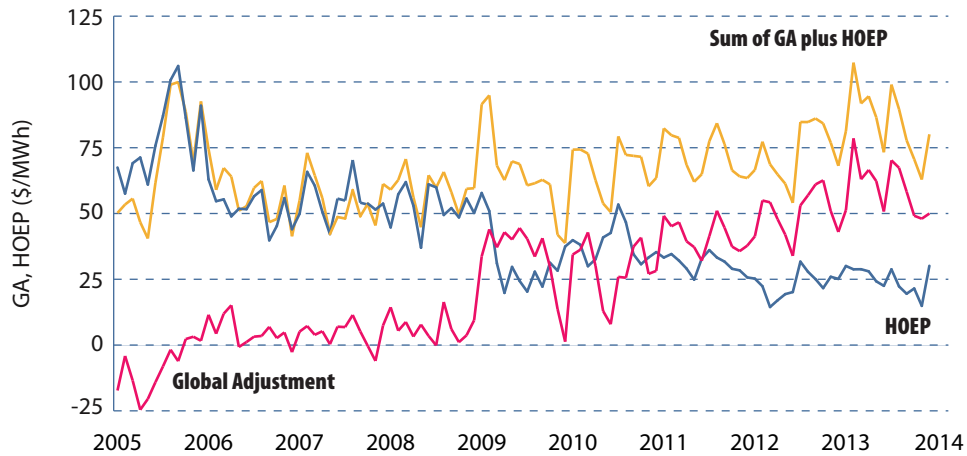
Note: Inflation-adjusted so ending value coincides with nominal.

Source: ieso.org.

In order to summarize the overall impetus towards higher electricity costs after 2005, **figure 2** shows the average annual system revenue requirement per unit of output on an annual basis from 2004 to 2016 (the forecast years being based on the Ontario Power Authority's near-term rate outlook). This simply shows the amount of money the Ontario electricity system must recover, per MWh, on average over a year. The data are drawn from various publications of the Ontario Power Authority (see methodology discussion in Appendix 1). The impact of the Ontario Clean Energy Benefit (OCEB), which was implemented starting in 2011, is removed from these figures, since it is merely a transfer from taxpayers to households, but does not affect the system revenue requirements.

From 2004 to the present, revenue requirements rose by over 50 percent, from about $90 to about $140 per MWh. With wholesale commodity prices falling from about $60 to about $25, there was clearly the basis for substantial losses to develop somewhere in the system. As we will explain, the GA has developed as a mechanism for covering these losses. It is important to note, however, that the GA is not set based on competitive pricing behaviour; instead it is heavily influenced by policy decisions that guarantee generators either a return on each unit produced or a return on capacity. Consequently, as the shale gas revolution has pushed fuel (and power) prices downwards in the US over the past decade, this has not led to reductions in either system revenue requirements or all-in prices for Ontario consumers. Instead, increases in the Global Adjustment have more than outstripped the reductions in the HOEP, leading to higher overall unit costs.

Figure 2

Total system revenue requirements per MWh, 2004–16
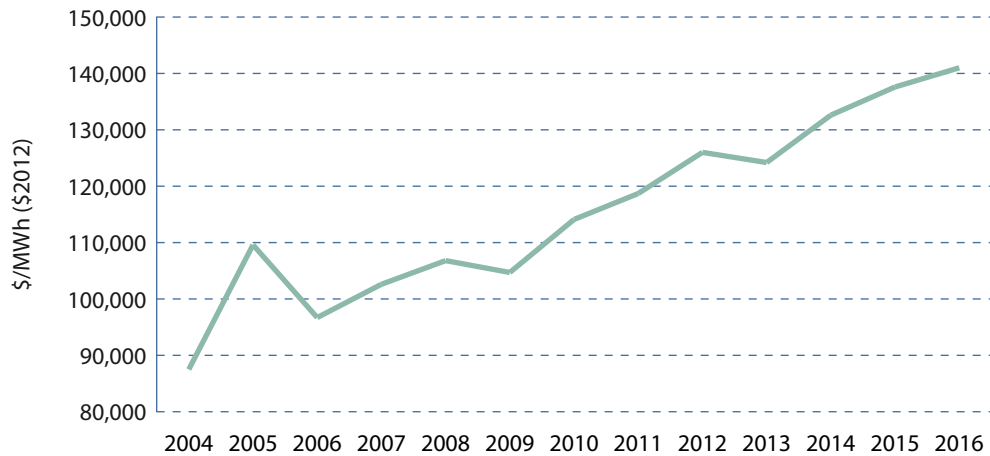
Source: See Appendix 1.

Figure 3 presents the trend in inflation-adjusted, before tax/OCEB power rates over the period 2004–2013. Starting in 2011, the Ontario government allowed select large industrial customers—the so-called Class A customers—to shift a portion of the cost of power to non-select industrial and non-industrial customers—the so-called Class B customers. This is accomplished through allocating the GA to the respective classes using peak demand as the allocation factor for Class A and energy usage as the allocator for Class B. The shift shows up as the forked rate trajectory line for industrial users in figure 3. Some of the rate increases experienced by residential and commercial customers, shown in figure 3, are attributable to this cost shift.

By 2013, commercial power rates in Ontario exceeded those of Nova Scotia, the next most costly province.[3] Ontario's residential rates, excluding the effect of the OCEB, were exceeded in 2012 (the most recent year available for comparison) only by weighted average residential rates in Alberta[4] and Nova Scotia.[5]

.

---

3. Based on the 2013 edition of Hydro Quebec's *Comparison of Electricity Prices in Major North American Cities*, although we have excluded Alberta from the comparison because the Hydro Quebec study does not provide a weighted average price reflective of the province at large.

4. Based on the report of the Alberta Retail Market Review Committee, *Power for the People*, September 2012, Figures 20–23.

5. 2012 edition of Hydro Quebec's *Comparison of Electricity Prices in Major North American Cities*.

Figure 3

Inflation-adjusted before-tax/OCEP power rates by customer class, Ontario, 2004–13
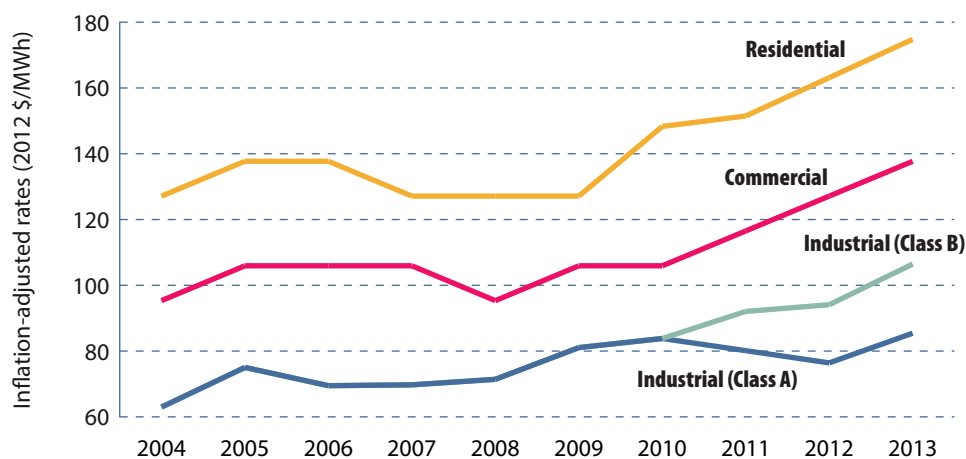
Source: See Appendix 2.

2.2 Hourly Ontario Electricity Price (HOEP)

The HOEP has, in recent years, constituted a declining fraction of Ontario's overall electricity revenue requirement. It has evolved from its historical origins through a series of policy changes. With the passage in 1998 of the Energy Competition Act, the Ontario government of the day replaced Ontario Hydro with what was then intended to be a competitive market for commodity electricity. The market design centred around a 5-minute auction-based price for electricity, with offers from generators to sell and bids from wholesale consumers to buy. The market was to be administered by the predecessor of the Independent Electricity System Operator (IESO), then called the Ontario Independent Market Operator. The resulting 5-minute prices were aggregated into the HOEP, which was used for settling most of the transactions in the market. The design of the market was intended to encourage generators to bid their short run marginal opportunity cost of producing increments of supply. In the event of supply shortfalls relative to demand, prices were expected to increase just high enough to ration demand to bring it in line with available supply.

Prior to and within about a year of the market opening in May 2002, policy changes with respect to both supply and demand started to erode the central role of the HOEP as originally envisioned for the new market. Three examples of these policy changes were: the Government's decision to introduce a price guarantee for certain industrial customers prior to market opening; a freeze on residential prices in November 2002; and a government program administered by a Crown corporation (Ontario Electricity Financial

Corporation, OEFC) to rent a fleet of power generators in 2003 when a period of tight supply was anticipated.

In 2004, the Ontario Power Authority (OPA) was established with the passage of the Electricity Restructuring Act, legislation that enshrined a hybrid market structure. The concept of the hybrid market was that the IESO-administered HOEP would continue to operate but that a parallel system would also operate consisting of a set of long term contracts or similar arrangements with generators administered either by the OPA or the Ontario Energy Board. The power system would be operated using the real-time auction process, but where contracted prices differed from the floating spot price, generators holding contracts or regulatory orders would be able to settle that difference with the OPA and the IESO, with those costs passed on to consumers.

Ensuing policy changes brought more and more generators into the contracted and regulated generation portfolio. Finally, in November 2013 a regulatory amendment, O. Reg. 312/13, was passed into law shifting the last significant portfolio of power generation within the province from receiving payment for their output based entirely on HOEP to receiving payment by way of administered prices. OPG's unregulated, non-contracted hydroelectric facilities, which constitute almost 3 GW of generation and are located on rivers other than the Niagara and St. Lawrence, represented the last significant generators in Ontario that had been financially dependent on HOEP.[6]

As of today, all generators in the Ontario market are contracted and the HOEP is consigned to a residual settlement role with no impact on long-term generator incentives.

2.3 Global Adjustment (GA)

The GA is a large and rapidly growing component of Ontario's overall electricity revenue requirement, reflecting mostly the difference between average market prices in the long-term government-directed procurement contracts and HOEP. Like the HOEP, the GA has transitioned from its historical origins through many policy changes.

When Ontario Hydro's generation assets were transferred to Ontario Power Generation (OPG), most of Ontario Hydro's liabilities were transferred to the OEFC under a structure called the Market Power Mitigation Agreement. Relieved of its debt, OPG was required to rebate customers for the difference between the market price and a negotiated price reflecting the forecasted cost of producing power from all of OPG's nuclear generators and its largest hydroelectric assets, located on the Niagara and St. Lawrence

---

6. <http://www.ontariocanada.com/registry/view.do?postingId=14082>

rivers. OPG was guaranteed a steady price per unit of production. The price per unit of production for regulated facilities was set at \$38/MWh, a figure based on the expected long-run cost including a rate of return on assets of the underlying generation portfolio. As originally designed, if market prices rose above \$38/MWh, OPG was to pay a rebate to consumers. The Market Power Mitigation Agreement was designed to encourage OPG to maximize output, to privatize generation, and to encourage competition in the market place while mitigating consumer cost.

In 2005, with the competition objective politically out of favour, the OPG rebate mechanism was incorporated into the Provincial Benefit (PB) as part of the set of market and pricing reforms that created the hybrid market. As illustrated in figure 1, until 2006 the OPG rebate component of the PB was large enough that the net effect was a consumer credit.

Starting at the beginning of 2011, the PB was transitioned into the GA. The calculation methodology for determining the GA was the same as the methodology underpinning the PB, albeit additional items were added to GA. However, the allocation of cost recovery responsibility was split between Class A (specified large industrial customers) and Class B (residual customers), resulting in a transfer of costs from Class A to Class B. The GA cost transfer was intended to shield targeted consumers from some of the cost consequences driving up the overall revenue requirement, although the change was justified publicly as primarily a conservation initiative.

Today, the GA is administered by the Ontario Electricity Financial Corporation, the OPA, and the IESO. We present the official GA formula in **box 1**. The legal language is somewhat obscure but in essence it divides energy transactions into four groups, identifies the statutory revenue guarantees for each, subtracts the respective market earnings, and then sums them all up. This amount is then recovered the following month by adding a surcharge to power bills in the form of the GA. The generation portion of the GA recovers costs for OPA-contracted generation, OEB-regulated generation, and generation contracts entered into by the former Ontario Hydro now administered by the OEFC. Of these, most GA costs arise from contracts the OPA has with generators. Some of these contracts are at fixed prices per unit of deemed output—a structure applied to wind and solar contracts. The OPA also has contracts with generators, including most gas-fired capacity, where the generator receives a monthly revenue guarantee per unit of available generation, offset by calculated operating profits per unit of deemed output. This is an important point for understanding the drivers of the GA: it is now influenced not only by production levels but by changes in generating *capacity* within different generator classes, offset by revenues earned within those classes. When spot prices are low relative to the cost of gas, such that the generator does not earn enough revenue from power sales to meet its revenue guarantee, the OPA pays the generator to make up the difference and passes that cost

on to the GA. The effect of this payment structure is that when the market price of electricity is low, the unit value of the GA will be higher, and when market prices are high, the GA will be lower.

The cost of conservation and demand management programs included in the GA are fixed and are unaffected by market factors. In addition, some of OPG's development projects (e.g., Hydro-electric Supply Agreements such as Lower Mattagami, biomass, and Lennox) allow for development costs to be paid up front by the OPA and therefore passed through to the GA, but are not generation-related.

Our review of the GA is hampered somewhat by the fact that several elements of the GA are not publicly documented. Examples include the quantity and price of historic or recontracted Non-Utility Generation contracts, the quantity and price of curtailed nuclear and renewable energy, the quantities and price of power subject to the Hydroelectric Contract Initiative, and the price paid to OPG for power from assets covered under the Hydro-electric Supply Agreements.

Box 1: Legal definition of the Global Adjustment

Source: O. Reg. 430/10, s. 1

For the purposes of this Regulation, the global adjustment for a month is the amount calculated by the IESO using the formula,

$$(A - B) + (C - D) + (E - F) + G + H$$

in which,

"A" is the total amount payable by the IESO under section 78.1 of the Ontario Energy Board Act, 1998 to generators who are prescribed under that Act for the purposes of that section, or to the OPA on behalf of those generators, with respect to output for the previous month from units at generation facilities that are prescribed under that Act for the purposes of that section,

"B" is the total amount that, but for section 78.1 of the Ontario Energy Board Act, 1998, would be payable by the IESO under the market rules to generators referred to in "A", or to the OPA on behalf of those generators, with respect to the output referred to in "A",

"C" is the amount payable by the IESO to the Financial Corporation under section 78.2 of the Ontario Energy Board Act, 1998 for the previous month, less amounts payable by licensed distributors with respect to output for the previous month from generation facilities that are prescribed under that Act for the purposes of that section,

"D" is the amount that, but for section 78.2 of the Ontario Energy Board Act, 1998, would be payable by the IESO under the market rules for the previous month with respect to output generated at, and ancillary services provided at, generation facilities that are prescribed under that Act for the purpose of that section and for which the Financial Corporation is the metered market participant,

"E" is the amount payable by the IESO to the OPA under section 78.3 of the Ontario Energy Board Act, 1998 for the previous month, less amounts payable by licensed distributors to the OPA for the previous month in respect of procurement contracts referred to in that section,

"F" is the amount that, but for section 78.3 of the Ontario Energy Board Act, 1998, would be payable by the IESO to the OPA under the market rules for the previous month with respect to output and ancillary services in respect of which the OPA has entered into procurement contracts referred to in that section and that are generated or provided at generation facilities for which the OPA is the metered market participant,

"G" is the amount payable by the IESO to the OPA under section 78.4 of the Ontario Energy Board Act, 1998 for the previous month, and

"H" is, if the month commences on or after January 1, 2011, the sum of all amounts approved by the Board under section 78.5 of the Ontario Energy Board Act, 1998 that are payable by the IESO to distributors or the OPA for the month.

3. Econometric modeling of the GA

3.1 Data sources and methods

We now turn to an econometric analysis of factors driving the rise in the GA after 2005. Guided by the structure of the policy, we explain the level of the GA in a month using the following variables.

Generator outputs in the previous month:
◆ Total wind generation;
◆ Total natural gas plus oil generation;
◆ Total solar generation;
◆ Total nuclear generation;
◆ Total hydro generation;
◆ Total coal generation.

Capacity variables as of the end of the previous month:
◆ Total installed hydro capacity;
◆ Total installed natural gas plus oil capacity.

Other variables in the previous month:
◆ Exports;
◆ Imports;
◆ Monthly dummy variables.

Variable in the same month:
◆ The change in the price of natural gas over the preceding month.

Because the HOEP interacts with both the dependent variable (GA) and the explanatory variables, it may introduce a problem of endogeneity bias.[7] To avoid this we used the inflation-adjusted price of natural gas instead,

---

7. Endogeneity bias refers to a reverse-causality problem in which the explanatory variable is a function of the dependent variable. It can severely bias the coefficient estimates in a regression model.

which strongly influences the HOEP (correlation = 0.86) but is largely determined by influences outside the country. However this variable appears to have a unit root, so we use it in first difference form.[8]

We limit the capacity variables to hydro and gas, because these are the only ones for which marginal additions have been accompanied by formal revenue guarantees. Below, however, we will explain the evidence that wind power acts in the GA system as if it were a capacity-contracted variable.

Exports potentially affect the GA because utilities outside the province that buy power only pay the HOEP. This can have several indirect effects. First, increasing exports in a month may drive up the HOEP, causing the GA to go down. But at the same time, by increasing the output of generators subject to GA guarantees, but selling to customers who only pay the HOEP, exports exert upward pressure on the GA. Imports matter since, in principle, they exert downward pressure on the HOEP (which would cause the GA to rise), and they limit the amount of power generation needed in the province, thus reducing the GA. So in both cases there are potentially positive and negative influences, but the regression results will show which ones dominate.

The variables, units, and sources are shown in **table 1**, and summary statistics are shown in **table 2**.

---

8. A unit root means the variable follows a random walk, or more formally, is nonstationary and has an undefined limiting variance. Use of such data in a regression causes a well-known problem of biased and spurious inferences.

Table 1

Data sources and units (at source)

Name	Units	Source
Global Adjustment	$/MWh	http://ieso.ca/Pages/Participate/Settlements/Global-Adjustment-Archive.aspx
Hourly Ontario Electricity Price	$/MWh	http://ieso.ca/imoweb/pubs/marketReports/download/HOEP-20140422.csv
Total Consumer Price Index	Unitless	http://www.quandl.com/BOC/CDA_CPI-Canada-CPI
Wind Power Capacity	MW	http://www.ieso.ca/imoweb/marketdata/windpower.asp
Hydro Capacity	MW	IESO Quarterly 18-Month Outlooks, Table 4.1, http://ieso-public.sharepoint.com/Pages/Participate/Reliability-Requirements/Forecasts-&-18-Month-Outlooks.aspx
Solar Capacity	MW	http://www.powerauthority.on.ca/quarterly-progress-reports-electricity-supply
Wind Power Output	MWh	http://ieso.ca/imoweb/pubs/marketReports/download/ HourlyWindFarmGen_20140418.csv
Imports and Exports	TWh	http://ieso.ca/imoweb/pubs/marketReports/download/ HourlyImportExportSchedules-20140422.csv
Output by Fuel Type (Nuclear, Hydro, Coal, Gas+Oil)	TWh	Supplied to the authors by staff at ieso.ca, April 30 2014.
Gas+Oil Capacity	MW	http://www.ieso.ca/Pages/Participate/Reliability-Requirements/Forecasts-%26-18-Month-Outlooks.aspx
Price of Natural Gas	$	http://www.quandl.com/. We used the commodity price deflated by Total CPI.

Note: All analyses use variables expressed in monthly terms.

Exports, imports, and HOEP were all available on an hourly basis over the 2005–2013 span. Wind capacity and output data begin in January 2006 and were assumed to be zero prior to that. Hourly data were changed to monthly values by averaging. This means that an important aspect of the effects of wind on the Ontario electricity system will not be resolved, namely the hour-by-hour mismatch during the day as wind tends to become available in the evening and overnight when demand is bottoming out. When this puts the system into a surplus baseload situation, other generators will offer power at zero or negative HOEP rates to avoid shutting down, and this exacerbates revenue deficiencies for contracted entities. To the extent that these episodes occur more frequently in a month, they will be reflected in the average wind generation data and the GA rates for the subsequent month, so they will be captured in our data, but not with intraday resolution.

Table 2

Summary Statistics (data span: monthly from 2005 to 2013)

Variable name	Definition/Unit	Minimum	Maximum	Median	Mean	Variance
GA	Real[1] Monthly Avg Global Adjustment ($/MWh)	-24.60	78.55	25.91	24.38	569.17
HOEP	Real Monthly Avg Hourly Ontario Electricity Price ($/MWh)	14.45	106.06	39.80	42.88	348.80
windcap	Installed Wind Power Capacity (MW)	0.00	2,382.00	1,083.60	1,009.48	556,345.90
wind	Monthly average of hourly outputs from wind farms (MW)	0.00	1,093.39	215.90	281.91	64,805.17
gocap	Installed Gas/Oil Power Capacity (MW)	4,976.00	9,987.00	7,582.00	7,427.33	4,591,301.00
gas-oil	Monthly average of hourly outputs from gas/oil plants (MW)	958.81	3,943.45	1,619.81	1,813.78	441,773.90
solar	Monthly average of hourly output from solar panels (MW)	0.00	412.56	0.00	28.01	5,428.12
nuclear	Monthly average of hourly outputs from nuclear plants (MW)	6,608.97	11,455.41	9,778.93	9,743.58	817,770.30
hydrocap	Installed hydro capacity (MW)	7,676.00	7,947.10	7,826.00	7,846.42	7,319.73
hydro	Monthly average of hourly outputs from hydro dams (MW)	2,805.73	5,554.13	4,125.97	4,045.48	308,991.80
coal	Monthly average of hourly outputs from coal plants (MW)	67.07	4,322.96	1,844.48	1,818.48	1,783,620.00
exports	Monthly average of hourly exports (MW)	627.68	3,512.39	1,605.01	1,669.49	292,053.70
imports	Monthly average of hourly imports (MW)	216.12	2,153.81	670.49	771.42	158,128.60
pgas	Monthly real price of natural gas ($ per thousand m3)	1.96	15.5	4.86	6.06	8.47

Note: (1) "Real" denotes inflation-adjusted.

Sources: See table 1.

The nuclear, hydroelectric, and solar capacity series are available quarterly and were interpolated to fill in monthly frequency. A solar output series was estimated using IESO data on monthly capacity utilization rates. We were supplied a combined gas-plus-oil power production series from the IESO, but since there was very little oil-fired power generation in Ontario over our sample period (2005 to 2013) we deemed the combination to be, primarily, a measure of the growth of gas-fired generation.[9]

The GA and the HOEP were both deflated using the all-items Consumer Price Index (CPI) rescaled so that the monthly series ends at 1.00, in other words so that the nominal and real values coincide at the end of the sample.

---

9. The Lennox plant is an oil/gas combination but it rarely runs and when it does it mostly uses gas.

3.2 Regression model

We use multiple regression to identify the principle drivers of the GA in Ontario. Application of the Breusch-Godfrey test indicated the presence of autocorrelation. So the estimates herein use OLS for the coefficient estimates and Newey-West standard errors applying automatic bandwidth selection to ensure robustness to autocorrelation. All calculations were done in R.[10]

The dependent variable is in $/MWh. The results of the GA model regression are shown in **table 3**. The monthly dummy variables are omitted but were included in the regression and their effects are included in all subsequent calculations. The model variables have a high amount of explanatory power. The model has an r^2 of 0.86, indicating that the explanatory variables account for 86 percent of the variance in the GA.

Table 3

**Results of first Global Adjustment regression model
(dependent variable: monthly GA)**

Variable	Coefficient	Standard Error	t-statistic
Intercept	-291.010	342.221	-0.850
wind	0.010	0.008	1.205
gas_oil	0.002	0.002	1.142
solar	0.031***	0.009	3.600
hydro	-0.001	0.002	-0.305
coal	-0.005***	0.001	-3.745
nuclear	-0.001	0.001	-0.513
hydrocap	0.038***	0.001	50.939
gascap	0.002***	0.000	8.714
exports	0.008***	0.001	8.166
imports	-0.010***	0.001	-9.080
Δpgas	-1.326***	0.327	-4.050

Notes: N = 108 observations. All explanatory variables except HOEP lagged one period. OLS R^2 = 0.87 and Adjusted R^2 = 0.83. *** denotes significant at <1%.

---

10. All variables were tested for unit roots using the Augmented Dickey-Fuller statistic test allowing for a trend and up to 3 lags. The unit root null rejected at 5% in all cases except for gas/oil capacity (p = ~0.06). The gocap variable has a strong step-like change around 2008–09, and structural breaks are known to reduce the power of standard unit root tests, so a Zivot-Andrews test was applied allowing for one structural break, which yielded a strong rejection.

3.3 Net effect of marginal wind output on the GA

The estimated coefficient (0.010) indicates that the GA goes up by $0.010 for every additional MWh of wind output averaged on a monthly basis.[11] The coefficient is not statistically significant, but we explain below why we believe it nevertheless should be treated as a valid effect. Taking the coefficient as estimated, the implied cost to the entire system can be computed as follows. Note that this calculation is based on adding an average of 1 MW of wind energy into the system 24 hours per day, 365 days per year.

Change in GA per additional MWh	$0.010
Times 2013 mean hourly electricity production	(17,941 MWh)
Times 24 hours, 365 days	(8,760)
Implied system cost	**$1,554,228**

By comparison, the direct FIT-related costs can be approximated as follows:[12]

Hourly FIT obligation less average selling price	$100.00
Times 24 hours, 365 days	(8,760)
Approximate direct cost	**$876,000**

The implied system cost is 77 percent higher than the direct costs. However, this is based on the assumption that wind operates on an energy-only basis. There is strong correlational evidence that the GA evolves as if it were based on wind capacity. **Figure 4** shows this in the form of a scatter plot of the GA against installed wind capacity.

---

11. For instance, if a wind farm increases its output by 1 MWh every single hour over a month, or if it increases its output by 2 MWh, 12 hours per day, every day in a month, etc.
12. In determining the price for the Regulated Price Plan for mid-2014, the OEB assumes that the direct payment weighted average for wind as of April 2014 will be 12.3 cents with the forecast HOEP at 2.6 cents/kWh. We have rounded the net expected cost to $100/MWh.

Figure 4

Global adjustment graphed against installed wind capacity
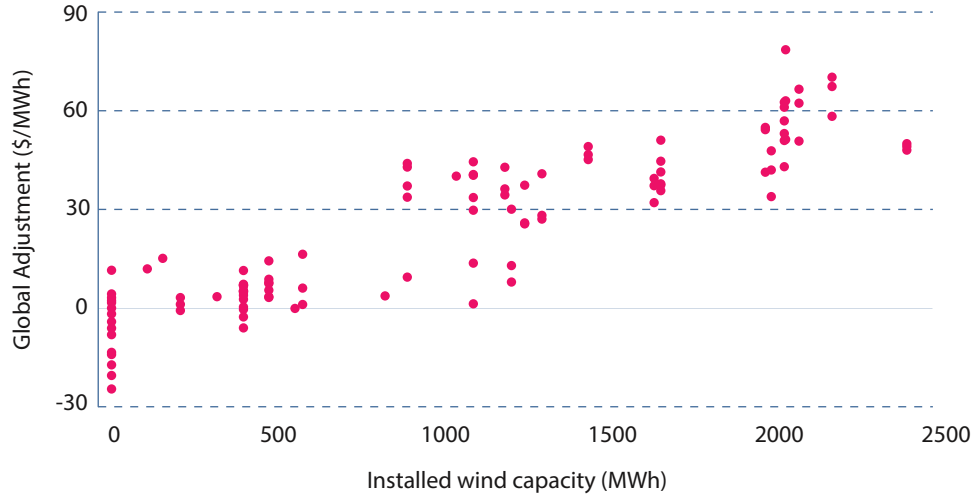
Source: See table 1.

If we include both wind capacity and wind output in the model, the results change in an interesting way, and show that wind capacity strongly influences the GA (**table 4**).

Table 4

Results of revised Global Adjustment regression model (dependent variable: monthly GA)

Variable	Coefficient	Standard Error	t-statistic
Intercept	-97.659	395.055	-0.247
wind	-0.001	0.007	-0.171
gas_oil	0.002	0.002	1.263
solar	0.016	0.013	1.210
hydro	-0.001	0.003	-0.213
coal	-0.005***	0.002	-2.842
nuclear	0.000	0.001	-0.311
hydrocap	0.015***	0.001	24.997
gascap	-0.002**	0.001	-2.079
windcap	0.021***	0.001	15.669
exports	0.005***	0.001	4.897
imports	-0.007***	0.002	-4.264
Δpgas	-1.241***	0.459	-2.704

Notes: $N = 108$ observations. All explanatory variables lagged one period.
OLS $R^2 = 0.89$ and Adjusted $R^2 = 0.86$.
** denotes significant at <5%; *** denotes significant at <1%.

Wind capacity has massive explanatory power, effectively dwarfing every other variable except hydro capacity. This strongly suggests that side-agreements and revenue guarantees, if not explicitly built into the FIT system, are implicitly present in other ways, and the GA has evolved in a manner highly consistent with a system in which wind farm operators are contracted for capacity rather than merely generation.

The results indicate that each additional 1 MW of wind capacity adds $0.021 to the GA. The implied overall system cost of 1 MW of new wind capacity can be computed as follows (again assuming that the additional capacity and output are present every hour all year):

Change in GA per additional MWh capacity	$0.021
Less change in GA induced by output	$0.001
Net (after rounding)	$0.021
Times 2013 mean hourly electricity production	(17,941 MWh)
Times 24 hours, 365 days	(8,760)
Implied system cost	**$3,157,334**

On this reckoning, the overall increase in the system cost is 3.6 times the direct cost associated with the FIT program. In other words, taking into account the changes in system parameters induced by the addition of wind capacity, the change in the GA, when applied to all electricity purchases, costs consumers three times the direct amount of the FIT payments themselves.

We also used the regression model to separate out the monthly effects due to wind expansion and those due to other factors. The portion due to wind energy was computed as

$$\text{GA}_{wind} = 0.021 \times windcap - 0.001 \times wind$$

This is shown in **figure 5** as the yellow line. In 2013, the wind component of GA averaged $14.60, or 26 percent of the mean total GA.[13] Figure 5 indicates, though, that the trajectory is clearly upward.

---

[13] The observed mean GA in 2013 was $59.04. The mean predicted GA from the regression model for 2013, which is the denominator for apportioning the contributions of the components in figure 5, was $56.58.

Figure 5

Comparison of Global Adjustment, predicted values from GA model, amount due to wind energy, amount due to solar energy, and amount due to other factors
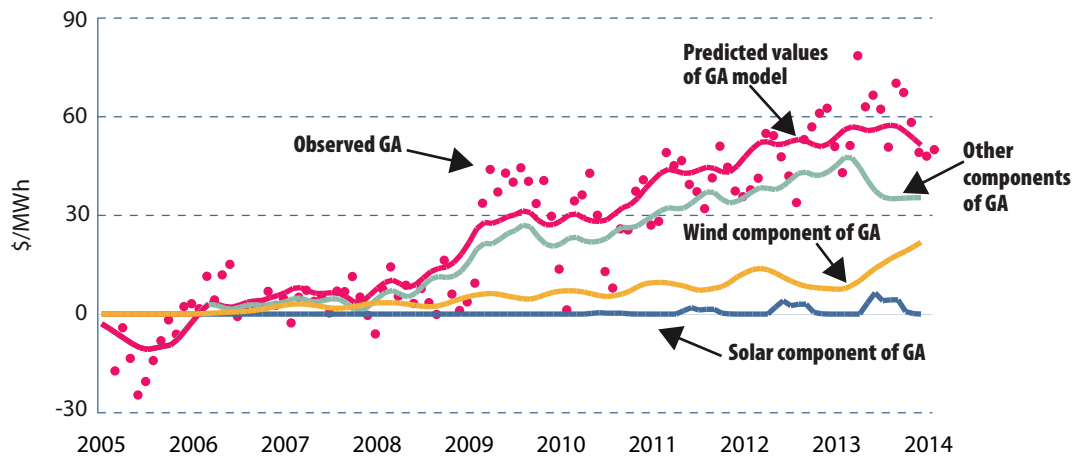
Note: Lines smoothed using lowess filter with bandwidth = 0.08.

Sources: Data from table 1; author calculations using regression model in table 4.

3.4 Net effect of marginal solar output on the GA

The direct FIT-related costs of solar can be approximated as follows. We first assume that the approximate weighted average of existing solar FIT contract rates less the HOEP is $460 per MWh.

Hourly FIT obligation less average selling price	$460.00
Times 24 hours, 365 days	(8,760)
Approximate direct cost of solar	**$4,029,600**

In the version of the model without wind capacity (table 3) the coefficient on solar output is positive ($0.031 per MWh) and significant. Solar is a very small fraction of total power generation in Ontario, but because of exceptionally high FIT rates, most of which fall in the range of $288–713/MWh, it is a costly electricity source, as indicated by the fact that the coefficient is an order of magnitude larger than those for the other output types. However, when we control for wind capacity (table 4), the solar coefficient falls in half to $0.016 per MWh and becomes insignificant. The implied system cost is as follows:

Change in GA per additional MWh	$0.016
Times 2013 mean hourly electricity production	(17,941 MWh)
Times 24 hours, 365 days	(8,760)
Implied system cost	**$2,457,788**

The implied system cost is only 61 percent of the direct costs. However, since the coefficient is small and insignificant, this result should be taken with caution. The GA contribution from solar can be computed as

$$\text{GA}_{solar} = 0.016 \times solar$$

This is shown in figure 5 as the blue line. In 2013, solar usage accounted for $1.95, or 3.5 percent of the mean total GA. Over the coming few years, solar capacity in Ontario will increase dramatically though, which will be major contributor to the expected increase in the GA.

The costs of wind and solar should be considered against the relatively minuscule amount of electricity they provide. The average commodity cost in 2013 (the sum of the HOEP and GA) was $83.58 per MWh, of which we estimate $18.55, or 22 percent, to be attributable to expenses related to solar and wind. In 2013, Ontario's total generation plus imports equalled 158.5 TWh. Of this, wind and solar contributed 5 TWh (3.2 percent) and 1 TWh (0.6 percent) respectively (Ontario Power Authority 2014c). Hence systems that contribute just under 4 percent of Ontario's power now account for 22 percent of the average commodity cost.

3.5 Net effect of new hydro capacity on the GA

The coefficient on hydro capacity (0.015) in table 4 is massively significant, indicating that the addition of 1 MW capacity would raise the GA by $0.011. The coefficient on hydro output is small and insignificant. The implied system cost of capacity expansion is as follows.

Change in GA per additional MWh capacity	$0.011
Less change in GA induced by output	$0.001
Times 2013 mean hourly electricity production	(17,941 MWh)
Times 24 hours, 365 days	(8,760)
Implied system cost	**$2,207,810**

Since there are no FIT's for hydro we do not compute a comparison to direct costs.

3.6 Other effects

Coal

The negative and marginally significant coefficient on coal (-$0.005) indicates that a 1 MWh increase in coal-fired generating output is associated with a 0.5 cent reduction in the GA, which translates into system-wide savings of $785,815 per year.

Exports and imports

These have significant and roughly opposite effects. Exports are associated with a GA increase of $0.005 per MWh, while imports are associated with a decrease of $0.007 per MWh. This suggests that the circumstances giving rise to exports are disadvantageous to consumers, whereas imports are helping to keep the GA lower. As discussed above, there are contrasting influences on both variables. The fact that exports have a significantly positive effect on the GA signals that reducing domestic electricity consumption amid a surplus of baseload power should not be a goal, if our objective is to lower the consumer cost. Conservation programs, expensive in and of themselves, thus make especially little sense when the province has a shortage of demand to begin with. When we are in a surplus baseload situation, rather than spending money on conservation, the province should encourage consumers find beneficial uses for electricity to increase demand so as to minimize the amount that has to be dumped at a loss.

Price of gas

The negative coefficient on the first difference of the price of gas indicates that in the period after an increase in the price of gas by $1 per thousand m^3, the GA falls by $1.24. As the HOEP gets pushed up, even non-gas generators benefit from the increased wholesale price, reducing the required GA-based compensation.

Using the regression model, we can allocate the mean GA in 2013 to the following:[14]

Wind energy	$14.60	26.1%
Solar energy	$1.95	3.5%
Other (including hydro)	$40.02	70.4%
TOTAL	**$56.58**	**100.0%**

This amount translates into just over $45 per month on an average residential power bill.

---

14. See footnote 11 on the slight difference between the mean observed and mean predicted GA values.

Our results contradict the claims of Chee-Aloy and Stevens (2014), who applied an accounting methodology and concluded that wind and solar energy each contributed only $5 to the GA, and that nuclear power was the largest driver of GA. Their analysis, upon which the activist group Environmental Defence relied in a prominent recent pamphlet campaign, failed to take into account the way that interactions among the different generating types exacerbate the GA burden. Nor did they indicate what percentage of the historical variance of the GA their method explains; the model we have presented herein explains close to 90 percent.

3.7 Discussion

The regression models yield a number of important insights into the determinants of electricity prices in Ontario.

1 Each additional 1 MW of new wind capacity adds about $0.02/MWh to the Global Adjustment, after taking into account the offsetting effect of revenues from wind production. The system-wide cost effect is about 3.6 times the direct FIT payment burden.

2 Each additional MW of new hydro over the past decade has added about $0.015/MWh to the GA. Factors behind the deteriorating performance of hydroelectric generation warrant further investigation.

3 Solar power generation has large marginal effects on the GA, which have been concealed by the relatively minimal amounts generated so far in the province. An increase of 1 MWh per hour, on average over a month, will cause the GA for that month to rise by about $0.016/MWh.

4 We estimate that solar and wind systems provide just under 4 percent of Ontario's power but account for about 20 percent of the average commodity cost. By comparison, the Ontario Energy Board (2013) forecast that, in 2014, solar and wind would produce 7 percent of total supply and account for about the same fraction of the average commodity cost.

5 Reductions in coal-fired power generation in Ontario were associated with statistically significant increases in the GA.

6 Imports can potentially reduce the GA, but exports occur under circumstances that increase it. Ontario is a large and growing power exporter. Encouraging greater domestic consumption at times of surplus baseload would reduce power costs in Ontario.

Nuclear refurbishment will be a major issue in the next decade, and if the province tries to make up for taking nuclear units offline by adding wind capacity or hydro, we expect to see even more substantial upward pressure on the Global Adjustment. Suppose the province attempts a swap of, say, 500 MW capacity from nuclear to wind. For reliability planning purposes, the IESO assumes that six-sevenths of installed wind capacity utilization will be unavailable during the summer peak season. Applying this ratio, to provide reliable year-round replacement of 500 MW of nuclear would require about 3500 MW of wind, potentially raising the GA by $3500 \times 0.021 = \$73.50$.

If instead the province opts for new hydro to replace a 500 MW nuclear unit, experience to date indicates that the effect on the GA would be to raise it by about $500 \times (0.015 - 0.001) = \$7.00$. This assumes that the new hydro is as cost-effective as recent hydro and can operate at 100 percent capacity whenever needed. More realistic assumptions would indicate worse consumer impacts.

Neither of these options is particularly attractive. In our recommendations at the end we will argue instead for a backup strategy centered on imported hydropower from Quebec and maintenance of 4 of the 12 units now closed at Lambton and Nanticoke.

Our detailed analysis of Ontario electricity market data shows that the current policy mix in Ontario guarantees a path towards increasing power prices, since the GA will continue to rise and the HOEP will not be able to fall enough to compensate. In fact, if the province carries through with its plans to expand solar and wind production even further, the trajectory of Ontario power prices will accelerate upwards even faster than its current trend.

There are a number of caveats to bear in mind when interpreting these results. Multiple regression models work by finding optimal patterns of correlation between explanatory variables and the dependent variable (in this case the GA). While it should accord with prior expectations of causality, such a model is not in itself proof of causality. Empirically, some of the key effects arise from system parameters that changed dramatically after 2009 when the Green Energy Act was introduced. In particular, solar was non-existent in Ontario prior to the FIT system and wind power was a tiny contributor that started providing a small amount of grid supply from commercial wind farms only in 2006. As a result, these effects are based on patterns near the end of the sample, which make them empirically less stable and powerful compared to patterns that persist across the entire data base. Finally, judgments about significance are based on efforts to control for potential specification problems in the model residuals, but alternative assumptions may yield different conclusions about which effects are significant or not. While we are confident of the model specification and interpretation, we remind readers of the inherent limitations of any econometric modeling exercise.

4. Cost reduction strategy

In light of the analyses so far, we now present some preliminary suggestions about what a strategy for reducing power prices should include. It should be emphasized that there is no magic bullet at this point that can guarantee lower Ontario electricity prices. For example, while the analysis clearly points to the need to stop adding renewables to the grid, and indicates that there would be cost savings from reducing the existing renewables capacity, it also indicates that such savings would at least partly be offset by an increase in the HOEP since wind operators would no longer be submitting bids at or near zero. However, this would represent increased reality in the pricing of Ontario electricity, which would contribute to increased efficiency over time.

4.1 No new hydro developments

The province has erred badly in adding high-cost hydroelectric units to its current generating mix. At a time when we currently have surplus baseload and no viable storage system, these units are not needed, and they appear to have had a large effect on the GA. Further investigation of the marginal cost of hydroelectric capacity additions and the impact of the Hydroelectric Contract Initiative appear warranted.

4.2 A moratorium on new wind and solar capacity

Another clear finding from the data analysis is that no reductions in Ontario power prices can occur without imposing a moratorium on new wind and solar contracts. We note that the strong positive effect on the GA of increasing wind capacity was an extremely robust result that emerged across numerous specification checks, and in every form and version of the model that we estimated.

Existing FIT contracts that have not yet reached what the OPA calls a Notice to Proceed (NTP) can be terminated. The FIT contracts stipulate that until the OPA issues NTP, and the supplier has provided to the OPA the incremental NTP security in accordance with Section 2.4 of the FIT contract, the OPA may terminate the FIT contract by notice to the Supplier.

4.3 Rescind existing long-term FIT contracts and subject renewables to market competition

Many European countries that had made costly commitments to renewable energy are winding back those commitments. Measures to mitigate costs include new taxes on generator profits, grid connection fees, and reduced rates for purchased power.[15]

Property tax changes and environmental penalties for killing birds have been suggested as strategies for reining in excessive renewable energy development.[16]

Trillium Power Wind Corporation ("Trillium"), a developer of off-shore wind power projects in Ontario, sued the Ontario government following a February 2011 decision to cancel planned FIT procurement of off-shore wind. Trillium initially claimed breach of contract, unjust enrichment, taking without compensation (which the appellant characterizes as expropriation), negligent misrepresentation and negligence, misfeasance in public office, and intentional infliction of economic harm. The Ontario Court of Appeal decision, issued November 12, 2013, narrowed potential grounds for the suit to proceed to misfeasance in public office alone, but recognized the broad authority of the government to change its policies without having to compensate affected businesses.[17]

Another approach to mitigating FIT costs that has been suggested is legislative change by the provincial government to roll back costs associated with renewables contracts that have already secured NTP and may even have been declared in service.[18] The general principal behind this option is that the government can write laws that, once passed in the legislature, nullify contracts the government itself signed previously.

Another approach proposed for mitigating excessive costs to ratepayers is to investigate cases where the business arrangements to procure high cost supply may have arisen in circumstances where competitive pressures were diminished and consumer interests may therefore not have been adequately protected. Of particular interest is the case of Samsung's wind and solar contracts, which were a sole-sourced procurement estimated to cost each Ontario resident $1,400 directly without considering indirect effects in its original form.[19] The counterargument to cancelling existing contracts through legislative measures is that it risks turning off future investors in the same types of projects. But when the contracts were so badly conceived and costly to

---

15. <http://opinion.financialpost.com/2014/03/18/governments-rip-up-renewable-contracts/>

16. <http://business.financialpost.com/2014/04/04/lawrence-solomon-reversing-renewables/>

17. <http://www.canlii.org/en/on/onca/doc/2013/2013onca683/2013onca683.html>

18. <http://business.financialpost.com/2014/05/14/killing-green-energy-contracts/>

19. <http://linkis.com/natpo.st/wxV7A>

taxpayers, creating disincentives against future such contracts is potentially a positive side-effect. Some of Samsung's wind developments are still pending and have been locally opposed, both factors that might be considered in efforts to mitigate future ratepayer exposure.[20]

A moratorium on new solar projects can be implemented immediately. As with wind procurement, legislation can be used to tear up solar FIT contracts, requiring solar providers thereafter to compete on the wholesale market.

4.4 Maintain 4 of 12 coal units in an operable state

While Ontario currently has an excess supply of baseload and intermittent generating capacity, as demonstrated by the poor performance of exports, it is low on variable power, for which coal and natural gas are the main options (biofuels being less abundant, much costlier, and often poorly suited for peaking service). In 2005, a cost-benefit analysis for the province (DSS/RWDI, 2005) showed that the installation of advanced air pollution control equipment on the 12 coal-fired units at Lambton and Nanticoke would bring their emissions of conventional air pollutants down by 75–95 percent, making them effectively as clean as natural gas, with the result that keeping them running with the pollution control retrofit completed would have nearly identical effects on Ontario air quality as closing them altogether. Of the 12 units, the pollution control systems had already been installed on units 3 and 4 at Lambton, and were partly installed on units 7 and 8 at Nanticoke, at the time the province announced its intention to phase out the coal plants altogether. We recommend that the retrofit be completed at Nanticoke 7 and 8, then the clean-burning units be maintained as part of Ontario's power mix.

The province has conducted a lengthy, misleading, and ill-advised public relations campaign to demonize coal use and to scare the public into thinking that air emissions from the Lambton and Nanticoke generating plants have large effects on Ontario air quality and threaten public health. For reasons spelled out in previous reports (McKitrick et al., 2005; McKitrick, 2013), we consider these claims groundless, contrary to evidence and common sense, and apparently politically motivated. Of particular importance, the government often points to the 2005 DSS/RWDI study as the basis for its position, but the numbers in that report instead showed that, with the pollution control retrofit in place, the coal plants would provide very clean generating options with minuscule impacts on Ontario air quality. The partial retrofit of Nanticoke 7 and 8 could be finished at a relatively low cost, allowing the province to keep 1000 MW of power generation online. Since coal is an abundant,

---

20. <http://www.windconcernsontario.ca/samsung-sweetens-the-deal-in-southgate>

low-cost fuel, and the Lambton and Nanticoke plants are reliable and fully scalable, there are substantial benefits to this option. Making the case even stronger, the federal government has implemented rules on power plant construction that all but forbid development of new coal-fired units unless they implement carbon capture and storage, a costly and largely infeasible technology, particularly for Ontario sites. Yet as European governments (such as Germany) have discovered, circumstances may arise in which having coal capacity online is unavoidably necessary, even beneficial. Keeping Lambton and Nanticoke running is therefore an important insurance against future contingencies (such as an increase in the price of natural gas).

We note with approval a comment in the Ontario Energy Board Regulated Price Plan report (May 2014 to April 2015) to the effect that "OPG plans to preserve half of the (coal) units to allow for conversion to an alternate fuel if required" (p. 15).

4.5 Investigate Quebec imports to bridge nuclear refurbishment and avoid storage

Some advocates, academics, and at least one prominent newspaper columnist have promoted the concept of Ontario replacing some of its generation with imports from Quebec.[21]

Hydro Quebec has long been a major supplier of electricity to New Brunswick, New England, New York State, and the City of Cornwall in Eastern Ontario. Low power prices in the U.S. have cut into Hydro Quebec's profits. While there is an opportunity for Ontario to source more supply from Quebec, there are also challenges.

A contract for energy sales that requires a commitment of capacity over the long term is called a "firm" sale. Purchasing long-term firm energy from Hydro Quebec would require Hydro Quebec to be willing to commit facilities. Quebec's non-diversified production creates challenges in managing natural variability in water availability. Flexible electricity trading arrangements are key to Hydro Quebec's strategy for managing natural variations in water availability. While firm sales must be backed by long-term dependable assets, non-firm sales can be used to take advantage of temporary surpluses that might arise due to water availability. In the last 5 years, firm sales constituted only 7 to 13 percent of total Quebec exports.[22] The average revenue

---

21. <http://sei.info.yorku.ca/2014/05/sei-seminar-series-ontario-quebec-and-electricity-time-for-a-new-relationship/>; < http://www.theglobeandmail.com/globe-debate/article19011993.ece>

22. <http://www.hydroquebec.com/publications/en/annual_report/pdf/annual-report-2013.pdf> (p.99)

earned by Hydro Quebec from firm versus non-firm exports has varied from a low of 1.5 times to a high of 2.1 times, with firm rates ranging from $79–$98/MWh. This price is very attractive relative to wind and solar costs in Ontario, but may not be attractive relative to other market opportunities.

While Hydro Quebec has surplus energy, Hydro Quebec may not have surplus capacity. Declining industrial demand in Quebec and flat overall demand in many export markets served by HQ, combined with new supply from projects such as the Romaine River developments, the expansion of wind power, and forest biomass power have contributed to a surplus of generation expected to extend far into the future.[23] While total energy sales have remained relatively flat, peak demand in Quebec has continued to increase, with record demands in the winter of 2012/13 broken by a new record during the winter of 2013/14.[24]

One potential opportunity for Ontario and Quebec to find a mutually beneficial arrangement would be some type of medium term arrangement allowing Ontario to access Hydro Quebec's surplus energy for a defined period to bridge requirements during Ontario's next round of nuclear refurbishments. NB Power used a similar approach in procuring from Hydro Quebec replacement power for the Point Lepreau nuclear station when it was removed from service for refurbishment from 2008 to 2012.

Another potential opportunity might be to develop some type of commercial arrangement for capacity outside of the winter peak to allow Ontario to better manage the variability of intermittent generation without having to build costly energy storage devices, while at the same time allowing Hydro Quebec to meet its firm load requirements in winter.

Other neighbouring jurisdictions, such as New York and Michigan, also face surplus baseload conditions, so contracting for greater volumes of US imports may also assist in cost containment.

4.6 Subject nuclear refurbishment to a cost-benefit test

With regards to refurbishment of nuclear plants, this should only be undertaken if the project will pay for itself; and the risk of a cost overrun should be placed on the private sector.

23. <http://business.financialpost.com/2014/03/01/is-quebecs-electricity-business-model-broken/?__lsa=4575-c978>; <http://news.hydroquebec.com/en/press-releases/490/hydro-quebec-provides-details-about-la-presse-article-of-december-21/?fromSearch=1#.U5gPepRdVy8>
24. <http://www.montrealgazette.com/Demand+power+punches+through+record+Hydro+Qu%C3%A9bec+appeals+reduced+consumption/9414028/story.html>

4.7 Additional research questions

Subject to the availability of data, a number of topics might also be examined in the future using the same framework presented herein, including the following:

◆ The effect of variability of wind and wind power on the GA;

◆ Distinguishing hydro capacity effect on the GA based on vintage and location;

◆ The extent to which marginal effects of wind and hydro capacity expansion on the GA are due to a failure to integrate them into the supply mix in an efficient way, versus intrinsic inefficiencies that cannot be remedied.

References

Alberta Retail Market Review Committee (2012). *Power for the People.*

Chee-Aloy, Jason, and Wesley Stevens (2013). *Components of an Ontario Residential Electricity Bill.* Report to Environmental Defence. <http://environmentaldefence.ca/reports/power-advisory-report-components-ontario-residential-electricity-bill>

DSS Management Consultants Inc. [DSS/RWDI] (2005). *Cost-Benefit Analysis: Replacing Ontario's Coal-Fired Electricity Generation. Closing the Coal-Fired Power Plants.* Mimeo.

Hydro Quebec (2012). *Comparison of Electricity Prices in Major North American Cities.*

Independent Electricity System Operator (2014). *Methodology to Perform Long Term Assessments.* IESO. <http://www.ieso.ca/Documents/marketReports/Methodology_RTAA_2014feb.pdf>

McKitrick, Ross R. (2013). *Environmental and Economic Consequences of Ontario's Green Energy Act.* Fraser Institute.

McKitrick, Ross, Kenneth Green, and Joel Schwartz (2005). *Pain Without Gain: Shutting Down Coal-Fired Power Plants Would Hurt Ontario.* Fraser Institute.

Ontario Energy Board (2013). *RPP Rates Analysis Nov 2013 to Oct 2014.* <http://www.ontarioenergyboard.ca/OEB/_Documents/EB-2004-0205/RPP_Price_Report_Nov2013_20131017.pdf>

All websites retrievable as of October 1, 2014.

Ontario Power Authority [OPA] (2013). *Cost of Electricity Service 2013 Long Term Energy Plan.* <http://powerauthority.on.ca/sites/default/files/planning/LTEP-2013-Module-4-Cost.pdf>

Ontario Power Authority [OPA] (2014a). *Understanding the Global Adjustment.* <http://www.powerauthority.on.ca/about-us/electricity-pricing-ontario/understanding-electricity-system-costs/understanding-global-adjustment>

Ontario Power Authority [OPA] (2014b). *Summary of Assumptions.* <http://powerauthority.on.ca/sites/default/files/planning/LTEP-2013-Summary-of-Assumptions.pdf>

Ontario Power Authority [OPA] (2014c). *Generation and Conservation Tabulations.* <http://powerauthority.on.ca/sites/default/files/planning/LTEP-2013-Module-3-Supply-Demand-Balance.pdf>

Appendix 1
Methodology for figure 2

Historical sales volume data are from the IESO.[1] 2014–16 sales projections are from OPA (2014) background papers for the 2013 Long Term Energy Plan.[2] Revenue requirements for the overall power system for the years 2004–12 were obtained from the OPA's 2007 Long Term Energy Plan[3] and by Freedom of Information and Protection of Privacy Act application to the Ontario Power Authority.[4] The actual and forecast revenue requirements for the overall power system for the years 2013–16 were taken from OPA background papers for the 2013 Long Term Energy Plan.[5] Inflation adjustments apply the Bank of Canada CPI currency converter.

Table A1

Ontario's electricity revenue requirement history ($2012)

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Commodity ($B)	6.9	10.8	8.2	9.2	9.4	9.3	9.9	10.0	10.7	10.6	11.6	12.3	12.6
Conservation ($B)										0.4	0.5	0.4	0.3
DRC ($B)	1.1	1.1	1.0	1.0	1.0	1.0	1.0	1.0	1.0	0.9	0.9	0.9	0.8
T&D ($B)	4.4	4.4	4.4	4.4	4.4	4.3	4.3	4.5	5.0	4.9	5.0	5.1	5.2
Regulatory ($B)	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.1	0.8	0.8	0.8	0.8
total RR ($B)	13.39	17.2	14.6	15.6	15.8	15.6	16.2	16.8	17.8	17.6	18.7	19.4	19.8
demand (TWh)	153	157	151	152	148	149	142	141.5	141.3	141.7	141.0	141.0	140.4
Rate ($/MWh)	87.5	109.6	96.7	102.6	106.8	104.7	114.1	118.7	126.0	124.2	132.6	137.6	141.0

1. <http://www.ieso.ca/Pages/Power-Data/Demand.aspx>
2. <http://powerauthority.on.ca/sites/default/files/planning/LTEP-2013-Summary-of-Assumptions.pdf> (issued January 2014): Chart 2.
3. IPSP Ex. G2/1/1 Tables 10–12.
4. <http://www.tomadamsenergy.com/wp-content/uploads/2013/03/OPA-FOI-response-re.-RevReq-to-2015.pdf>
5. <http://powerauthority.on.ca/sites/default/files/planning/LTEP-2013-Module-4-Cost.pdf> (issued January 2014): Slide 47.

Appendix 2
Methodology for figure 3

The residential and commercial rate histories are drawn from the Ontario Power Authority (2014b).[6] The only adjustment was to remove the impact of the Ontario Clean Energy Benefit from the data.

Figure 3 also uses data from a recent industrial rate benchmarking study published by the Association of Major Power Consumers in Ontario (AMPCO).[7] AMPCO's study reports on industrial rates in New Brunswick, Ontario, Quebec, Manitoba, Alberta, and British Columbia. AMPCO's methodology calculates the delivered wholesale costs for a typical industrial power consumer, applying a common description of the user (i.e., same demand, energy, power factor) for all jurisdictions studied. The reported rates are all-inclusive, reflecting charges for energy priced at market rates, capacity, transmission, and uplifts. Excluded are distribution rates and taxes. AMPCO also excludes customer-specific government programs that might be available to some users in some jurisdictions, an Ontario example of which is a program called Demand Response 3. AMPCO's methodology also does not consider whether specific customers hedge their power costs through either physical self-production or financial instruments. In AMPCO's studies, Ontario rates reflect the HOEP applying the annual industrial load-weighted rate, both the wholesale market service charge and the congestion management settlement credits reflected at the arithmetic average amount, and the renewable generation connection monthly compensation settlement credit (which started in May 2010).

Statistics Canada reports on industrial rates for large industrial users. However, the data provided is only on the basis of provincial prices indexed to 2009 prices. These indexes are calculated using a survey of rates in cents/kWh but the underlying rate data, although it is collected from utilities, is not disclosed. StatsCan's confidentiality rules prohibit the release of the original price quotes. StatsCan's methodology for collecting industrial rate index

---

6. Table for Slide 48 of Demand Forecast, 2013 LTEP: Module 1, issued in January 2014.

7. <http://www.ampco.org/index.cfm?pagePath=Analysis/Benchmarking&id=36556>

data does not differentiate between transmission-connected and distribution-connected consumers. StatsCan also does not appear to specify a load factor. As a result, even if the raw prices were released, without more information on the methodology, the raw information would be difficult to interpret. For Ontario, the sample of establishments surveyed include municipalities with what StatsCan describes as "the larger revenues from electricity generation in 2009," which appears to refer to electricity sales rather than generation. The use of this methodology in Ontario would tend to overestimate the province-wide price due to the higher distribution rates of some of the largest urban distribution utilities. There appears to be an anomaly in Statistic Canada's report on Ontario power rates. Statistics Canada provides price indexes for customers above and below 5 MW. From January 2002 to February 2009, the rates for Ontario customers over 5 MW are shown as 26 percent higher than for under 5 MW. From March 2009 until the end of 2013, the above 5 MW average is 6 percent lower than the under 5 MW average. The lower rates for larger customers after 2009 appear consistent with other available pricing data. However, the higher rates reported by Statistics Canada from January 2002 through February 2009 for the largest customers does not appear to represent a general rate trend.

Inflation adjustments apply the Bank of Canada CPI currency converter.

About the authors

Ross McKitrick

Ross McKitrick is a Professor of Economics at the University of Guelph and Senior Fellow of the Fraser Institute. He specializes in environmental economics. He has published many studies on the economic analysis of pollution policy, economic growth and air pollution trends, climate policy options, the measurement of global warming, and statistical methods in paleoclimatology. His latest book is *Economic Analysis of Environmental Policy*, published by University of Toronto Press (Fall 2010). He has also published numerous invited book chapters, newspaper and magazine essays, and think-tank reports.

In 2003, his (coauthored) book, *Taken by Storm: The Troubled Science, Policy and Politics of Global Warming*, won the $10,000 Donner Prize for the best book on Canadian Public Policy.

Professor McKitrick has been cited in media around the world as an expert on the science and policy of global warming. He has made invited academic presentations in Canada, the United States, and Europe, and has testified before the US Congress and the Canadian Parliamentary Finance and Environment Committees. In 2006, he was one of 12 experts from around the world asked to brief a panel of the US National Academy of Sciences on paleoclimate reconstruction methodology.

Tom Adams

Tom Adams is an independent energy and environmental advisor and researcher focused on energy consumer concerns. He has worked for several environmental organizations and served on the Ontario Independent Electricity Market Operator Board of Directors and the Ontario Centre for Excellence for Energy Board of Management. He is a media commentator and guest newspaper columnist. He has published peer-reviewed papers in a range of fields. He has presented expert testimony before many legislative committees and regulatory tribunals in Canada.

Acknowledgments

Publishing information

Distribution

These publications are available from <http://www.fraserinstitute.org> in Portable Document Format (PDF) and can be read with Adobe Acrobat® or Adobe Reader®, versions 7 or later. Adobe Reader® XI, the most recent version, is available free of charge from Adobe Systems Inc. at <http://get.adobe. com/reader/>. Readers having trouble viewing or printing our PDF files using applications from other manufacturers (e.g., Apple's Preview) should use Reader® or Acrobat®.

Ordering publications

To order printed publications from the Fraser Institute, please contact the publications coordinator:

- e-mail: sales@fraserinstitute.org
- telephone: 604.688.0221 ext. 580 or, toll free, 1.800.665.3558 ext. 580
- fax: 604.688.8539.

Media

For media enquiries, please contact our Communications Department:

- 604.714.4582
- e-mail: communications@fraserinstitute.org.

Copyright

Date of issue

October 2014

ISBN

978-0-88975-324-2

Citation

McKitrick, Ross, and Tom Adams (2014). *What Goes Up: Ontario's Soaring Electricity Prices and How to Get Them Down.* Fraser Institute. <http://www. fraserinstitute.org>

Cover design

Bill Ray

Supporting the Fraser Institute

To learn how to support the Fraser Institute, please contact

- Development Department, Fraser Institute
  Fourth Floor, 1770 Burrard Street
  Vancouver, British Columbia, V6J 3G7 Canada

- telephone, toll-free: 1.800.665.3558 ext. 586

- e-mail: development@fraserinstitute.org

Purpose, funding, & independence

The Fraser Institute provides a useful public service. We report objective information about the economic and social effects of current public policies, and we offer evidence-based research and education about policy options that can improve the quality of life.

The Institute is a non-profit organization. Our activities are funded by charitable donations, unrestricted grants, ticket sales, and sponsorships from events, the licensing of products for public distribution, and the sale of publications.

All research is subject to rigorous review by external experts, and is conducted and published separately from the Institute's Board of Trustees and its donors.

The opinions expressed by the authors are those of the individuals themselves, and do not necessarily reflect those of the Institute, its Board of Trustees, its donors and supporters, or its staff. This publication in no way implies that the Fraser Institute, its trustees, or staff are in favour of, or oppose the passage of, any bill; or that they support or oppose any particular political party or candidate.

As a healthy part of public discussion among fellow citizens who desire to improve the lives of people through better public policy, the Institute welcomes evidence-focused scrutiny of the research we publish, including verification of data sources, replication of analytical methods, and intelligent debate about the practical effects of policy recommendations.

About the Fraser Institute

Our vision is a free and prosperous world where individuals benefit from greater choice, competitive markets, and personal responsibility. Our mission is to measure, study, and communicate the impact of competitive markets and government interventions on the welfare of individuals.

Founded in 1974, we are an independent Canadian research and educational organization with locations throughout North America and international partners in over 85 countries. Our work is financed by tax-deductible contributions from thousands of individuals, organizations, and foundations. In order to protect its independence, the Institute does not accept grants from government or contracts for research.

Nous envisageons un monde libre et prospère, où chaque personne bénéficie d'un plus grand choix, de marchés concurrentiels et de responsabilités individuelles. Notre mission consiste à mesurer, à étudier et à communiquer l'effet des marchés concurrentiels et des interventions gouvernementales sur le bien-être des individus.

Peer review—validating the accuracy of our research

The Fraser Institute maintains a rigorous peer review process for its research. New research, major research projects, and substantively modified research conducted by the Fraser Institute are reviewed by experts with a recognized expertise in the topic area being addressed. Whenever possible, external review is a blind process. Updates to previously reviewed research or new editions of previously reviewed research are not reviewed unless the update includes substantive or material changes in the methodology.

The review process is overseen by the directors of the Institute's research departments who are responsible for ensuring all research published by the Institute passes through the appropriate peer review. If a dispute about the recommendations of the reviewers should arise during the Institute's peer review process, the Institute has an Editorial Advisory Board, a panel of scholars from Canada, the United States, and Europe to whom it can turn for help in resolving the dispute.