Technological Change in Electric Power Supply Chain: Quantifying Economic Benefits of General Electric's GT11N2 M

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Abstract

This paper examines General Electric's new combined-cycle gas turbine GT11N2 M upgrade. The new technology provides operational flexibility and promises output and cost efficiencies. To investigate the benefits of this technology, we propose a power supply chain model and construct cost functions for generation and service and maintenance using actual market and firm level data. The upstream firm is General Electric (GE) who invests in GT11N2 generators. The investment results in innovation of GT11N2 M upgrade facilitating different operational modes and efficiencies. The downstream firm is TransAlta's Sarnia plant which utilizes this new technology to produce and sell electricity to residential, small business, industrial, and wholesale market customers in Ontario, Canada. We quantify equilibrium prices and outputs under various efficiency rates in costs of fuel, service, and maintenance. We find a large variation in electricity generation depending on which operational mode ("Maximum Continuous Load" or "Performance" or "Lifetime") of GT11N2 M is selected. Under a mixed usage of all modes, we expect 44% output expansion to the industrial customers and 0.2% sales increase in the Ontario wholesale electricity market. Under this mode, GE's price should go down by 0.4% due to fuel cost efficiency. If GE's cost was \$2.8 per MWh, GE should have asked Trans-Alta an average price of \$5.822 per MWh for service and maintenance prior to the new technology. With the new technology, GE should charge \$5.502 per MWh to Trans-Alta. While GE's sales to wholesale market are almost stable, the sales to industrial customers increase nonlinearly in downstream efficiency rates. This shows that the amount of greenhouse gas emissions will be largely impacted by the choice of operational mode and how long it is used.

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1 Introduction

In the era of energy revolution, countries have been shifting away from dirty generation resources toward cleaner energy in their electricity markets. In this regard, Ontario, Canada became the first North American government to eliminate coal-fired electricity generation and pave the way for greener electricity system.[1] The closure of coal-fired generation plants has lead to more natural gas-fired generators and renewables such as wind and solar. The shift from coal to green energy sources is an important structural change in the Ontario electricity generation portfolio. The province is ambitious to be a leading green energy provider and the entire country has committed to have 90% of electricity generation coming from non-emitting energy sources by 2030.[2]

After decommissioning of coal-fired plants, the share of natural gas-based electricity generation has been increased. This is due to mitigate intermittency issues of wind and solar electricity and fill in energy gap created by the absence of coal generators. Coincidentally, right after coal plant phase-out in the province, in 2014, General Electric (GE) purchased Alstom's power and grid businesses including 11N2 gas turbines, which are being produced by GE with the nameplate GT11N2 since then. The initiatives of upgrading 11N2 gas-fired generators started in 2004 and became operational in 2008. The goals of the new technology GT11N2 M upgrade are to increase power output, reduce costs of operations and management, and allow flexible operation modes. According to GE, these goals have been achieved as the new upgrade has been operational worldwide and provided competitive electricity costs.[3] In this research, we study this technology in a supply chain framework and quantify market outcomes with and without GT11N2 M.

The main research question is that what would be the economic benefits of GT11N2 M to consumers and firms? GE claims possible efficiency gains from the new technology which opens up the following question: Could we measure the net impact of product and cost efficiencies of GT11N2 M? How would efficiency rates affect prices, outputs, and emissions?

[1] https://www.ontario.ca/page/end-coal
[2] The source is cleanenergycanada.ca
[3] https://www.ge.com/power/services/gas-turbines/upgrades/gt11n2-m

To address these questions we propose a simple vertical relations (supply chain) framework between upstream firm GE and downstream firm TransAlta (TA). GE is the supplier of GT11N2 generators and provides total plant solutions to TA via gas turbine field services, turbine repairs and parts, and rotor life extensions.[4] This implies that GE impacts TA's electricity generation cost function. We in detail construct cost functions for power production and service and maintenance using actual market and firm level data. The upstream firm GE invests in GT11N2 generators. The investment results in invention of GT11N2 M upgrade which facilitates different operational modes and efficiencies. The downstream firm TransAlta's Sarnia (TA-Sarnia) plant utilizes the new technology to produce and sell electricity to residential, small business, industrial, and wholesale market customers in Ontario, Canada. We specify demand for electricity by these different customer segments. The cost and demand functions change for each time period. We use daily data because input prices (such as natural gas spot prices) are daily. We specifically focus on 2014 data because GE gained ownership and management of GT11N2 generators in 2014. Each firm is a profit maximizer: GT optimally chooses its service and maintenance price of GT11N2 M generators and TA optimally chooses its production quantities for three customer groups. We use Stackelberg equilibrium solution to characterize market outcomes.

The main novelty of this research is to examine GT11N2 generators and determine their impact on supply chain outcomes. To our knowledge, this research topic has not been studied before. Furthermore, we construct a detailed variable cost function for electricity production taking into account of costs of fuel, service and maintenance, emissions, and of generator characteristics including heat and (CO2, NOx) emissions rates. In determining electricity customers of TA-Sarnia plant, we examine characteristics of residential, industrial and wholesale market customers. We then formulate their demand for electricity produced by TA-Sarnia.

After we construct cost functions and obtain model parameters by using real data, we run the model for each and every day of 2014 to figure out the impact of GT11N2 M upgrade on prices and outputs.

First we consider two types of cost efficiencies of GT11N2 M: upstream service and maintenance cost efficiency experienced by GE and downstream fuel cost efficiency experienced by TransAlta. We perturb efficiency rates and report equilibrium upstream prices and downstream outputs. We find

[4] www.ge.com/power/services/gas-turbines

that GE's prices decrease in downstream efficiency rates at decreasing rates, while prices decrease linearly in upstream efficiency. Price volatility increases in efficiency rates. TA-Sarnia's sales to the Ontario wholesale market increase in fuel cost efficiency rates at increasing rates. Higher efficiency brings about more volatility in outputs. In some days (and hours), Trans-Alta does not sell electricity to the wholesale market but its outputs are positive in residential and business customer markets. This stems from low supply conditions at Trans-Alta combined with low prices in the wholesale market.

Second we assess GE's expected efficiency rates over three operating modes of GT11N2 M upgrade. Each operating mode is associated with a different performance rating. However, in reality, it is not known to us how long and how often these modes are used per hour/day. To quantify the benefits of having switchable operating modes, we consider four scenarios. The first scenario assumes that only MCL-mode (Maximum Continuous Load) is used at all times; the second scenario supposes that only P-mode (Performance) is utilized; the third scenario involves L-mode (Lifetime) only; the fourth scenario, which we coin "Mixed-mode", assumes that each mode is used at equal proportions for each and every day of 2014. In addition, we consider a benchmark case which supposes what if the new technology was not used at all. We find that TA-Sarnia's ouput to industrial and wholesale customers are the largest under MCL mode, which is the most efficient mode in short-term. This mode is also favorable to TA-Sarnia and consumer groups as GE's prices are lower. Under the mixed-mode, we expect 44% output expansion in the industrial customers market and 0.2% output increase in the wholesale market. GE's price should go down by 0.4% due to fuel cost efficiency under the mixed mode. Prior to the new technology, if GE's cost was $2.8 per MWh, then GE should have asked Trans-Alta an average price of $5.822 per MWh for service and maintenance. With the new technology, GE should charge Trans-Alta $5.502 per MWh. While outputs in wholesale market are almost stable, output variations in industrial customer market are nonlinear and significant. This shows that amount of greenhouse gas emissions will be largely impacted by operations mode and how long it is used.

The structure of the paper is as follows. Section 2 introduces a simple supply chain model and characterizes equilibrium outcomes. Section 3 explains how the theoretical model can be applied to an electric power supply chain along with the structures of the Ontario wholesale electricity market and energy firms GE and TransAlta in the jurisdiction. Section 4 provides details of data to be used for constructing cost functions and electricity demand by different customer groups. Section 5 quantifies the benefits of GT11N2 M upgrade under various cost and output efficiency rates. Section 6 briefly summarizes the paper with key findings.

2 Model

We propose a generic model of vertical relations which will be adopted to a power supply chain in the following section. A firm (supplier S) in upstream market provides an intermediate product (or critical component or part) to another firm (manufacturer M) in downstream, which produces a homogeneous final product and sells it to a variety of consumer groups.

There are three types of consumers. Type 1 (T1) consumers buy q_1 amount from the manufacturer at a contract price p_1, which is fixed for the duration of contract. Type 2 (T2) consumers are price responsive and their inverse demand is $p_2 = a - bq_2$. Type 3 (T3) consumers has a broader access to market and can buy the product from multiple producers in the wholesale market, in which the manufacturer is a competitive fringe. Specifically, the manufacturer can sell its production q_3 at the wholesale market price p_3, which is stochastic and changes over time t.

The upstream firm engages in research and development (R&D), which leads to technological change or process innovation in a new product design or product improvement/upgrade which results in cost efficiency. The cost of producing intermediate good before R&D is $f_0 q_s$, where q_s is its output.

After R&D it is $f_1 q_s$, where $f_1 < f_0$ and $f = f_0 - f_1 > 0$ is the unit cost reduction as a result of R&D.

The intermediate product cost function $C_s(q_s) = f_0 q_s$ could have several interpretations. It could correspond to cost of producing a part or a component. Alternatively, it could represent variable cost of service and maintenance, if the product is service and maintenance. For example, in the industry application section below, f_0 will refer to operations and maintenance cost of producing a megawatt of electricity per hour from GE's GT11N2 natural gas-fired generator. GE provides this service at a price w to downstream electricity producer TransAlta-Sarnia.

R&D investment cost for the supplier is $D(I) = dI^2/2$,

where I is the level of investment carried out in order to achieve an innovation.

The supplier executing R&D and achieving efficient product improvement maximizes its profit function which is

$$\Pi_S = q_s(w - f_1) - D(I), \tag{1}$$

where w is a decision variable and represents price of intermediate product. Alternatively, w could refer to price of service and maintenance for intermediate product provided by the supplier.

The manufacturer buys the intermediate product/service from the supplier, produces a final product, and sells it to three consumer groups. It maximizes its profit function,

$$\Pi_M = q_1 p_1 + q_2 p_2(q_2) + q_3 p_3 - C(q_1, q_2, q_3), \tag{2}$$

where production cost $C(.)$ is convex and twice-continuously differentiable in output:

$$C(q_1, q_2, q_3) = w(q_1 + q_2 + q_3) + c_1(q_1^2 + q_2^2 + q_3^2). \tag{3}$$

In the application section, the first term will represent cost of service and maintenance to the manufacturer and the second term will involve costs, such as fuel and emission costs, associated with electricity generation. Notation-wise, c_1 represents cost coefficient after R&D and c_0 refers to cost coefficient before R&D such that $c_1 < c_0$ and $c = c_0 - c_1 > 0$ measures cost efficiency in downstream.

Given the input-output relations and the sequential nature of decision making between firms (the supplier choosing its price first and then the manufacturer choosing its quantities), we employ Stackelberg equilibrium approach. We solve the model and obtain the following.

Proposition 1: The Stackelberg equilibrium outcomes with R&D in the upstream are the following:

$$w = \frac{(p_1 + p_3)(b + c_1) + f_1(2b + 3c_1) + ac_1}{4b + 6c_1}$$

$$q_1 = \frac{p_1(3b + 5c_1) - p_3(b + c_1) - f_1(2b + 3c_1) - ac_1}{2c_1(4b + 6c_1)}$$

$$q_2 = \frac{a(4b + 5c_1) - (p_1 + p_3)(b + c_1) - f_1(2b + 3c_1)}{2(b + c_1)(4b + 6c_1)}$$

$$q_3 = \frac{p_3(3b + 5c_1) - p_1(b + c_1) - f_1(2b + 3c_1) - ac_1}{2c_1(4b + 6c_1)}$$

3 Application to Electric Power Sector

We will apply the vertical relations model developed above to firms operating in electric power sector in Ontario. Specifically, upstream firm General Electric (GE) invests in generator development, produces and sells GT11N2 type natural gas-fired generators to downstream firm TransAlta which uses these generators to produce and sell electricity to a variety of customer groups in Ontario.

We analyze how outputs and prices in the supply chain change with respect to technological change, called GT11N2 M upgrade. Before we execute our theoretical model to electric power firms, we will first explain the Ontario wholesale electricity market structure, expose the features of electricity and natural gas prices, and then offer details about the firms GE and TransAlta.

3.1 Ontario Electricity Market

Ontario is a manufacturing hub of Canada, and its power market is distinct from the neighboring jurisdictions (such as regulated power markets of Manitoba and Quebec, and restructured electricity markets of New York and Michigan) in many aspects such as its portfolio of production technologies, market clearing mechanism, price volatility (Genc and Aydemir, 2017). As such, the Ontario market price volatility is the highest in the North America (Genc et al. 2015). The Independent Electricity System Operator (IESO) is the clearing-house of wholesale electricity market and manages electricity flow in transmission network. The IESO runs a pool-type real-time auction for every 5 minutes and matches demand and supply to determine real-time prices. However, power transactions are based on hourly price called Ontario Hourly Energy Price (HOEP), which is the average of 5 minute-prices of auctions in an hour. Distribution companies and large industrial consumers are subjected to HOEP. There is no day-ahead forward market and the share of bilateral contracts is small due to the Ontario market design.

The IESO publishes actual hourly production and available capacity data for all generators, which are available at its website (www.ieso.ca). The size of power producers are asymmetric and there are a few strategic firms facing competitive fringe suppliers. The firms with large capacities include Ontario Power Generation Inc (OPG), Bruce Nuclear Inc (Bruce), and Brookfield Renewable Energy Inc (Brookfield). They are considered as dominant firms which can exercise market power. The rest of the firms including TransAlta are considered fringe suppliers (Genc and Reynolds, 2019).

To give a glimpse of Ontario wholesale prices, we plot daily prices in 2014 in Figure 1. Interestingly, the Ontario wholesale electricity market prices in the first quarter were highly volatile and expensive compared to prices in the final quarters. The polar vortex trapped cold air throughout the northeast resulted in cold temperatures and caused homeowners and businesses to ramp up their electricity demand. Natural gas reserves in storage depleted due to strong withdrawals which considerably increased natural gas prices. Gas inventories in the northeast hit the lowest levels in the past 5 years, so gas prices soared record highs. Therefore, higher gas prices caused higher electricity prices. In the figure, we also observe some negative electricity prices which stem from excess wind power injections causing more supply than demand.

<< Figure 1>>

As TransAlta-Sarnia runs gas-fired generators, natural gas prices are part of inputs costs for electricity generation. We use Henry Hub natural gas spot prices which are the benchmark for natural gas transactions in the North America including Ontario. Henry Hub spot prices are published daily. Figure 2 displays daily Henry Hub natural gas spot prices. Between January and March, residential and commercial demand for natural gas has increased due to low temperatures, as explained above. High demand combined with pipeline constraints and low gas reserves contributed to record-high prices. In summer, the need for air conditioning has gone down because of mild temperatures. This led to reduced demand for natural gas by the electricity producers. Therefore, natural gas storage increased from April through November. Consequently, natural gas prices fell during the rest of 2014.

<< Figure 2>>

3.2 The Manufacturer: TransAlta Sarnia

The electricity producer TransAlta (www.TransAlta.com) has the holdings of a variety of generators with different energy sources in the North America. In Ontario, TransAlta operates several wind farms and natural gas-fired plants with installed production capacity less than 1000 MW. In our study, we will focus on its largest natural gas-fired plant in Sarnia. Sarnia is the largest city on Lake Huron and in Lambton County. TransAlta's Sarnia Regional Cogeneration Plant has been producing electricity since 2003. The plant is located on a large land (268-acre) and this generation facility is registered as TA-Sarnia in the Independent Electricity System Operator's (IESO's) list of generators.

The Sarnia plant has three Alstom 11N2 gas turbines. General Electric (GE) acquired Alstom'ss power and grid businesses for 12.35 billion Euro in 2014 and 11N2 type generators are produced by GE with the nameplate GT11N2 since then. Each GT11N2 is capable of generating electricity between 102 and 118 MWh. In addition, TA-Sarnia operates two condensing steam turbines that can produce 120 MWh, and back-pressure steam turbines capable of generating 56 MWh. Its total production capacity in 2020 was 499 MW.[5]

The electricity produced by TA-Sarnia is sold to three demand segments: residential and small business, industrial, and wholesale market customers. Specifically, the Sarnia plant has long term contracts to supply steam and electricity to industrial customers such as ArLanxeo, Styrolution, Suncor Energy and Nova. The remainder of generation is sold to the Ontario wholesale electricity market through which residential and business customers are served via distribution companies. The industrial customers are charged "behind the fence" electricity prices which are private information and are only known by seller and buyers.

The Sarnia plant is highly efficient because it is a cogeneration facility producing electricity and steam simultaneously by burning natural gas. Steam is a byproduct as natural gas turbines generate electricity and heat. The heat produces steam in boilers. Steam can then be used for industrial processes or to generate additional electricity through a steam turbine. Specifically, the Sarnia plant's efficiency rates are 6707 kJ/kWh of heat rate, 0.07 g/MJ of NOx rate, and 0 g/MJ of SO2 rate, which are reported by Environment Canada's Module Unit List.[6]

The following table displays TA-Sarnia's hourly outputs and available production capacities in 2014. There was no plant outage and output variability was high with the minimum of 100 MWh and the maximum of 436 MWh. Distribution of outputs over hours shows that there were some output spikes in some hours and the likelihood of extreme outputs was significant. In particular, a positive skewness indicates that the distribution is asymmetric and there is higher probability of large outputs and lower probability of small outputs. The value of kurtosis is positive and larger than one, and indicates that distribution is leptokurtic (fat-tailed) and the likelihood of extreme outputs lying far away from the mean is significant. On the other hand, the distribution of available

[5]See https://transalta.com/facilities/plants-operation/sarnia/

[6]The Canadian Module Unit List shows the inventory of all currently operating electric generating units (EGUs) and planned-committed units and their relevant characteristics. The web-link is http://www.ec.gc.ca/air/default.asp?lang=En&n=D6C16D01-1.

Table 1: Hourly TA-Sarnia Output-Available Capacity in 2014

TA-Sarnia	mean	stdev	min	max	skew	kurtosis
output	187.19	73.62	100	436	1.32	1.03
avail_Capacity	436.29	54.12	225	510	-0.53	0.18

production capacities looks more like standard normal distribution and the variability of available production capacity is low, as expected.

3.3 The Supplier: General Electric

The purchase of Alstom's power assets including GT11N2 generators in 2014 was GE's largest-ever industrial acquisition.[7]

According to GE, the latest available technologies have been implemented to upgrade GT11N2 generators. The implementation of upgrades started in 2004 with the goals of increasing the engine power output, reducing the costs of operations and management, and allowing for flexible operation modes. All these goals aimed at ramping up efficiency. To meet these goals, the upgrade package (called GT11N2 M Upgrade) comprised of redesigning turbine blading, retrofitable for higher engine performance and longer lifetime. The upgrade ended in early 2008 with successful validation of implementation to a customer.[8] In addition to redesigning turbine blades, GT11N2 M upgrade has aimed to provide i) flexibility which translates into three switchable operating modes for maximum extended lifetime, extra power output and efficiency; ii) reduced maintenance costs through extended service intervals of up to 48,000 equivalent operating hours; iii) performance up to 14 MW more power output and up to 1.9% gas turbine efficiency. GE reports that this new upgrade has been operational worldwide and provided competitive electricity costs.[9] In the following section, we will tabulate the specifications of GT11N2 M upgrade.

4 Data and Implementation

We use hourly and daily market and plant level data for several years provided by the system operator IESO and others. The Ontario market and generator-level data have been been implemented by

[7]https://www.ge.com/news/press-releases/ge-completes-acquisition-alstom-power-and-grid-businesses

[8]https://www.powerengineeringint.com/world-regions/europe/how-a-continuous-improvement-cycle-benefits-turbine-customers/

[9]https://www.ge.com/power/services/gas-turbines/upgrades/gt11n2-m

previous research. For example, Genc (2016) measured wholesale price elasticity of demand using market power indices, Genc and Aydemir (2017) investigated the cross-border electricity trade and its impact on air emissions and welfare in Ontario. Genc and Reynolds (2019) examined the impact of renewable energy ownership on firm, market, and the environmental performance in Ontario. Billette and Pineau (2016) estimated market outcomes and welfare changes associated with electricity market integration under transmission constraints using Ontario and Quebec data.

We choose to focus on 2014 data because of the following reasons. First, as of 2014 all coal plants have been completely shut down and replaced by gas-fired generators and renewables. Shifting from coal to cleaner energy resources was an important structural change in Ontario which has opened a way to greener province in energy. Second, gas turbines ramped up production starting 2014 to mitigate intermittent wind and solar energy and fill in the absence of coal generators. The actual production data shows that the share of natural gas based electricity production is one of the highest in generation portfolio through 2014-2020 compared to previous years. Third, GE purchased Alstom's power and grid businesses including 11N2 gas turbines in 2014. Fourth, the upgrade package of GT11N2 M was already operational in 2014.

4.1 Demand by Consumer Types

Type 1 consumers

Type 1 (T1) consumers are comprised of households and small businesses including farms. They pay fixed prices, called time-of-use (TOU) rates, which are chosen by the energy regulator Ontario Energy Board (OEB) and have been implemented since 2005.[10] Table 2 shows these rates (which correspond to p_1 in the model) and their evolution over years. They are applied through periods of a day (on-peak, off-peak, mid-peak) that T1 consumers are subjected to. The rates change two times a year in summer and winter. In summer (May 1-October 31), off-peak time covers 7pm-7am, on-peak corresponds to 11am-5pm, and the rest is for mid-peak. In winter (Nov 1-April 30), off-peak time covers 7pm-7am, mid-peak corresponds to 11am-5pm, and the rest is for on-peak. In any year and season, all weekends and statutory holiday hours are treated off-peak period. In 2014 residential and small business customers paid 10.75 cents/kWh on average, as can be seen from Table 2.

An Ontarion household uses about 9,500 kWh of electricity per year which implies 1.08 kWh

[10] See https://www.oeb.ca/rates-and-your-bill/electricity-rates/historical-electricity-rates

Table 2: Type 1 Consumer Prices (cents/kWh)

Effective date	Off-peak price	Mid-peak price	On-peak price
Nov 1, 2013	7.2	10.9	12.9
May 1, 2014	7.5	11.2	13.5
Nov 1, 2014	7.7	11.4	14.0
May 1, 2015	8.0	12.2	16.1
Nov 1, 2015	8.3	12.8	17.5
May 1, 2016	8.7	13.2	18.0
Nov 1, 2016	8.7	13.2	18.0
May 1, 2017	7.7	11.3	15.7
Jul 1, 2017	6.5	9.5	13.2
May 1, 2018	6.5	9.4	13.2

Source: https://www.oeb.ca/rates-and-your-bill/electricity-rates/historical-electricity-rates

average consumption per hour in Ontario. In 2014, the average Canadian household used 11,135 kWh of electricity per year, corresponding to 1.27 kWh.[11]

We examine electricity consumption in the City of Sarnia, as TA-Sarnia provides electricity to businesses and households in Sarnia. It is the largest city on Lake Huron and is a part of Lambton County in southwestern Ontario with a population of 71,594, according to 2016 census.[12] The total population of Lambton County was 123,399 in 2016.[13] The total installed power generation capacity in Lambton County is 2,662 MW, including TA-Sarnia's capacity of 506 MW.[14] However, there are two utilities which provide power to Lampton County. The first one is BlueWater Distribution Company, owned and operated by TransAlta, serving Sarnia and adjacent small towns (Alvinston with population 2548, Oil Springs with population 648, Petrolia with population 5742, Point Edward with population 2037 and Warwick Township with population 3692). The second utility is HydroOne Networks Company serving the rest of Lambton County.

Given that BlueWater serves 86,261 residences and the average consumption figure in Ontario is 1.08 kWh, we assume that the total consumption of T1 consumers in Sarnia should be roughly around 95 MWh, which is below the average production quantity (187 MWh in 2014) of TA-Sarnia plant.

[11]https://energyrates.ca/residential-electricity-natural-gas/

[12]Note that population surveys are conducted in every 5 years, and 2016 survey is the closest measure of 2014 population.

[13]https://en.wikipedia.org/wiki/Sarnia

[14]TransAlta Energy Corporation – 506 MW Co-generation (natural gas) Greenfield Energy – 1,005 MW (natural gas) St. Clair Energy Centre – 577 MW (natural gas) Green Electron Power Project – 289 MW (natural gas – under construction) Photo-voltaic Solar Farms – 120 MW, and Wind – over 165 MW. This information is available at https://www.sarnialambton.on.ca/infrastructure/utilities

Type 2 consumers

Type 2 (T2) consumers correspond to industrial consumers of electricity served by TA-Sarnia. Their demand is price responsive as they can use alternative energy sources and their own back-up generators when needed, and have flexibility to shift production over periods. Their inverse demand is $p_2 = a - bq_2$, where the coefficients (a, b) have to be predicted. Sarnia is home to 62 industrial facilities and refineries. Their industrial customers are mainly petro-chemical companies and refineries including ArLanxeo, Styrolution, Shell Canada, Imperial Oil, Suncor Energy (Sunoco) and Nova, which are charged "behind the fence" (negotiated and confidential) electricity prices. [15] Because of the nature of confidentiality of industrial customer prices, we have "too little" information to estimate their demand coefficients. However, we offer the following procedure.

Given $p_2 = a - bq_2$, the demand function is $q_2 = a/b - p_2/b$. The maximum output at the Sarnia plant is 436 MWh and the maximum available production capacity is 510 MW in 2014. Because T1 customers consume about 95 MWh and the average Sarnia output is 187 MWh, we assume that the maximum quantity for T2 consumers should be around 187-95=92 MWh, which corresponds to an estimate of intercept a/b in demand equation. That is, 92 MWh is the maximum quantity demanded at price zero. Zero price is not anomaly in electricity markets and it can even drop below zero when production exceeds demand and network is constrained. This frequently happens during night times in the Ontario market.

We do not have data regarding how much electricity is actually sold to the industrial customers for each hour by TA-Sarnia. In fact, the actual price paid and quantity consumed by each industrial customer are confidential information. According to the U.S. Energy Information Administration Survey of 2010, the petroleum refining industry uses around one third of the electricity production.[16] Therefore, we assume that the average demand quantity $\overline{q_2}$ is equal to 62 MWh which is one third of the average production (187 MWh) in TA-Sarnia plant in 2014.

We assume that the average wholesale market price (the hourly Ontario energy price, HOEP) represents a proxy to the "behind the fence" pricing applied to industrial customers. This average hourly price in 2014 is 32.4 dollars per MWh. Given this assumption, the average price paid by industrial customers is equal to 32.4, denoted by $\overline{p_2}$.

[15] https://www.sarnialambton.on.ca/infrastructure/utilities
[16] https://www.eia.gov/totalenergy/data/monthly/pdf/flow/css_2019_energy.pdf

This leads to our estimates of $b = 1.08$ and $a = 99.36$. Consequently, the inverse demand estimate for T2 customers is $p_2 = 99.36 - 1.08q_2$, with demand $q_2 = 341.4 - 8.6p_2$. This implies that price elasticity of demand is equal to -0.16 at the average production and it is equal to -0.48 at the average consumption and price. The industrial consumers' demand is inelastic, but they are still responding to price increases at a low rate. Note that this elasticity figure is a point elasticity estimate for the yearly average. This estimate may refer to long-run elasticity and it is in line with the elasticity figures reported in the literature (see Genc, 2016). While short-run elasticities are estimated to be very close to zero, long-run elasticities can be close to -0.5 in general.

Type 3 consumers

When TransAlta's production in Sarnia exceeds total demands of T1 and T2 consumers, it can sell the remaining quantity to the Ontario wholesale electricity market (T3) through transmission lines. Because TransAlta is a small producer compared to others in the wholesale market, it is treated as a price-taker (see Genc and Aydemir, 2017).

Let q denote the total output of TA-Sarnia. Then, the output sold to wholesale customers (T3 type) is $q_3 = q - q_1 - q_2$, where q_1 is the quantity sold to T1 type consumers and q_2 is the output sold to T2 type consumers. Based on the average demand figures of T1 and T2 customers, the average TA-Sarnia output to wholesale market should be 187-95-62=30 MWh: the average production in 2014 minus the average T1 type consumption minus the average T2 type consumption. Therefore, we expect that 30 MWh should be the average quantity demanded by wholesale market customers ($\overline{q_3}$). Consequently, T3 customers' price, denoted by p_3, will be equal to the hourly Ontario energy price (HOEP): $p_3 = HOEP$.

To see the relationship between HOEP, load (Ontario market demand), and TA-Sarnia output, we run the following OLS regression using the actual hourly data.

$p_{3,t} = \alpha_0 + \alpha_1 L_t + \alpha_2 TAS_t + \epsilon_t,$

where $p_{3,t}$ corresponds to HOEP, L_t denotes load , TAS_t is the TA-Sarnia output, t refers to hour in 2014, and $t = 1, ..., 8760$. The OLS estimation yields,

$p_{3,t} = -131.681 + 0.00718L_t + 0.1839TAS_t$, where all coefficients are significant with p-value less than 0.01. The positive sign in front of TA-Sarnia output shows that TA-Sarnia has an incentive to sell into the wholesale market as HOEP prices keep rising. Alternatively, because TA-Sarnia is a high cost natural gas-fired plant, it will ask a high price for its output in the auction. The market price increases as it keeps producing more and more.

4.2 Electricity Cost Function before GT11N2 M

The upgrade of GT11N2 M is considered as a process innovation achieved by the supplier GE. As explained in the model section, TA-Sarnia's electricity production cost function is quadratic.

$C(q_1, q_2, q_3) = w(q_1 + q_2 + q_3) + c_0(q_1^2 + q_2^2 + q_3^2)$

holds before the upgrade and

$C(q_1, q_2, q_3) = w(q_1 + q_2 + q_3) + c_1(q_1^2 + q_2^2 + q_3^2)$

holds after the upgrade, where $c_1 = c_0 - c > 0$ and $c_0 > 0$ is the cost coefficient before the GT11N2 M upgrade and $c > 0$ is the cost reduction stemming from the upgrade. In electricity context, w may correspond to unit variable cost of maintenance service and/or parts, provided by the upstream generator maker GE to the generation firm TA-Sarnia. This is a valid assumption because GE not only sells GT11N2 generators to TA-Sarnia, but also provides generator service, maintenance, and parts.[17] The cost coefficient c_0 may reflect the input (natural gas) cost plus emissions costs which we will specify next in detail.

The marginal cost of electricity production is $MC(q) = w + 2c_0q$ for each unit of output q. The actual average output of TA-Sarnia is 187 MWh in 2014. When taking into account of maintenance, service, parts, fuel, and emissions costs, the marginal cost $MC(q = 187)$ at the average production will be a very large number. Therefore, to have a reasonable marginal cost figure representative of actual cost of generation, we need to rescale the above production cost function. The characteristics of the cost function assumed in the model section will be the same as the one reformulated below. With a slight modification, we rewrite it as

$C(q_1, q_2, q_3) = \lambda_0 w(q_1 + q_2 + q_3) + \ \lambda_1 c_0(q_1^2 + q_2^2 + q_3^2).$

The coefficients $\lambda_0$and λ_1 are scalers and may be chosen based on market conditions of a given power market. For the Ontario market and firms GE and TA-Sarnia, we assume that $\lambda_1 = 1/2K$. The number 2 in the denominator is to remove the effect of quadratic term when the derivative is taken. K corresponds to maximum available capacity at the Sarnia plant which can vary every hour depending on start-up, shut-down, ramp-up, ramp-down, maintenance schedules, etc. It is usually lower than the installed capacity of 510 MW and the average figure in 2014 was 436 MW,

[17] www.ge.com/power/services/gas-turbines

as reported in Table 1. As for λ_0, it may be chosen depending on actual costs and outputs figures. For $\lambda_0 = 10$, we run the model and obtain that the average equilibrium outputs are 65.05 and 27.6 MWh in T2 and T3 markets, respectively. For $\lambda_0 = 5$ we obtain that they are 62.18 and 30.95 MWh, respectively.

Observe that with $\lambda_0 = 5$ the equilibrium output in T3 market is in the ballpark of what we have estimated for average sales to be in T3 market (187-95-62=30 MWh: the average production in 2014 minus the average T1 type consumption minus the average T2 type consumption). Furthermore, a large change in this scaler does not lead to drastic changes in equilibrium outcomes. For other jurisdictions, an alternative way to find out this parameter is that λ_0 be heuristically optimized via simulations until outcomes get closer to actual ones, if actual data is available for T2 and T3 markets.

Given this reformulation, we compute that the marginal cost of electricity production at Sarnia will be $\overline{MC}(q = 187) = \$33.44/MWh$, when the average output ($\overline{q}$) is 187 MWh, the average available capacity ($\overline{K}$) is 436 MW, the average fuel and emissions cost ($\overline{c_0}$) is \$43/MWh, the maintenance service price ($\overline{w}$) is \$3/MWh, and λ_0 equals 5. This is a reasonable cost estimate for an efficient natural gas-fired generator in Ontario (see Genc and Aydemir, 2016, and Genc et al., 2007 for generation costs in Ontario).

On 10/1/2014, the TA-Sarnia output hit its lowest production of 100 MWh while its available capacity was 435 MW. Given this output-capacity pair, the marginal cost of production would be 24.88 \$/MWh. On the other hand, the maximum output of 436 MWh with available capacity of 510 was recorded on 1/22/2014. At this production-capacity level, the marginal cost of electricity would be 51.83 \$/MWh. Therefore, based on our methodology, the marginal cost of production falls into the interval of [\$24.88, \$51.83] per MWh with GT11N2 generators. The variation in marginal costs are normal as GT11N2 generators can be run at different modes with different efficiency rates which ultimately impact cost of generation significantly. We will explain these issues in Section 5.

Next we will calculate actual input costs. Specifically, we will compute c_0 from available data. Note that w representing maintenance service and/or parts price is a strategy and will be optimally chosen by the upstream generator maker GE. The marginal cost coefficient c_0 changes as time t changes and is formulated as follows.

$c_0(t) = c_{fuel}(t) + c_{SO_2} + c_{NO_x} + c_{CO_2}$,

Table 3: TA-Sarnia Site Generator Characteristics

Electric Generating Unit Name	Plant Type	Heat Rate (kJ/kWh)	NOx Rate (g/MJ)
Sarnia Regional: Generator 1	Cogen - C_Cycle	6,707	0.0688
Sarnia: Generator 1	Cogen - C_Cycle	9,187	0.0688
Sarnia: Generator 2	Cogen - C_Cycle	9,187	0.0688
Sarnia/Clearwater:Boiler1-Gen 1	Cogen - Gas	9,648	0.103
Sarnia/Clearwater:Boiler2-Gen 2	Cogen - Gas	9,648	0.103
Sarnia/Clearwater:Boiler3-Gen 3	Cogen - Gas	9,648	0.103
Sarnia/Clearwater:Boiler4-Gen 4	Cogen - Gas	9,648	0.103

Source: Canadian Module Unit List published by the Environment Canada

where the unit cost of fuel is calculated as

$c_{fuel}(t) = HR_{GT11N2} * p_{HenryHub}(t) * ConversionRate.$

The heat rate that varies over natural gas generators of TA-Sarnia is denoted by HR_{GT11N2}. [18]

The emissions costs are

$c_{SO_2} = HR_{GT11N2} * p_{SO_2} * SO_2 rate$

$c_{NO_x} = HR_{GT11N2} * p_{NO_x} * NO_x rate.$

$c_{CO_2} = HR_{GT11N2} * p_{CO_2} * CO_2 rate.$

Note that there was no carbon pricing in Canada up until 2018. A cap-and trade program was initiated in 2018 with a minimum price of \$10 per tonne of CO2. Therefore, carbon cost does not show up in our cost formulation because $p_{CO_2} = 0$ holds in 2014.

TransAlta's Sarnia plant consists of three Alstom gas turbines (called GT11N2 after acquisition) and three Nooter-Eriksen supplementary fired heat recovery steam generators (HRSGs), two Alstom and one Westinghouse steam turbines.[19] Accordingly, we form the following table to list the TA-Sarnia plant characteristics provided by the Environment Canada.

Given the heat rates in the table, we calculate average heat rate and assign it to HR_{GT11N2}. This is a reasonable assumption because i) not all generators are GT11N2 nameplate; ii) most importantly, we only observe the total electricity production at the Sarnia plant, but not the specific generation for each generator. Therefore, $HR_{GT11N2} = 9,096$ kJ/kWh is calculated.

The unit fuel cost is

[18] Alternatively see https://netl.doe.gov/sites/default/files/gas-turbine-handbook/1-1.pdf

[19] https://en.wikipedia.org/wiki/Sarnia_Regional_Cogeneration_Plant

$c_{fuel}(t) = HR_{GT11N2} * p_{HenryHub}(t) * ConversionRate.$

Natural gas is the main fuel for TA-Sarnia generators and we use daily Henry Hub natural gas spot prices to calculate fuel costs. In 2014, the average daily natural gas spot price was US $4.35 MMBtu, corresponding to CA $4.80 MMBtu at the average daily exchange rate of 1 CAD=0.90609 USD. The conversion rate in the cost formula reflects the relation between energy units such that 1 kJ = $0.947817 * 10^{-6}$ MMBtu.

Therefore, given the average heat rate, natural gas price, conversion rate, exchange rate, and 1000 kwh=1MWh we calculate that the average unit fuel cost in 2014 is

$c_{fuel,2014} = 9096kJ/kWh * CAD4.80/MMBtu * 0.947817 * 10^{-6}MMBtu = CAD41.38/MWh.$

The sulfurdioxide (SO2) emission cost is calculated as follows.

$c_{SO_2} = HR_{NG11N2} * p_{SO_2} * SO_2rate.$

Because SO_2 emission rate of TA-Sarnia generators are zero, reported by Environment Canada, the unit SO2 cost will be zero: $c_{SO_2} = 0$. Similarly, because $p_{CO_2} = 0$ in 2014 $c_{CO_2} = 0$ holds.

However, NOx emission cost is positive. Genc and Aydemir (2017) use the average NOx permit price of CA$2000 per MWh for the Ontario market. At the duration of their study period, emissions were not capped and traded in Ontario and fossil fuel-based generation firms purchased permits which intended to cover externality and social costs of electricity generation. Given this permit price, the average heat rate (of 9096) and average NOx rate (of 0.08834) in the above table, we calculate that the average cost of emitting NOx per MWh electricity generation would be CA$1.61/MWh in 2014. It is specifically calculated as follows.

$c_{NO_x} = HR_{GT11N2}*p_{NO_x}*NO_xrate = 9096kJ/kWh*\$2000/ton*0.08834g/MJ = \$1.61/MWh.$

Then our estimate for average marginal cost coefficient in 2014 is

$\overline{c_0} = c_{fuel} + c_{SO_2} + c_{NO_x} = 41.38 + 0 + 1.61 = \$42.99\,/MWh.$

For our model calibrations the parameter c_0 will vary daily as c_{fuel} changes daily.

4.3 Electricity Cost Function after GT11N2 M

The upgrade to new technology results in process innovation and cost reduction. Because c_1 is the cost coefficient after the product upgrade and c_0 is the cost coefficient before the upgrade, $c_1 < c_0$ holds and $c = c_0 - c_1 > 0$ is the generation cost efficiency rate stemming from R&D. Specifically, the total cost function with the new technology turns out to be

$$C(q_1, q_2, q_3) = \lambda_0 w(q_1 + q_2 + q_3) + \lambda_1 c_1(q_1^2 + q_2^2 + q_3^2).$$

In Section 5, we will examine how different cost efficiency rates impact market outcomes.

4.4 Maintenance and Service Cost Function

The upstream generator maker GE provides service and maintenance of GT11N2 generators. As explained in the model section, the cost of maintenance and service is linear which is $C_s(q_s) = f_0 q_s$, where $f_0 > 0$ is the marginal cost per MWh before the GT11N2 upgrade.

The service and maintenance cost function after the upgrade will be $C_s(q_s) = f_1 q_s$,

where $0 < f_1 < f_0$ and $f = f_0 - f_1 > 0$ is the service and maintenance cost reduction per unit stemming from R&D. According to California ISO (CAISO) 2018 report of "Variable Operations and Maintenance Cost", a default value for the variable operation and maintenance cost portion of natural gas-fired combined cycle and steam units is \$2.80/MWh. We assume the same cost figure for Ontario as labor and service costs are similar in both countries. Therefore, our estimate for the unit cost is $f_0 =$ \$2.80/MWh. Below we will explain how we will choose the efficiency rate f for service and maintenance cost in calibrations.

4.5 Efficiency Rates of GT11N2 M

GE has redesigned turbine blades and come up with state-of-the-art turbine aerodynamics and cooling with GT11N2 M upgrade. This new technology provides switchable operating modes for maximum extended lifetime, extra power output, and efficiency. It is also aimed to reduce variable service and maintenance costs, production costs, and emissions. GE states that this new upgrade has been contributing to competitive electricity costs. In the following table, we display the operating modes and efficiency rates.[20]

MCL (Maximum Continuous Load)-mode is optimized for peak demands, is associated with inspection (of hot gas path casing-the core) for intervals of 24,000 EOH (equivalent operations hours), and exhibits significantly increased combined-cycle power and efficiency. P (Performance)-mode is optimized for performance and lifetime, is associated with inspection intervals of 36,000 EOH, and showcases increased combined-cycle power and efficiency. L (Lifetime)-mode is optimized

[20] https://www.ge.com/power/services/gas-turbines/upgrades/gt11n2-m

Table 4: GT11N2 M Upgrade Modes and Efficiency

Benefits	MCL-Mode	P-Mode	L-Mode
Power output increase (MW)	14.3	10.2	4.2
Efficiency increase (add.) [%]	1.9	1.8	1.6
Interval extension [keOH]	0	12	24

Source: General Electric (www.ge.com/power)

for simple cycle applications which are suitable for low energy demand situations, corresponds to significantly extended inspection intervals of 48,000 EOH, and provides GT (gas turbine) power and efficiency. All these modes should lead to reduced CO2 emissions per MWh, and hence lower fuel costs, higher revenues, and reduced environmental impact.

Based on this table, it is clear that the new upgrade will reduce service and maintenance costs at TA-Sarnia plant, decrease cost of electricity generation, and improve air quality. However, neither GE nor Alstom does specifically say how much cost savings will materialize from fuel (represented by c_{fuel} in the model) and service and maintenance (represented by f in the model) per MWh electricity generation. In fact, the actual cost efficiency rates should depend on factors such as age of GT11N2 generator, mode, time, ramp-up and -down rates, and actual output quantity. Therefore, we will arbitrarily assume several efficiency rates in model calibrations to investigate how market outcomes will vary with respect to these rates. Specifically, we will assume the efficiency rates of $f = 0\%$, 5%, 10%, 15%, 20%, 25% and $c = 0\%$, 5%, 10%, 15%, 20%, 25%.

In Table 4 we display the model notation covering 19 parameters and 21 variables.

4.6 Objectives of TA-Sarnia and GE

In running the calibrations we have to consider production constraints and market conditions in Ontario in 2014. With the constraints, the objective functions are reformulated as follows. Before the upgrade, TA-Sarnia maximizes the following for each $t = 1, 2, ..., 365$

$max\Pi_{TAS,t}(.) = q_{1,t}p_{1,t} + q_{2,t}p_{2,t}(q_{2,t}) + q_{3,t}p_{3,t} - \lambda_0 w_t(q_{1,t} + q_{2,t} + q_{3,t}) - \lambda_{1,t}c_{0,t}(q_{1,t}^2 + q_{2,t}^2 + q_{3,t}^2)$

subject to

$q_{1,t} = 95,$

$0 \leq q_{2,t} \leq \overline{q}_{2,t},$

$0 \leq q_{3,t} \leq \overline{q}_{3,t},$

$\sum q_{1,t} + q_{2,t} + q_{3,t} = q_{TAS,t}.$

Table 5: Model Notation

Players	**Description**
GE	General Electric Inc; upstream firm
TA-Sarnia	TransAlta Sarnia Plant; downstream firm
T1, T2, T3	Consumer types
Parameters	
a	maximum price in $T2$ market
b	price sensitivity in $T2$ market
f_0	upstream marginal cost before R&D
f_1	upstream marginal cost after R&D
f	cost efficiency in upstream
d	investment cost parameter for GE
λ_0	a fixed generation cost coefficient
c	cost efficiency in downstream
c_{NOx}	unit cost of NOx emission
c_{SO2}	unit cost of SO2 emission
p_{SO_2}	price of SO2 permit per ton
p_{NO_x}	price of NOx permit per ton
HR_{GT11N2}	average heat rate of TA-Sarnia generators
SO_2rate	average SO2 rate of TA-Sarnia generators
NO_xrate	average NOx rate of TA-Sarnia generators
CO_2rate	average CO2 rate of TA-Sarnia generators
$ConversionRate$	1 kJ $= 0.947817 * 10^{-6}$ MMBtu
K	max production at TA-Sarnia
p_1	price charged to $T1$ customers
Index	
t	days of 2014; $t = 1, 2, ..., 365$
Variables	
q_1	quantity sold to $T1$ customers
q_2	quantity sold to $T2$ customers
q_3	quantity sold to $T3$ customers
q	total production in downstream
q_S	production quantity in upstream
w	service/parts price chosen by GE
I	investment made by GE
p_2	price charged to $T2$ customers
p_3	price charged to $T3$ customers
p_t	HOEP, hourly Ontario energy price
L_t	hourly load in Ontario
TAS_t	TransAlta-Sarnia hourly generation
c_{fuel}	unit fuel cost
λ_1	a variable generation cost coefficient
$p_{HenryHub}$	Henry Hub natural gas spot price
c_0	downstream cost coefficient before R&D
c_1	downstream cost coefficient after R&D
$D(I)$	upstream investment cost function
$C(.)$	downstream production cost function
Π_{GE}, Π_{TAS}	profits in upstream and downstream

Then GE maximizes its profit function for each day t of 2014,

$\Pi_{GE,t}(.) = (q_{1,t} + q_{2,t}(w_t) + q_{3,t}(w_t))(w_t - f_0) - D(I)$

Note that because T1 customer's price is fixed and their demand is stable, it is assumed that TA-Sarnia plant delivers 95 MWh load to the residential consumers for each and every day of 2014. So $q_{1,t} = 95$ holds. In addition, we match the actual production of TA-Sarnia ($q_{TAS,t}$) to consumer demands in which T1 consumers are served first, and then other consumer segments are served. In distributing the total output, we make sure that the outputs $q_{2,t}$ and $q_{3,t}$ are optimized and obey the non-negativity and maximum consumption constraints $\overline{q}_{2,t}$ and $\overline{q}_{3,t}$ in 2014.

5 Results

We calibrate the model to determine the impact of GT11N2 M upgrade on prices and outputs. Based on the findings in Section 4, we use the following parameter values for all calibrations: $a = 99.36$, $b = 1.08$, $\lambda_0 = 5$, and $f_0 = 2.8$.

5.1 The Impact of Upstream and Downstream Cost Efficiencies

We will perturb upstream cost efficiency rates at f = 0%, 5%, 10%, 15%, 20%, 25%, and downstream cost efficiency rates at c = 0%, 5%, 10%, 15%, 20%, 25%, which are hypothetical efficiency scenarios.

We run the model for each day of 2014 and report equilibrium price (w) for upstream firm GE with respect to cost efficiency rates. In Table 6, w-f0 represents a benchmark case in which there is no cost saving from service and maintenance (f0) and GE's price is w; w-f5 corresponds to GE's price when 5% service and maintenance (S&M) cost saving occurs; w-f10 refers to GE's price in the case of 10% efficiency in S&M; similarly others follow. Because $f_0 = 2.8$, 5% reduction corresponds to f5=2.66. Similarly, f10=2.52, f15=2.38, f20=2.24, and f25=2.1 hold at the assumed efficiency rates. The outcomes are reported in Table 6, where observe that the equilibrium S&M prices are highly volatile with minimum 1.184 and maximum 29.182 dollars per MWh. This price volatility stems from volatilities of downstream prices (in wholesale T3 market), costs of fuel (natural gas prices) and downstream available production capacities (of TA-Sarnia). In addition, S&M prices linearly

Table 6: GE's price with respect to different efficiency types and rates

	w-f0	w-f5	w -f10	w-f15	w-f20	w-f25
mean(w)	5.822	5.752	5.682	5.612	5.542	5.472
stdev(w)	3.463	3.463	3.463	3.463	3.463	3.463
min(w)	1.534	1.464	1.394	1.324	1.254	1.184
max(w)	29.182	29.112	29.042	28.972	28.902	28.832
	w-c0	w-c5	w-c10	w-c15	w-c20	w-c25
mean(w)	5.822	5.765	5.709	5.652	5.595	5.538
stdev(w)	3.463	3.468	3.474	3.479	3.485	3.491
min(w)	1.534	1.486	1.437	1.388	1.339	1.290
max(w)	29.182	29.165	29.149	29.133	29.118	29.103

decrease in S&M cost efficiency rate.

The second part of table presents GE's equilibrium prices with respect to TA-Sarnia's generation cost efficiencies from the new technology. Note that c0 (that is c_0) refers to unit generation cost due to fuel and emissions costs when there is no efficiency (this is the case before the implementation of GT11N2 M upgrade). This table shows GE's equilibrium price (w) distribution with respect to change in fuel and emissions cost efficiency rates. Specifically, w-c0 represents the benchmark case in which there is no fuel and emissions cost saving (c0) and GE's price is w; w-c5 corresponds GE's price when 5% fuel and emissions cost saving is realized; w-c10 refers GE's price when 10% efficiency in cost of fuel and emission happens; etc. Note that c is a variable and changes daily due to Henry Hub fuel prices. The average fuel and emissions cost ($\overline{c}$) is 42.98. With 5% efficiency rate, this input cost drops to 40.83 on average. That is, c5 refers to average cost of 40.83 dollars per MWh in case of 5% efficiency rate. Similarly, other cost reductions follow as the efficiency rates improve.

Observe that equilibrium prices are non-linear in fuel cost efficiency rates. Also, GE's price becomes more volatile as the efficiency rate improves. The gap between minimum and maximum prices is the largest when efficiency rate is 25%. Furthermore, for a given efficiency rate, GE's charges higher prices under fuel and emission cost efficiency than under service and maintenance cost efficiency. Therefore, for a fixed efficiency rate, we claim that the upstream efficiency (S&M cost savings), resulting in lower prices and higher outputs, provides more benefits to the consumers, but the downstream efficiency (fuel and emission cost savings), leading to higher prices and lower outputs, provides more benefits firms and the environment.

Table 7 presents TA-Sarnia's sales to the Ontario wholesale electricity market (T3) with respect to upstream and downstream efficiency rates.

Table 7: T3 market output with respect to different efficiency types and rates

	q3-f0	q3-f5	q3-f10	q3-f15	q3-f20	q3-f25
mean(q3)	31.248	31.402	31.555	31.708	31.861	32.014
stdev(q3)	6.939	6.947	6.955	6.963	6.971	6.979
min(q3)	0	0	0	0	0	0
max(q3)	41.070	41.226	41.383	41.540	41.697	41.854
	q3-c0	q3-c5	q3-c10	q3-c15	q3-c20	q3-c25
mean(q3)	31.248	31.441	31.635	31.830	32.027	32.225
stdev(q3)	6.939	6.965	6.992	7.019	7.046	7.074
min(q3)	0	0	0	0	0	0
max(q3)	41.070	41.245	41.422	41.599	41.778	41.956

In the first part of Table 7, we observe how equilibrium outputs in T3 market change with respect to upstream cost efficiency rates. In that q3-f0 represents the benchmark case in which there is no cost saving from service and maintenance (f0) and TA-Sarnia's output in T3 market is q3; q3-f5 corresponds to sales to T3 market in the case of 5% service and maintenance (S&M) cost saving; q3-f10 refers to output when 10% efficiency in S&M happens; etc. The equilibrium downstream outputs are volatile due to supply conditions (represented by variability in capacity, cost, and wholesale price), with the minimum of 0 and the maximum of 41.854 per MWh, and the volatility increases in upstream cost efficiency. TA-Sarnia increases its output to T3 market linearly as upstream cost efficiency rate goes up linearly.

The second part of Table 7 exhibits distribution of T3 market outputs with respect to downstream cost efficiency rates. The outputs increase in fuel cost efficiency rates at increasing rates. However, compared to prices, the volatility is much higher and the minimum takes 0 and the maximum gets 41.96. The main reason for this wide output interval stems from the significant changes in wholesale prices in the Ontario market.

In Table 8, we consider upstream and downstream cost efficiencies simultaneously. The first part of the table shows distribution of upstream prices as efficiency rates vary. Specifically, w-fc0% is the benchmark case when no cost efficiencies are experienced; w-fc5% refers to GE's price when 5% upstream cost efficiency (f=5%) and 5% downstream cost efficiency (c=5%) take place. The most extreme case is w-fc25% which reflects the lowest level of GE's prices when f=25% and c=25%. The prices decrease in efficiency rates at decreasing rates, while the price volatility expands.

The second part of Table 8 shows distribution of TA-Sarnia's outputs in T3 market with respect to efficiency rates. At the highest efficiency gain (f=25% and c=25%) TA can sell 1.75 MWh more

Table 8: Output and price distributions with both efficiency types

	w-fc0%	w-fc5%	w-fc10%	w-fc15%	w-fc20%	w-fc25%
mean(w)	5.822	5.695	5.569	5.442	5.315	5.188
stdev(w)	3.463	3.468	3.474	3.479	3.485	3.491
min(w)	1.534	1.416	1.297	1.178	1.059	0.940
max(w)	29.182	29.095	29.009	28.923	28.838	28.753
	q3-fc0%	q3-fc5%	q3-fc10%	q3-fc15%	q3-fc20%	q3-fc25%
mean(q3)	31.248	31.594	31.942	32.293	32.645	33.000
stdev(q3)	6.939	6.973	7.008	7.043	7.078	7.114
min(q3)	0	0	0	0	0	0
max(q3)	41.070	41.402	41.736	42.072	42.409	42.747

electricity to the Ontario wholesale market. On the other hand, at the lowest efficiency gain (f=5% and c=5%) TA can sell 0.35 MWh more electricity to the market. The outputs increase in efficiency rates at increasing rates. Again, as we have seen in all cases, high level of efficiency brings about more volatility in outputs. In some days (and hours), TA does not sell electricity to the wholesale market: the output is zero in T3 market, but it is positive in T1 and T2 markets. This stems from low supply conditions observed at TA plant combined with low prices in wholesale market.

5.2 Expected benefits of GT11N2 M

Table 4 presents GE's expected operating mode performance and efficiency rates from GT11N2 M natural-gas turbine. Each operating mode is associated with a different performance rating. However, in reality, we do not know how long and how often these modes are used per hour or per day. To quantify the benefits of having switchable operating modes, we consider four scenarios. The first scenario assumes that only MCL-mode (Maximum Continuous Load) is used at all times; the second scenario supposes that only P-mode (Performance) is utilized; the third scenario involves L-mode (Lifetime) only; the fourth scenario, which we coin it "Mixed-mode", assumes that each mode is used at equal proportions for each and every day of 2014. In addition, a benchmark case considers that the new technology has not been implemented yet or it has failed and the old generators are in place.

Based on Table 4, we assume that there is no service and maintenance cost efficiency in 2014 such that $f = 0$. One justification for this assumption is that the inspection intervals of these modes are 24,000 EOH (equivalent operations hours) for MCL-mode, 36,000 EOH for P-mode, and 48,000 EOH for L-mode. These operation hours for inspection together with the fact that there are 8760

Table 9: Expected Benefits of GT11N2 M Upgrade

	Without GT11N2 M	**With GT11N2 M**			
Output		MCL-Mode	P-Mode	L-Mode	Mixed-Mode
q_2	61.939	103.273	91.477	73.566	89.408
stdev(q_2)	(70.068)	(71.012)	(71.011)	(70.919)	(71.011)
q_3	31.248	31.321	31.317	31.310	31.316
stdev(q_3)	(6.939)	(6.949)	(6.948)	(6.947)	(6.948)
GE price(w)	5.822	5.800	5.801	5.804	5.802
stdev(w)	(3.463)	(3.465)	(3.465)	(3.465)	(3.465)

hours in 2014 should imply that service and maintenance cost during our study period should be zero.[21]

Next we will specify output efficiencies. TA-Sarnia has three GT11N2 generators. Given that its expected output increase in MCL mode is 14.3 per generator, we expect 42.4 MWh power increase in total. Similarly, the expected power increases in P and L modes are 30.6 and 12.6 MWh, respectively. For the mixed-mode, it should be 28.53 MWh, which is the average of these modes. These numbers represent output efficiency gains over operating modes.

For downstream cost efficiencies, we know from Table 4 that the fuel cost should go down 1.9%, 1.8%, 1.6%, and 1.77% for MCL, P, L, and Mixed modes, respectively.

Given these output and downstream cost efficiency rates, we run the model for all days of 2014. We report our findings in Table 9, where q_2 and q_3 represent average outputs in T2 and T3 markets. We also report output standard deviations and upstream GE's price and price standard deviations over the modes.

From TA-Sarnia's point of view, the most efficient generation mode in the short term is MCL. It can sell the highest output to both T2 and T3 markets. This mode is also preferred by the consumers as GE's average price is the lowest. Compared to the benchmark, which is the old technology, we expect that generation increase with the new technology in T2 market should be in the range of 19% (under L mode) to 66% (under MCL-mode). However, the more realistic figures should come from the Mixed-mode. Realistically, all modes should be used interchangeably during any given day because of electricity demand variability over the hours. Therefore, given the efficiency figures in the Mixed-mode, we expect 44% generation expansion in T2 market and 0.2% output increase

[21] On the other hand, it could be that the GT11N2 M generators were running for a long time, and they were scheduled for a service and maintenance in 2014. However, we would not know whether this happened or not.

in T3 market. Under this mode, GE's price should go down by 0.4% due to downstream fuel cost efficiency. Prior to the new technology, GE should ask Trans-Alta an average price of $5.822 per MWh for service and maintenance. With the new technology, under the mixed usage of all modes, GE should charge $5.502 per MWh to Trans-Alta. The outputs in T3 market are almost stable and GE's price changes over the modes are very small. However, the output variations in T2 market are nonlinear and significant. This shows that the amount of greenhouse gas emissions will be largely impacted by the mode and how long it has been operational.

6 Conclusions

In this paper we have examined technological change in a power supply chain involving innovation of GT11N2 M generators. We have investigated economics benefits of this new technology facilitating efficiency, operational flexibility, and durability. Specifically, we study upstream efficiency leading to cost reductions in service and maintenance experienced by General Electric and downstream efficiency resulting in cost reductions in electricity generation and output expansion experienced by TransAlta-Sarnia plant. We have quantified the impact of possible and reported efficiency rates on prices and consumptions over different customer segments.

To be able to measure efficiency gains in service, maintenance, and generation, we have constructed cost functions in detail using market and firm level data. We have identified power consumer groups and formulated their demands for electricity. We have examined GT11N2 M's three switchable operation modes for flexibility in power production, and compared it to old technology without having efficiency, performance, and flexibility features. Given these ingredients we have modeled vertical relations between General Electric and TransAlta-Sarnia, solved their strategic objective functions, and characterized equilibrium prices and outputs.

Qualitatively, we find that equilibrium prices and outputs are non-linear in downstream (fuel cost) efficiency rates, but linear in upstream (service and maintenance) cost efficiencies. The outputs increase in fuel cost efficiency rates at increasing rates, but higher efficiency brings about more volatility in outputs. GE's prices decrease, but become more volatile as the efficiency rates increase. For a given efficiency rate, GE's charges higher prices under fuel and emission cost efficiency rates than under service and maintenance cost efficiency rates. Consequently, for a fixed efficiency rate, we claim that the upstream efficiency provides more benefits to consumers, but the downstream efficiency provides more benefits firms and the environment.

Quantitatively, we have determined how efficiency types and rates affect prices and outputs. However, the actual impact of GT11N2 M's operational modes will depend on real-time demand conditions, supply and network constraints, as well as how long they will be used over time.

APPENDIX

Proof of Proposition 1: We solve the game backwards, starting with the manufacturer who maximizes its profit function to choose outputs for different consumers.

$$\Pi_M = q_1 p_1 + q_2 p_2(q_2) + q_3 p_3 - w(q_1 + q_2 + q_3) - c_1(q_1^2 + q_2^2 + q_3^2)$$

The first order necessary conditions (FOC) yield

$\dfrac{\partial \Pi_M}{\partial q_1} = p_1 - w - 2c_1 q_1 = 0$, and $\dfrac{\partial \Pi_M}{\partial q_2} = a - 2bq_2 - w - 2c_1 q_2 = 0$, and $\dfrac{\partial \Pi_M}{\partial q_3} = p_3 - w - 2c_1 q_3 = 0$, which imply

$q_1 = (p_1 - w)/2c_1$, and $q_2 = (a - w)/2(b + c_1)$ and $q_3 = (p_3 - w)/2c_1$.

Given these strategies, the supplier maximizes the following profit function to choose its price.

$\Pi_S = (q_1 + q_2 + q_3)(w - f_1) - dI^2/2$ subject to $I_{min} < I < I_{max}$. The constraint on the investment quantity is not critical, does not impact output choices, and implicitly implies a budget constraint on investment expenditures.

$\dfrac{\partial \Pi_S}{\partial w} = -\dfrac{2(b + c_1) + c_1}{2c_1(b + c_1)}(w - f_1) + \dfrac{(b + c_1)(p_1 + p_3 - 2w) + c_1(a - w)}{2c_1(b + c_1)} = 0$ which implies

$w = \dfrac{(p_1 + p_3)(b + c_1) + f_1\,(2b + 3c_1) + ac_1}{4b + 6c_1}$.

This can be inserted into the manufacturer's strategies to obtain outputs shown in the proposition. Furthermore, the signs of second order conditions are all negative, implying that the price and output strategies maximize firms' profits. □

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Figure 1: Daily Henry Hub Prices in 2014

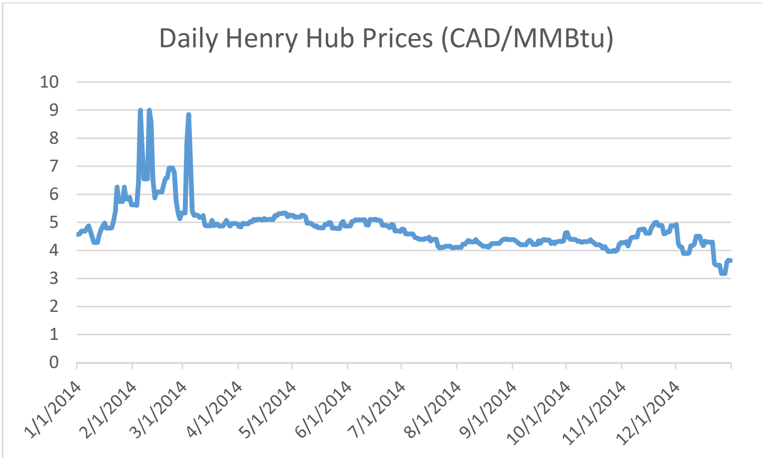

Figure 2: Daily HOEP Prices in 2014