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Ontario Retail Natural Gas and Electricity Markets

Prepared for:

Cassels Brock

September 2, 2010

Fred Hassan

Ontario Retail Gas and Electricity Markets

Table of Contents

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Ontario Retail Gas and Electricity Markets

Summary

Cassels Brock requested that e3xA prepare a paper that provides:

1. The historical background on Ontario natural gas and electricity deregulation and price formation.
2. Review the activities and choices of Ontario retail natural gas and electricity customers.

This paper provides an overview of:

1. The key milestones in deregulation of Ontario's natural gas and electricity markets,
2. A historical review of electricity and natural gas price components and their prices,
3. A description of the evolution of Retailer Codes of Conduct, and
4. Trends in retail energy contracting and an analysis of the choices made by retail natural gas and electricity customers.

This paper deals primarily with Ontario residential customers. The analysis of retail customers shows that retail residential customers attachment rates declined for gas when the Local Distribution Company's ("LDC") price fell dramatically and quickly. Consumers also tend to prefer Retailer fixed prices when prices are rising and when combined with increasing levels of price volatility. This observation is supported by research from other jurisdictions. In addition, Ontario electricity consumers tended to prefer LDC arrangements as the Provincial Benefit rose.

Natural Gas Market Evolution

The Canadian and Ontario natural gas markets evolved from regulated markets to unregulated markets. Figure 1 illustrates the trend in the price of natural gas and major milestones in the natural gas market evolution. Shortly after deregulation commenced the price of natural gas fell dramatically. This was primarily due to the huge inventory hangover from the National Energy Board's ("NEB") mandated 25 year reserve requirements that underpinned the approval and construction of long haul natural gas transportation systems. Once the NEB moved to an unregulated natural gas market TransCanada Pipelines Limited ("TransCanada") producers no longer were required to hold 25 years of reserve. As a consequence, producers were able to sell gas at market prices without the requirement of holding long term reserves to underpin the sale of natural gas. Some new longer term contracts initially did contain reserve requirements but this provision was gradually dropped from most short and intermediate term contracts.

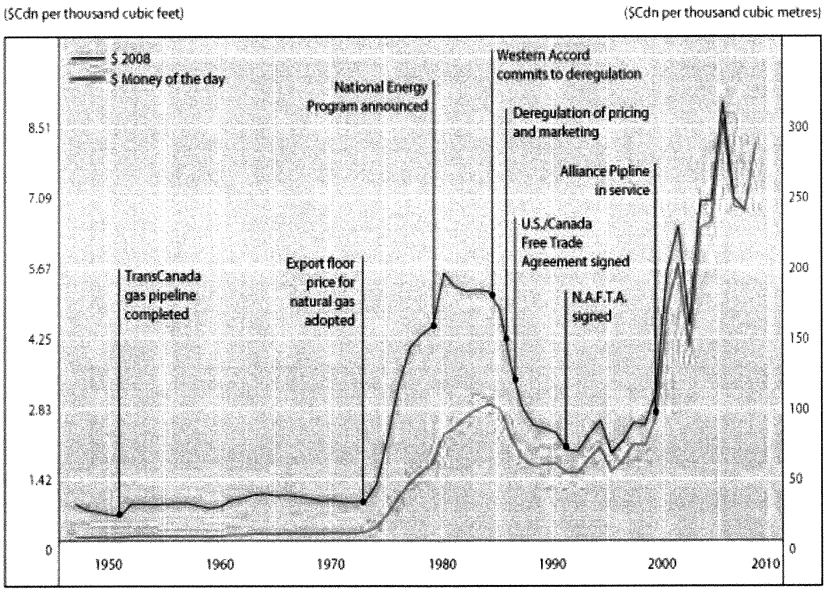


Figure 1: Historical Western Canadian gas prices with major market evolution milestones

Canadian exports to the United States flourished with significant new export pipeline expansion projects. As demand increased (with expansion of the use of natural gas for power generation) the 25 year reserve surplus was gradually bled off and prices began to rise in the late 1990's reaching record highs in 2007/8.

Natural Gas Price Components

In Ontario, the residential natural gas price is made up of the following components:

Gas Supply Commodity: This is priced on a fixed or variable basis and is a function of the customer's load shape, load factor, term of contract, size of load and credit quality, as well as, other terms and conditions in the supply arrangements. In Ontario, for residential customers under regulated LDC gas supply this price is set by regulation and varies over time. Variances in the commodity price compared to the LDC's forecasted price are collected in the LDCs' purchase gas variance account ("PGVA"). Today these variances are normally cleared on a quarterly basis as approved by the Ontario Energy Board ("OEB").

Residential customers who purchase their gas supply from Retailers have their commodity price determined by their agreement in their contract with the Retailer.

Transportation: The costs, both fixed and variable, to move the gas from its receipt point to the LDC's delivery point. This also includes the fuel gas required to move the gas along the transportation system to Ontario.

Distribution: This includes the ~~LDCs~~LDC's costs to provide daily balancing services, storage, inventory carrying costs, gas losses, barometric adjustments, as well as, the distribution costs to move the gas from the LDC's receipt point to the residential customers. It also includes meter reading, billing and bad debt costs.

The LDCs bill and collect for all customers including ~~Retail~~retail customers. For retail customers the Retailer's name is shown on the LDC's invoice to the customer. For residential customers the only part of the bill that is affected by purchases from Retailers is the commodity costs.

Ontario Natural Gas Direct Purchase

Ontario commenced natural gas direct purchase in the spring of 1987. This was made possible by the Federal Provincial Agreement on Natural Gas signed on October 31, 1985 (the "Halloween Agreement").

> "The Board (i.e. National Energy Board) implemented the MBP (Market Based Procedure) shortly after the Governments of Canada and the three gas producing provinces of British Columbia, Alberta and Saskatchewan signed an Agreement on Natural Gas Prices and Markets on 31 October 1985. This Agreement provided for a landmark change in the Canadian natural gas market by allowing gas buyers, for the first time, to directly contract for supplies with producers, marketers and other agents at freely negotiated prices. From 1975 to 1985, the price of natural gas sold in interprovincial trade in Canada had been regulated by joint agreement between the federal government and Alberta. Further, prior to the Agreement, gas buyers in nonproducing provinces could purchase their gas requirements only from a pipeline company at a "bundled" price which included the cost of gas and the cost of transportation."[1]

Because Ontario was not a party to the federal provincial agreement it was necessary for the Ontario natural gas LDCs to renegotiate and restructure their existing agreements with TransCanada. TransCanada was the gas supply aggregator for the western producers/suppliers and also was the "bundled" transporter of the gas supply to Ontario. Although the new agreements resulted in price reductions across the LDC supply portfolios, discounts for industrial and commercial customers varied by term, size and load factor. Because the LDC supply portfolios were an average price of all the supply in the LDC's portfolios, the LDC's prices

[1] Natural Gas Market Assessment, Canadian Natural Gas, Ten Years after Deregulation, National Energy Board, pg v, November 1996

initially remained higher than a customized large commercial industrial customers' new market price both under direct sales as well as under the LDC option. Initially producers streamed discounts to the large commercial industrial customers either directly or through the LDCs. Smaller customers obtained smaller reductions through the LDC's portfolio cost changes.

In July of 1987 the NEB approved a process of relieving the LDC shippers of demand charges when the capacity that they had under contract with TransCanada was unbundled and assigned to other shippers. This avoided a significant risk (what was referred to as "double demand" charges) and facilitated direct purchase.

Ontario receives the bulk of its gas supplies from Alberta and the United States through long distance transmission systems. A small amount of gas (about 10 Pj/year) is produced in Ontario. Prior to deregulation TransCanada provided the Ontario LDCs a bundled transportation and gas supply service under long term gas supply contracts. These contracts underpinned the building, operation and expansion of the TransCanada system. To allow for direct sales to proceed, under acceptable conditions, provisions had to be made to separate the gas supply arrangements from the transportation component. In addition, agreements had to be made to allow for a systematic reduction of the previous contracted TransCanada gas supply arrangements to allow for the flow of new gas supply from new suppliers to direct purchase customers. These arrangements were referred to as commercial operating demand ("COD") reductions. COD allowed for the reduction of the LDC's supply obligations. This was accomplished with a simultaneous assignment of the related TransCanada pipeline capacity to the direct purchasers. This ensured that the previous contract arrangements for the transportation capacity on TransCanada remained fully contracted. At that time, most direct sales were to large commercial industrial customers. In 1987 there was a large differential between the cost of gas embedded in the LDCs' long term gas supply and the new gas market supply price. The new gas supply price normally was a function of the size of the customer load, load shape, load factor, term of the contract, and credit quality. Large customers therefore generally had prices that were substantially lower than prices offered to smaller customers (see Figure 2).

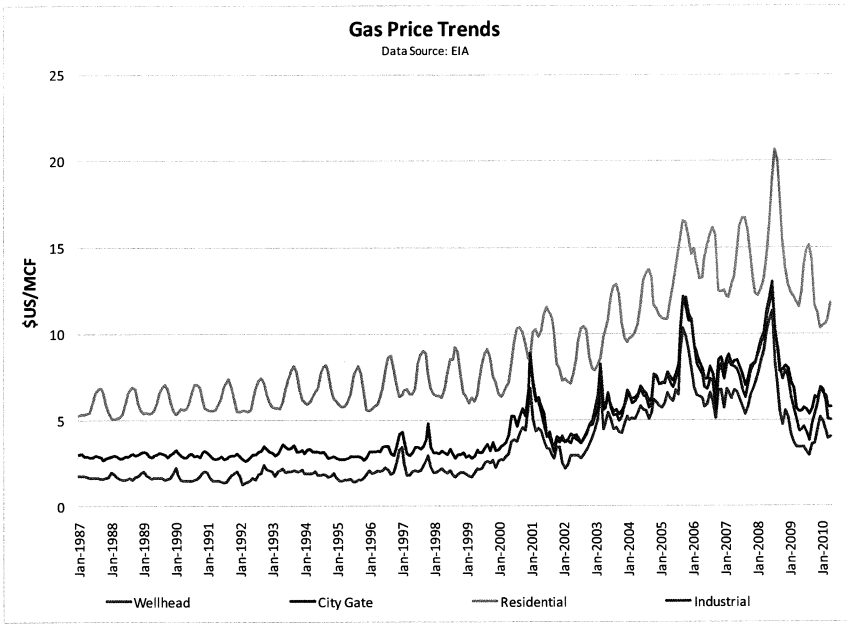


Figure 2: Gas price 1987-2010

Since the LDC contracts had an **average** price embedded in their portfolio the then prevailing direct price was substantially lower than the embedded LDC **average** cost of gas. This created a very large incentive for large commercial and industrial customers to purchase their gas supply directly from wholesalers. Within a very short period of time most large industrial and commercial customers purchased their gas directly from wholesalers. Gradually as the ~~LDCs'~~LDCs restructured their gas supply portfolios the LDCs' **average** cost also fell over time but **normally** remained above the prevailing spot market price. The LDC gas supply product was a fundamentally different product compared to the new market products. The new products had prices based on the product characteristics (i.e. spot daily price versus fixed annual term average portfolio price).

In the late 1980's and early 1990s Retailers started to aggregate residential and small commercial customers in Ontario. By aggregating a sufficient number of customers ~~retailers~~Retailers could contract for large enough blocks of gas to qualify for gas supply discounts and also meet the minimum contract requirements under transportation and distribution direct contract criteria. This allowed Retailers to offer fixed priced retail contracts

to individual residential customers at terms, conditions and prices that were generally competitive with the LDC **average** variable price regulated option.

Historically Ontario ~~LDC's~~LDCs set their embedded gas commodity prices based on a full cost of service Ontario Energy Board ("OEB") rate case. Under the old regulated price environment TransCanada would obtain NEB approval for cost of gas changes. These changes included the cost for gas supply, as well as, changes in the transportation and fuel component of TransCanada's rates. These cost changes were included in the bundled rate changes that were passed through to the LDCs once the NEB had approved the TransCanada proposal. These rate changes generally took place annually. Once the NEB approved the new TransCanada tariffs the Ontario LDCs would seek to recover these costs through either a main rate case or a cost of gas hearing and seek approval from the OEB to pass through these new costs.

Under the NEB's new market based unbundled approach the gas supply price and the transportation components were separated with the transportation component remaining regulated by the NEB. In the early period of deregulation the new gas supply arrangements were priced for 2-3 year price periods (some also had an annual price change provision in a multi year contract while later contract pricing became indexed to either an Alberta index or a NYMEX index). The new negotiated prices required that TransCanada seek approval from their producer group. This was done by ballot to the approximate 750 producers. As a consequence these producers and most large market participants knew the price and terms underpinning the 2-3 year price period that was embedded in the LDCs' contracts. Some of the TransCanada producers also began selling uncontracted (to the producer pool) gas directly to wholesalers and Retailers as well as to large industrial customers.

Once direct purchase displacement under the revised TransCanada contracts cut into the existing LDC supply portfolios, suppliers became reluctant to enter into new arrangements that allowed for the operating demand reductions to facilitate future direct purchase. As a consequence buyers who requested COD type flexibility in their contracts paid a price premium for this added flexibility. This added feature while providing flexibility tended to create a higher average cost of gas than the prevailing market price for new term gas supplies that did not have this feature. The LDCs, therefore, started to move towards shorter term portfolios with higher levels of spot gas in their portfolios. This allowed LDCs to accommodate future direct purchase arrangements while minimizing additional premiums in their supply arrangements. Nevertheless, because the LDCs continued to have an obligation to serve customers the LDCs had to ensure that their supply portfolios could adequately meet their customers' needs while ensuring supply acquisition could pass the OEB's cost and planning reviews. This allowed for direct sales to proceed without having to displace (CODing) existing term gas supply arrangements. This combined with a general trend in North America to shorter term gas supply

contracting and the development of a robust spot and financial markets resulted in greater price volatility in the commodity component of the gas supply. Figure 3 illustrates natural gas price volatility over time for natural gas at Henry Hub[2]. Volatility generally increases at times when demand approaches supply and capacity (deliverability, pipeline and storage) constraints (i.e. usually at winter peak demand periods). As volatility increases with rising prices there is a tendancy for customers to fix the price in their contracts to try to hedge their future prices.

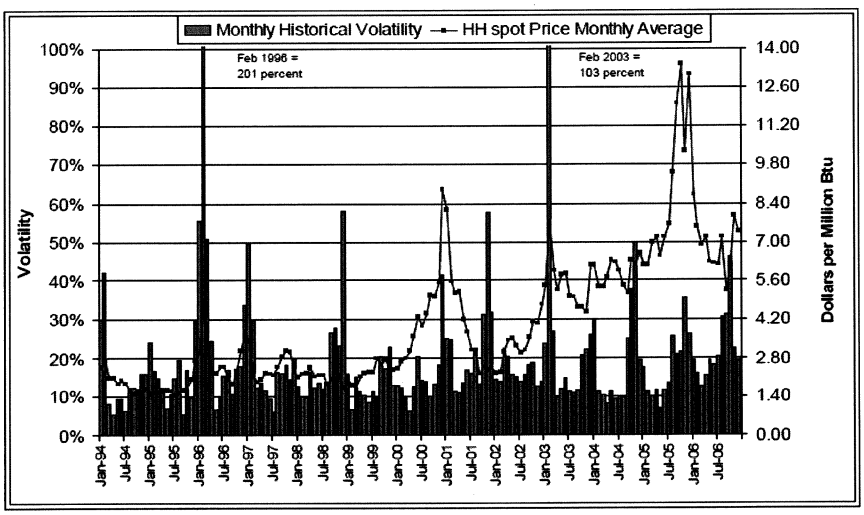


Figure 3: Natural gas price volatility 1994-2006

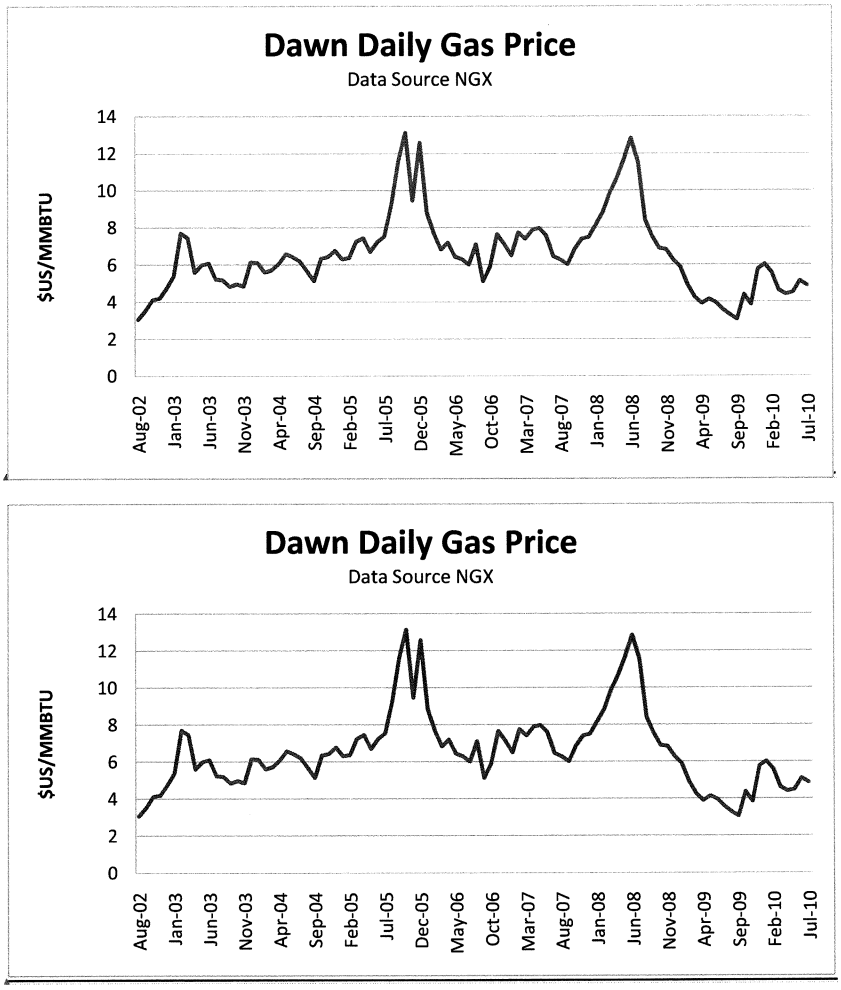
Today, natural gas prices are determined in the marketplace. There are physical and financial gas products that are available from gas producers, wholesalers and traders. Fixed and variable priced products are available on a daily, weekly, monthly, seasonal and yearly basis. NYMEX/CME provides ~~products that provide~~ traders, wholesalers and other market participants, products such as derivatives to help manage their commodity and basis risk. NGX (now owned by the TSX) also provides a trading platform for gas and electricity.

Natural Gas Pricing

Gas prices have dropped dramatically in the past 2 years (see Figure 4). The current price environment has prices at much lower price levels due to the recession driving down demand

[2] Henry Hub is the pricing point for natural gas futures contracts traded on the New York Mercantile Exchange ("NYMEX"). It is a point on the natural gas pipeline system in Erath, Louisiana

combined with a substantial increase in gas production (supply) from shale gas. Commodity price declines followed the increase in supply and reduction in demand.



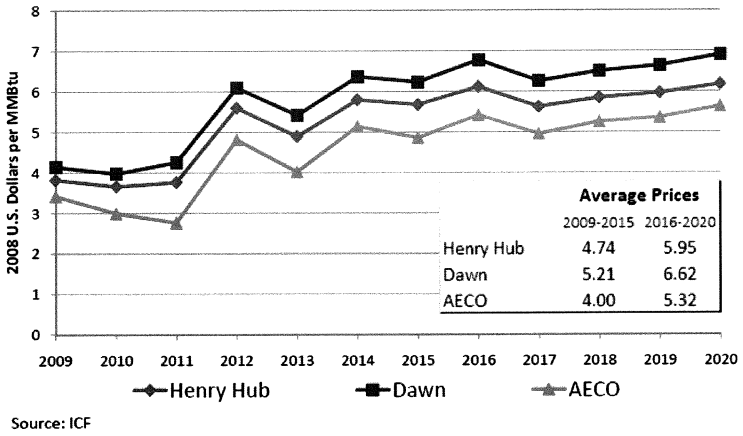
Dawn Daily Gas Price
Data Source NGX
$US/MMBTU
0
2
4
6
8
10
12
14
Aug-02
Jan-03
Jun-03
Nov-03
Apr-04
Sep-04
Feb-05
Jul-05
Dec-05
May-06
Oct-06
Mar-07
Aug-07
Jan-08
Jun-08
Nov-08
Apr-09
Sep-09
Feb-10
Jul-10

Figure 4: Dawn Daily Gas Price 2002-2010

Most gas forecasters as well as the OEB (most recent ICF document[3] Figure 5) are projecting a rise in gas commodity prices. Upward pressure on commodity prices could be driven by a move

[3] ICF 2010 Natural Gas Market Review August 18, 2010 Submitted to: Ontario Energy Board pg 11

to a carbon tax or cap and trade program as proposed under the Western Climate Initiative ("WCI") (planned to commence on January 1, 2012). Ontario is a partner in WCI.



Source: ICF

Figure 5: Forecasted gas price

Traders in the CME futures market believe that prices also have an upward trend as shown by Figure 6. These are the monthly future price settlements for future contracts at prices settled in the future.

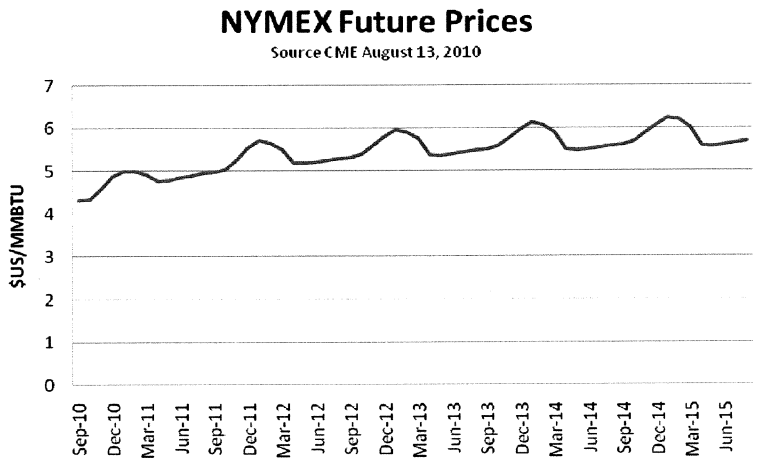


Figure 6: Gas futures prices

The graph shows the upward price trend as well as the seasonality of prices (i.e. higher prices in the winter months).

Direct Sales

Residential natural gas LDC customers have no contractual commitments to LDCs and therefore the residential customers can move easily from system gas to a retail contract. Upon retail contract expiry customers can also return to system supply. These features were intentionally designed into the LDC supply arrangements to facilitate direct sales. The origination of this was at the commencement of deregulation. The Ontario LDCs were not party to the federal provincial agreement on natural gas prices. In addition, the Alberta government imposed a requirement on the Ontario LDCs to take all existing gas under historical contracts with TransCanada. Absent doing so new gas supply originating from Alberta would not be granted an export license. One of the Ontario LDCs' counter balance to this position was the development of new Ontario direct purchase products and services that would allow the LDCs' customers to access "new" western Canadian gas at market prices. The LDCs utilized the COD provisions in the LDCs' western Canadian supply contracts. In other words, if Ontario gas consumers did not deem TransCanada's prices through the LDCs as competitive in the market place then the contracts could be displaced by lower priced direct purchase gas. This was further demonstrated in 1991 when Union and Enbridge renegotiated the bulk of their gas supply arrangements so that the price under those contracts became closer to the actual prevailing market price. The primary argument used in those negotiations was that absent a substantial

reduction in price, retail penetration would continue at an accelerated rate. As a consequence producers reduced their prices further. The direct sales activity of Retailers allowed the market force to bear on the market derived price in the LDC supply contracts. ~~This~~The evolution of direct sales is shown on the timeline, Figure 7.

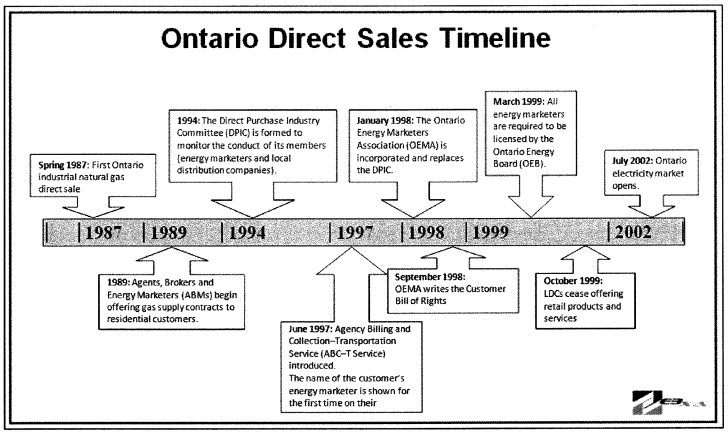


Figure 7: Ontario gas direct sales timeline

When Retailers take on a contract obligation to supply a residential customer they take on gas supply obligations and distributor obligations that must be honoured to the end of the retail contract term. Failing to meet their supply obligations results in costs that the Retailer must pay under their supply contracts. As a consequence it is normal business practice for Retailers to ensure that their retail contracts obligate consumers to take the supply and services in accordance with the terms of their agreements.

Direct Purchase Codes of Conduct Evolution

After Retailers started selling gas to residential consumers the Retailers (then referred to as Agents, Brokers and Marketers ("ABMs") and LDCs met to develop procedures for processing enrolments and to develop a form of self regulation. In 1994 the Direct Purchase Industry Committee ("DPIC") was established (as shown in Figure 7).

DPIC set out codes of conduct for Retailers, as well as, worked with the LDCs to develop processes for processing customer sign ups in a systematic manner. Systems and procedures evolved over time to help ensure that customer enrolments were managed in the most customer responsive manner. New products such as the Enbridge designed ABC-T service were introduced.

Ontario Retail Gas and Electricity Markets

The Ontario Energy Marketers Association ("OEMA") was formed in 1998 and continued with the approach initiated by DPIC. OEMA developed the Customer Bill of Rights in September, 1998. OEMA subsequently became a sub committee of the Ontario Energy Association.

The Ontario Energy Board initiated licensing for marketers in the spring of 1999. This included adoption of new codes of conduct. The OEB codes of conduct have evolved further and the OEB has recently commenced a stakeholder consultation process (EB-2010-0245) to replace the current codes with new codes in accordance with the recently revised Energy Consumer Protection Act. The Board intends to:

> "establish a new framework for the regulation of the activities of licensed electricity retailers and gas marketers ("suppliers"). Certain of the Board's existing regulatory instruments applicable to the activities of suppliers will need to be aligned- with the ECPA, and new rules developed in the context of the enhanced consumer protection environment inherent in the ECPA"[4].

Retail Gas Customer Activity

LDC gas pricing lags the market price due to the PGVA clearing mechanism. This lag historically had been a source of market evolution problems. When gas prices lagged the market substantially it was difficult for consumers to know what their LDC price would be over time so that they could compare it to a fixed price multi year retail offer.

[4] Ontario Energy Board web site:
http://www.oeb.gov.on.ca/OEB/Industry/Regulatory+Proceedings/Policy+Initiatives+and+Consultations/Consumer+Protection+ECPA#2010082

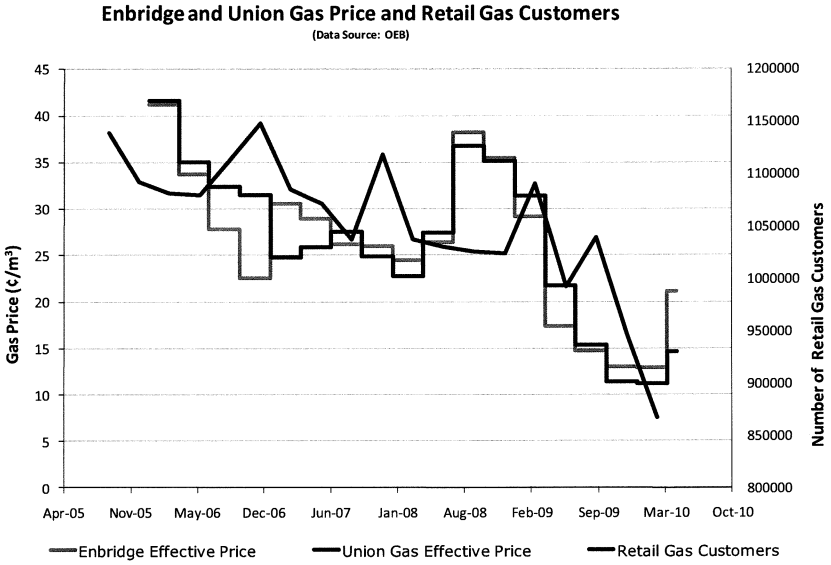


Figure 8: Gas prices and number of customers over time

Since 2005 there have been 2 very significant natural gas price drop periods. In both cases as shown in Figure 8 as the prevailing LDC system supply prices fell two things can be observed over time:

1. Retailer customer levels fell when the LDC's price dropped dramatically and rapidly
2. Customer return to system activity increases.

This has been observed since natural gas deregulation began in Ontario. LDC's prices are variable and lagged the market price because the PGVA accounts were initially only cleared once they met certain criteria (magnitude of the variance, price forecast and time of the prior cost adjustment). Subsequently the OEB approved quarterly rate adjustment mechanisms increasing the predictability of the timing of gas cost changes. As prices and volatility rise customers move to fixed priced direct purchase contracts to lock in the longer term fixed price to try to avoid higher prices and avoid the price volatility to the upside[5][6]. LDCs can not offer

[5] The Future of Retail Energy Markets, Catherine Waddams Price, The Energy Journal, 29(2008) Issue 2 p125-148

[6] VaasaETT World Energy Retail Market Ranking Fourth Edition, October 2008, pg8

fixed price contracts therefore this is a natural outfall of the current regulatory construct and the Ontario gas ~~markets~~market.

Ontario Electricity Market Evolution

In 1998, the Ontario government legally committed to electricity market deregulation by passing Bill 35, the Energy Competition Act. The Ontario government established the Market Design Committee ("MDC") in November 1998. The MDC was tasked with the responsibility of designing a new unregulated electricity market. The MDC submitted its recommendations to the Ontario government early in 2000.

The new Ontario wholesale electricity market opened on May 1, 2002.

Prior to deregulation Ontario Hydro was the primary supplier of electricity to Ontario. Ontario had approximately 360 electric LDCs. This number was reduced by mergers and acquisitions such that today there currently is less than 90 electric LDCs.

Under the new Electricity Act, the former Ontario Hydro was broken into a number of new entities/corporations including the following:

1) **Hydro One**
    a. The transmission company
    b. Hydro One Networks a distribution company serving numerous communities
2) **Ontario Power Generation** ("OPG"): owns and operates generation assets
3) The **Independent Electricity System Operator** ("IESO") (formerly IMO it became the IESO after spinning off the Ontario Power Authority ("OPA"): The IESO plans for the short term, operates and dispatches the system and operates the physical market accepting offers from generators and bids from direct connected customers. The OPA plans for the long term, develops Conservation and Demand Management ("CDM") programs and enters into and manages contracts for generation.
4) The **Ontario Electricity Financial Corporation** ("OEFC"): responsible for managing the financial obligations of certain Non Utility Generation ("NUGs") contracts and the residual stranded debt of Ontario Hydro.
5) The **Electricity Safety Authority** ("ESA"): is responsible for the safety protocols of the electricity system.

The new act also created new responsibilities for the OEB. These combined changes provided for: access to the electricity transmission system, development of the wholesale electricity market, and retail choice.

Electricity Bill Components

Electricity was deregulated in Ontario on May 1, 2002. The MDC recommended that for a period of four years after the opening of the market, 90% of OPG's expected domestic energy sales be subject to an average price cap of 3.8 cents/kWh. The MDC's Retail Market recommendations were significantly different than what has emerged in Ontario.

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> **4-3** We recommend that all local distribution companies should be required to offer to all customers' electricity supply priced at a "smoothed" pass-through of the wholesale market spot price, based on an average forecast price, adjusted perhaps on a quarterly basis, and including a regulated recovery of administrative costs. The local distribution company may contract out fulfilment of this regulated obligation to other appropriate parties.
>
> **4-4** We recommend that all local distribution companies should also be required to offer to customers the option of buying energy at the wholesale market hourly spot price, including a regulated recovery of administrative costs. The local distribution company may contract this regulated function out to other appropriate parties.
>
> **4-5** We recommend that the spot price pass-through bill amount be the actual wholesale spot price multiplied by the customer's usage in each interval for customers with interval meters. For customers with watt-hour meters, an appropriate profile should be used to allocate total kilowatt-hours over the billing period to the individual intervals for pricing purposes.[7]

Retailers were represented and participated in the MDC and relied on the MDC recommendations in preparation for market opening.

Direct connected large volume customers were not eligible for the Regulated Price Plan ("RPP"). They either purchase their power through bilateral contracts with generators, from wholesalers or from the open hourly IESO market.

Residential customer bills have the following price components:

1) **Delivery Charge:** this is a charge that varies with use. It includes the costs of transmission (Hydro One) and distribution. Both charges include loss factor adjustments.

    a. A fixed LDC customer charge. This is a regulated fixed monthly charge which recovers the fixed costs that have been approved by the OEB. It varies from LDC to LDC depending on the LDC's fixed costs and overall residential customer load profiles. A variable charge recovers the LDC's variable costs

    b. **Hydro One Transmission Charge:** This charge covers the costs of delivering electricity from the generators to the LDC. It includes the costs to build and maintain the transmission and distribution lines, towers and equipment and

[7] Market Design Committee –Second Interim Report – List of Recommendations, Chapter Four – Retail Competition , pg 15

operate the provincial electricity systems. Some of these charges are fixed and do not change from month to month, while others are variable and increase or decrease depending on the amount of electricity used.

2) **The Electricity Charge**. For residential customers this can be the RPP or a Retailer price. The RPP applies to residential and small business customers who consume less than 150,000 kWh of electricity per year. It also used to apply to hospitals, schools, and municipalities. It now only applies to smaller customers with a demand less than 50 ~~kw~~kW. Under the regulated RPP the electricity charge is a variable charge priced on a per kilowatt hour basis. Currently there are 2 forms of electricity charges: 1) a tiered charge adjusted on a seasonal basis and 2) a Time-of-use ("TOU") rate. Most customers will be on TOU rates by the spring of 2011. Under the Retailer contract the price is usually a fixed price for a fixed period of time.

3) **Regulatory Charges:** are the costs of administering the wholesale electricity system and maintaining reliability of the provincial grid and ~~include~~includes the costs associated with funding the Ministry of Energy and Infrastructure's conservation and renewable energy programs. It includes the costs of the IESO as approved by the OEB.

4) **Debt Retirement Charges:** A charge of 0.7 cents per kWh set by the Ontario Ministry of Finance to pay down the residual stranded debt of the former Ontario Hydro.

5) **The Provincial Benefit**: "The Provincial Benefit ensures reliability by providing adequate generating capacity for Ontario. It accounts for differences between the spot market price and the rates paid to regulated and contracted generators. As a result, its value may be positive or negative, depending on the fluctuation of prices in the spot market."[8] and

6) **Harmonized Sales Tax** ("HST"): Effective July 1, 2010 the new HST is applied to the entire electricity bill.

Figure 9[9] shows the 2 different rates under the RPP.

[8] http://www.ieso.ca/imoweb/siteshared/provincial_benefit_faq.asp

[9] Source IESO http://www.theimo.com/imoweb/infoCentre/ic_index.asp , August 14, 2010

Ontario Retail Gas and Electricity Markets

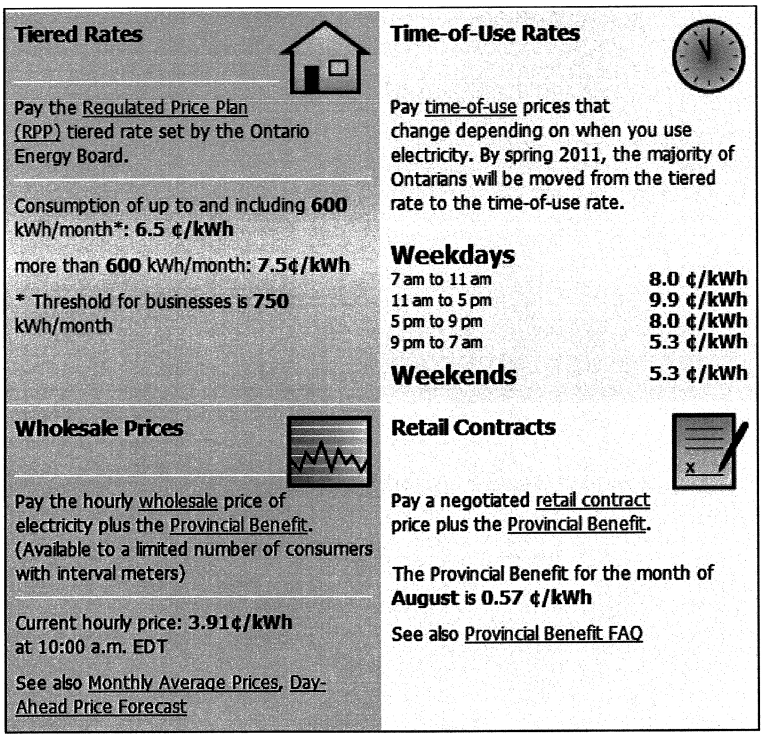


Figure 9: Rates under RPP

Figure 10[10] shows the electricity prices for consumers on the RPP from November 2002 onward. It also shows the rates for TOU and Two Tier pricing.

[10] OEB web site

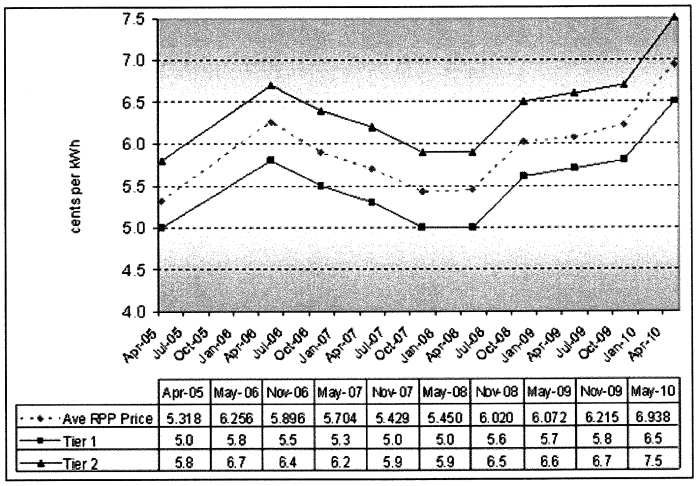
Electricity Prices for Consumers on the Regulated Price Plan (RPP)
(April 2005 - May 2010)

	Government		Ontario Energy Board										
	Nov-02* (¢/kWh)	Apr-04** (¢/kWh)	Apr-05 (¢/kWh)	May-06 (¢/kWh)	Nov-06 (¢/kWh)	May-07 (¢/kWh)	Nov-07 (¢/kWh)	May-08 (¢/kWh)	Nov-08 (¢/kWh)	May-09 (¢/kWh)	Nov-09 (¢/kWh)	May-10 (¢/kWh)	Chg from Nov '09
Average RPP Price***	*4.3*	*5.1*	*5.318*	*6.256*	*5.896*	*5.704*	*5.429*	*5.450*	*6.020*	*6.072*	*6.215*	*6.938*	*0.723*
Two-Tier (non-TOU)													
Tier 1 (below threshold)	*n/a*	4.7	5.0	5.8	5.5	5.3	5.0	5.0	5.6	5.7	5.8	6.5	0.7
Tier 2 (above threshold)	*n/a*	5.5	5.8	6.7	6.4	6.2	5.9	5.9	6.5	6.6	6.7	7.5	0.8
Time-of-Use (TOU)													
Off-Peak	*n/a*	*n/a*	2.9	3.5	3.4	3.2	3.0	2.7	3.9	4.2	4.4	5.3	0.9
Mid-Peak	*n/a*	*n/a*	6.4	7.5	7.1	7.2	7.0	7.3	7.3	7.6	8.0	8.0	0.0
On-Peak	*n/a*	*n/a*	9.3	10.5	9.7	9.2	8.7	9.3	8.8	9.1	9.3	9.9	0.6

* *Bill 210 price freeze. Price was set well below the cost to supply consumers and contributed over $1 billion to the debt. Should not be used to compare current RPP prices.*
** *"Interim" tiered prices set by the Government (costs of NUG contracts entered into by Ontario Hydro not included. RPP prices include NUG contract costs).*
*** *The "average RPP price" is used to set both the RPP tiered and RPP time-of-use (TOU) prices.*

Figure 010: Rates under both two-tier and TOU rates

Figure 11[11] shows the average RPP price and the 2 Tier price in graphical form.



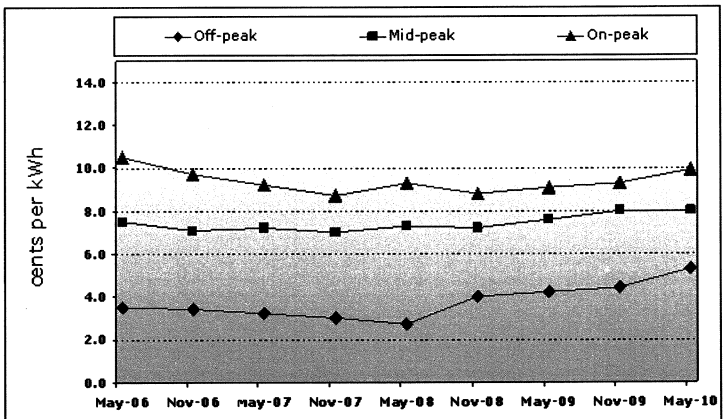
	Apr-05	May-06	Nov-06	May-07	Nov-07	May-08	Nov-08	May-09	Nov-09	May-10
Ave RPP Price	5.318	6.256	5.896	5.704	5.429	5.450	6.020	6.072	6.215	6.938
Tier 1	5.0	5.8	5.5	5.3	5.0	5.0	5.6	5.7	5.8	6.5
Tier 2	5.8	6.7	6.4	6.2	5.9	5.9	6.5	6.6	6.7	7.5

Figure 11: Average RPP and two-tier prices

[11] OEB Web Site Regulated Price Plan Historical Snapshot (http://www.oeb.gov.on.ca/OEB/Consumers/Electricity/Electricity+Prices) August 12, 2010

Figure 12[12] shows the changes in TOU pricing over time.

Time-of-Use Prices: Historical Snapshot



	May-06	Nov-06	May-07	Nov-07	May-08	Nov-08	May-09	Nov-09	May-10
Off-peak	3.5	3.4	3.2	3	2.7	4	4.2	4.4	5.3
Mid-peak	7.5	7.1	7.2	7.0	7.3	7.2	7.6	8	8
On-peak	10.5	9.7	9.2	8.7	9.3	8.8	9.1	9.3	9.9

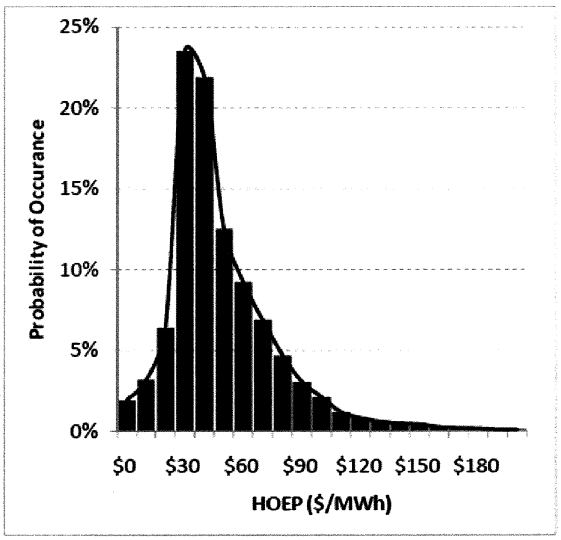
Figure ~~2~~12: TOU pricing over time

Hourly Ontario Electricity Price

The IESO monitors the market and neutrally matches bids to buy and offers to sell electricity. The IESO determines a uniform electricity price for the province every 5 minutes. The Hourly Ontario Electricity Price ("HOEP") is the arithmetic average of the twelve 5-minute electricity prices in that hour. The HOEP is used to determine prices in the Ontario market. Navigant in its most recent report[13] to the OEB has forecasted the probability distribution for the HOEP. (Figure 13). Navigant has also forecasted the HOEP and the Global Adjustment.

[12] OEB web site Regulated Price Plan Historical Snapshot (http://www.oeb.gov.on.ca/OEB/Consumers/Electricity/Electricity+Prices) August 12, 2010

[13] OEB Navigant RPP report Ontario Wholesale Electricity Market Price Forecast April 7, 2010 pg 17



Source: NCI analysis of IESO data (May 2002 to March 2010)

Figure ~~3~~13: Forecasted probability distribution of HOEP

Global Adjustment

The Global Adjustment applies to wholesale market customers. "The Global Adjustment represents the difference between the total contract cost of the various contracts it covers (for Ontario Power Generation nuclear and prescribed hydro, Bruce nuclear, gas plants, renewable generation, OPG coal, CDM, etc.) and the market value of the contracted generation. The Global Adjustment changes due to changes in the contracts it covers and fluctuations in the market value of the contracted generation.

This is illustrated in Figure 15, which shows how the Global Adjustment has changed, and is expected to change, over the previous (May 2009 to April 2010) and upcoming (May 2010 to April 2011) RPP periods. Consumers pay the full cost of the contracts covered by the Global Adjustment, either through market costs or through the Global Adjustment itself. The Global Adjustment fluctuates as market prices rise and fall, but the general trend in the total cost (market cost plus Global Adjustment) has been a steady increase."[14]

[14] Price Plan Price Report May 1, 2010 To April 30, 2011 Ontario Energy Board, April 15, 2010 pg 11

Figure 14 from the OEB's Market Surveillance Panel shows the historical average HOEP and the effective price adjusted for the Global Adjustment and the OPG Rebate.[15]

Figure 1-2: Monthly Average HOEP Adjusted for OPG Rebate and Global Adjustment, April 2005–April 2009 ($/MWh)

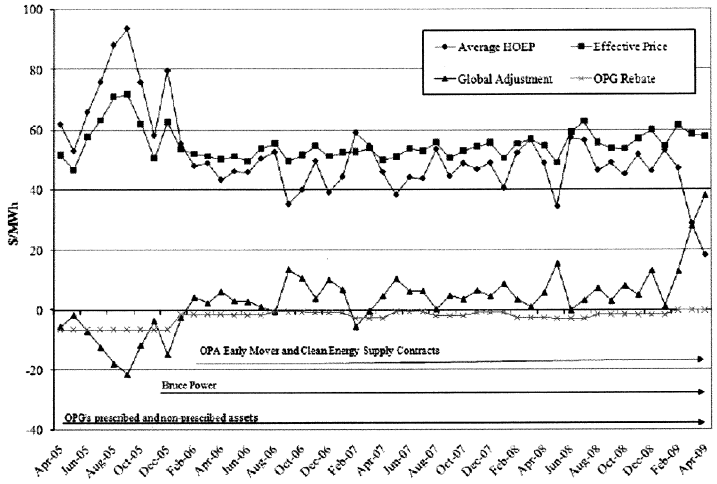


Figure 14: Historical Average HOEP and Effective Price

Provincial Benefit

Residential ~~customers~~customer's electricity prices are adjusted by the Global Adjustment. For residential customers it is called the "Provincial Benefit". The Provincial Benefit rate is set to reflect the difference between the spot market price and the regulated rate paid to Ontario Power Generation's baseload generating stations and payments made to suppliers that have contracts with the OPA. These include: new gas-fired facilities, renewable facilities (like wind farms, solar and bio), demand response programs and Non-Utility Generators.

The Provincial Benefit applies to "business customers who pay the spot market price and customers who have signed a contract with a licensed electricity retailer. It appears as a separate line on the bill. For customers who pay the Regulated Price Plan, it is factored into the rate set by the Ontario Energy Board, and does not appear as a separate line item."[16]

[15] Market Surveillance Panel Report November 2008 –April 2009, July 2009, pg 7

[16] http://www.ieso.ca/imoweb/siteshared/provincial_benefit_faq.asp

~~The Provincial Benefit increases and decreases in response to changes in the spot market price. Over the last year, the spot market price has been unusually low. This has been a result of low demand (due to the economy and the weather) and good availability of generation. The Provincial Benefit has been higher in order to cover the additional costs of the contracted and other regulated generation.~~

Ontario's Future Electricity Prices

As Ontario's supply mix changes to accommodate the phase out of over 6400 MW of coal fired generation average electricity commodity prices are expected to rise~~>~~. This will be driven by the impacts of the new Feed In Tariff's ("FIT") higher priced OPA contracted generation plus a substantial increase in new gas fired generation. All these forms of generation are priced at substantially higher prices than the current prevailing market price.

In addition, the proposed cap and trade program would also result in an increase in electricity prices. Ontario is a member in the Western Climate Change Initiative ("WCI"). Under the WCI proposal Ontario electricity would be subject to the cap and trade program commencing January 1, 2012. Under the WCI program this would result in further upward pressure on Ontario electricity commodity prices.

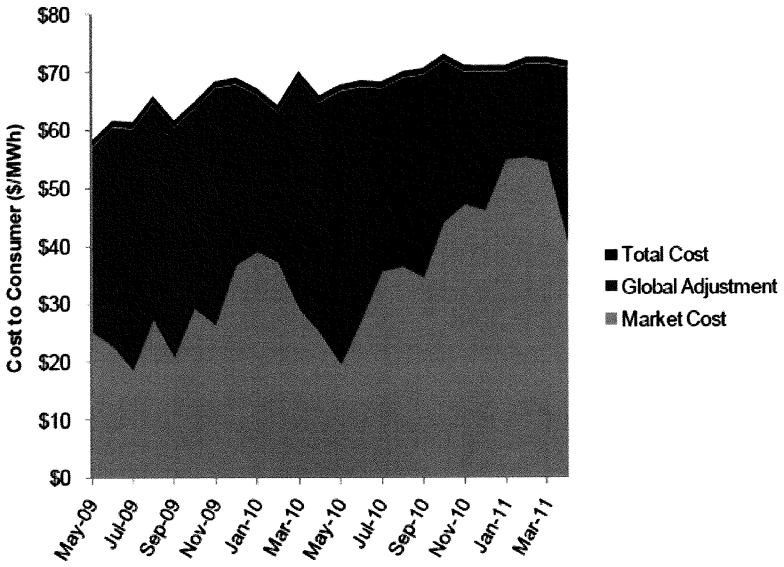


Figure ~~5~~15: Forecasted total cost (Source: Navigant)

Navigant has also provided the OEB a forecast[17] of the Total Cost to Consumers, the Market Cost and the Global Adjustment as shown in Figure ~~16~~15. This shows the relationship of the HOEP (Market Cost) to the Provincial Benefit. As the HOEP rises the Provincial Benefit falls.

Market Design Changes Under Way

The IESO as part of its 2011 Business Plan is proposing to ~~established~~establish a new Market Design Committee to consider and recommend changes to Ontario's electricity market. This committee is expected to be formed in September 2010 with their recommendations being completed within 1 year. A "Market Design Roadmap" will be produced by the committee.

The new regulations proposed by the Ontario government would ~~proposes to~~ change the name of the Provincial Benefit to Global ~~adjustment~~Adjustment to reduce customer confusion.

The OPA will be filing a new Integrated Power System Plan later this year.

Trends in Electricity Consumer Retailer Contracting

Figure 16 illustrates the total number of customers purchasing retail electricity over time.

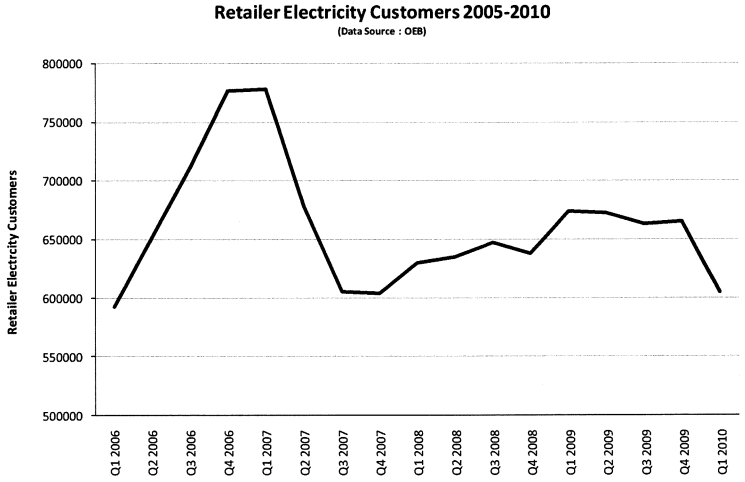


Figure 16: Retailer electricity customers over time

[17] Navigant RPP report April 15, 2010 pg 12

Figure 17 shows the number of retail customers over time compared to the electricity price components.

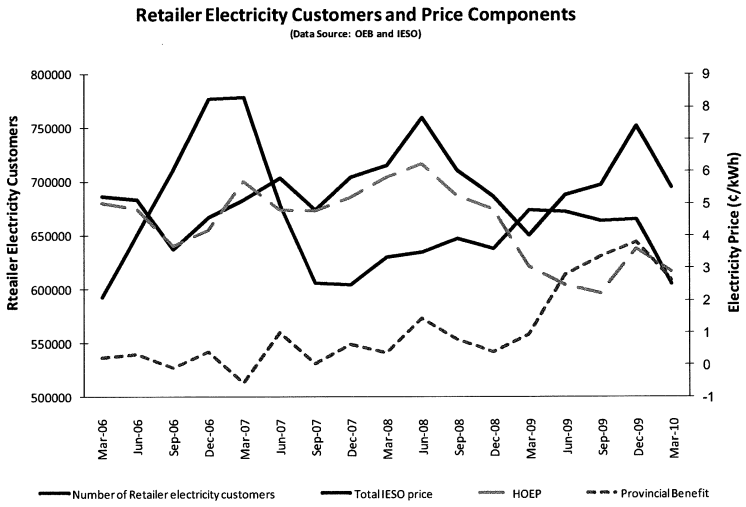


Figure 17: Retailer electricity customers and price components

As the Provincial Benefit rises the number of retail customers falls, as shown in Figure 18. As prices and volatility rise customers move to fixed priced direct purchase contracts to lock in the longer term fixed price to try to avoid higher prices and avoid the price volatility to the upside. LDCs can not offer fixed price contracts therefore this is a natural outfall of the current regulatory construct and the electricity and gas markets.

Provincial Benefit and Customer Enquiries

As described above the Ontario government introduced a price adjustment called the Provincial Benefit. Small consumers such as residential customers pay the equivalent of the Global Adjustment which is called the Provincial Benefit. The Provincial Benefit increases and decreases in response to changes in the spot market price. Over the last year, the spot market price has been unusually low. This has been a result of low demand (due to the economy and the weather) and good availability of generation. The Provincial Benefit has been higher in order to cover the difference between the contracted/regulated prices and the market based spot price.

explanation is that "the observed decisions are as a consequence of large consumer decision errors that may either occur due to the high complexity of the specific market environment, or perhaps more reasonably due to the effect of some deliberate supplier strategy". The authors investigated the possibility that the poor decisions were the result of "mis-selling tactics" (e.g. cold calling and doorstep selling) and found that mis-selling "does not appear to be a satisfactory explanation of the inefficiency of ~~consumers~~consumers' choices within this dataset" and suggested that the errors are more likely related to the "inherent complexities of the market in question".

Figure 19 shows the number of enquiries logged by the Ontario Energy Board ("OEB")[22] versus the change in the Provincial Benefit. As can be seen the number of contract enquiries rises almost parallel with the rising level of the Provincial Benefit. Although the OEB does not break out the contract enquiries (on their web site) by type it appears that the lack of customer understanding of the Provincial Benefit may be significantly contributing to the number of contract enquiries.

Field Code Changed

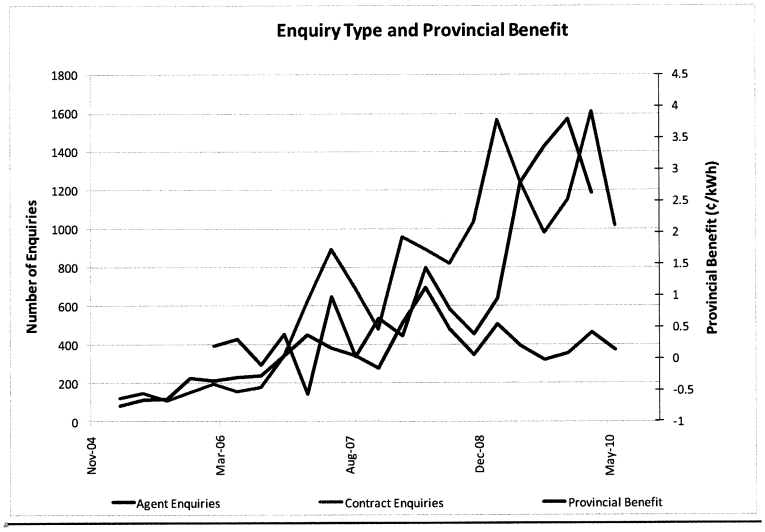


Figure 19: Customer Enquiries and Provincial Benefit

[22] http://www.oeb.gov.on.ca/OEB/Industry/Media+Room/Publications/Consumer+Reports/Overall+Consumer+Enquiries+and+Issues

Observations

1. The retail gas market gas price is transparent in contrast to the Ontario electricity market.

2. As prices and volatility rise customers move to fixed priced direct purchase contracts to lock in the longer term fixed price to try to avoid higher prices and avoid the price volatility to the upside. LDCs can not offer fixed price contracts therefore this is a natural outfall of the current regulatory construct and the electricity and gas markets.

3. Due to significant changes and complexity of the electricity price setting mechanisms the Ontario retail electricity market price mechanisms are confusing and the price ~~aand is~~and its components are not transparent. This is especially the case due to unexpected significant changes after market opening (i.e. such as the shift to RPP and the addition of the Provincial Benefit). In addition the terminology used in the electricity market contributes to a lack of clarity. This appears to be recognized by government agencies given the name change proposed for the Provincial Benefit as well as the IESO's commencement of a market road map plan.

4. The number of retail gas accounts decline with significant and rapid LDC commodity price declines.

5. The Provincial Benefit appears to have contributed to the reduction in retail electricity accounts and likely also to enquiries with the OEB.