Ontario Five Year Wholesale Power Price Forecast

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Table of Contents

1.0 Executive Summary ... 6
2.0 Background ... 8
2.1 Forecasted Growth in Demand and the Resulting Supply Gap .. 9
2.2 Key Ontario Electricity Price Drivers ... 9
2.3 Objectives ... 10
3.0 Structure of Ontario Energy Supply ... 11
3.1 Nuclear ... 11
3.2 Coal ... 11
3.3 Hydro ... 11
3.4 Imports ... 12
3.5 Renewables and Clean Energy ... 12
3.6 Gas Fired Combined Cycle Gas Turbines (CCGT) ... 13
3.7 Reserve Margins ... 14
4.0 Structure of Ontario Energy Pricing ... 15
4.1 Existing Pricing Process ... 15
4.2 Historical Wholesale Market Prices ... 16
4.3 Snapshot: Timing and Volume of Demand in Ontario ... 16
4.4 Summer Price Picture: ... 17
4.5 Winter Price Picture for Wholesale Markets ... 17
4.6 Frequency of High Price Events ... 18
5.0 5 Year Forecast of Electricity Prices ... 18
5.1 Influencing Factors - Summary ... 18
5.2 Assumed Supply Scenario ... 19
5.3 Future Natural Gas Generated Electricity Prices ... 20
5.4 Key Rising Price Driver: Gas Replacing Coal ... 23
5.5 Illustrations of the Impact on Prices from Changes in Supply. 24
5.6 Demand Growth & Demand Side Management – Moderate Determinants of Price ... 27

5.7 Mitigating Factors for the High Price Scenario 27
5.8 Forecast of Prices 30
6.0 Cost Implications for a Proxy Industrial User 31
7.0 Conclusion 32
Appendix A: Green Valuation 33
Appendix B: Methodological Note 37
Key References 38
Other References 38

List of Figures and Tables

Figure 1: How Ontario Currently Meets Base and Peak Loads 8
Figure 2: Net Requirement for New Supply – High, Low and Medium estimates from the IMO 9
Figure 3: Ontario Wholesale Prices vs. Neighbouring Jurisdictions (cents/KWh) 12
Figure 4: Generation vs. Peak Demand - With Renewables 13
Figure 5: Hourly Ontario Demand in MW 16
Figure 6: A typical Summer Day for Electricity Markets in Ontario 17
Figure 7: Typical Winter Day for Electricity Markets in Ontario 17
Figure 8: Future Prices of Natural Gas on the New York Mercantile Exchange 20
Figure 9: Natural Gas Prices in the Henry Hub Trading Market 21
Figure 10: Natural Gas Prices in Ontario 21
Figure 11: Natural Gas Prices in Canada 22
Figure 12: Baseline 24
Figure 13: Coal 2005 Shutdown 25
Figure 14: Coal Shutdown Assumption 100% by 2007 25
Figure 15: Nuclear Refurbished at 50% Increase in the Cost Estimate with Coal Shutdown 26
Figure 16: Nuclear - Bruce A Unit 13 Shutdown as Scheduled in 2009 27

Table 1: Gas Price and Price Volatility 14
Table 2: Price Setting Fuel in Ontario (since market opening) 16

Table 3: Future Price Estimates Used for Scenarios 19

Table 4: Gas Price and Heat Rate 22

Table 5: Cost Implications for Present day, and Future 31

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Glossary

CCGT	Combined Cycle Gas Turbine
CO_2	Carbon Dioxide
GHG	Greenhouse Gas
GJ	Gigajoule
GWh	Gigawatt hour
HOEP	Hourly Ontario Electricity Price
IMO	Independent Market Operator
KWh	Kilowatt hour
MCP	Market Clearing Price
mmBTU	10 million metric British Thermal units
MWh	Megawatt hour
NO	Nitric Oxide
REC	Renewable Energy Certificate
SO_2	Sulphur dioxide

1.0 Executive Summary

Ontario's robust economy and increasing population base have created rising demand for electricity of approximately 1.4% per year over the past decade. Price is currently moderate in the Ontario market because demand (average peak usage around 24000 MW) can typically be met by low cost supply in Ontario hydro (~10%), nuclear (~40%) and coal (~25%) facilities. Peak power requirements are then fulfilled by oil, natural gas and expensive pumped hydro.

This situation is expected to change dramatically over the next 5-15 years as a 15,000 MW gap will be created between supply and demand due to the retirement of 7,500MW of coal generation and an increase of 8,000MW of peak demand(1). [1]. Wholesale prices in Ontario will likely resemble those in neighbouring US jurisdictions, averaging $70-90 per delivered MWh, with price spikes reflecting increasing gas price volatility.

Currently, the average Hourly Ontario Electricity Price (HOEP) is in the $45-55/MW range. However, in the absence of any near term large scale supply alternatives other than wind and demand reduction measures, the Province will be critically dependent in the medium term on expensive gas-fired generation and external sources of electricity. Energy costs will be higher and more volatile as a result[2]. While aggressive demand reduction measures may help to mitigate the price pressure, more expensive generation sources (i.e. renewables, natural gas, imports) will play an increasingly important role in setting the province's market clearing price for future electricity. Whether pricing stabilizes over the long term will depend on policy decisions to invest in new nuclear plants, improve interconnection with Manitoba or develop large scale (>250MW) wind and hydro projects in the north. With the exception of wind, these are all 10 year undertakings.

The purpose of this review was to provide an estimate of Ontario electricity price ranges for industrial and commercial users during the 2005 to 2010 time period under several different supply scenarios for the Ontario electricity wholesale market. The review considers the key supply and demand factors for the Ontario electricity system by looking at the various generating fuels and their cost supply forecast.

With increased reliance on existing and underused gas fired generation, combined with rising gas prices leads inescapably to the conclusion that industrial and commercial energy users could be paying at least 50% more for their electricity over the next few years. The key risks to the high price scenario are from major changes to government policy, gas prices or market structure. The review considers a possible change to market structure with tariffs being implemented for industrial customers. This alteration leads to a 10% increase in average industrial power rates.

The chart on the next page summarizes the high price scenarios examined in this review. It gives a breakdown of the key price drivers for the next five years in the Ontario wholesale electricity market.

[1] Electricity Conservation and Supply Task Force (ECSTF), p 20.
[2] ECSTF p.25

Annual High Price Scenarios are Summarized Below

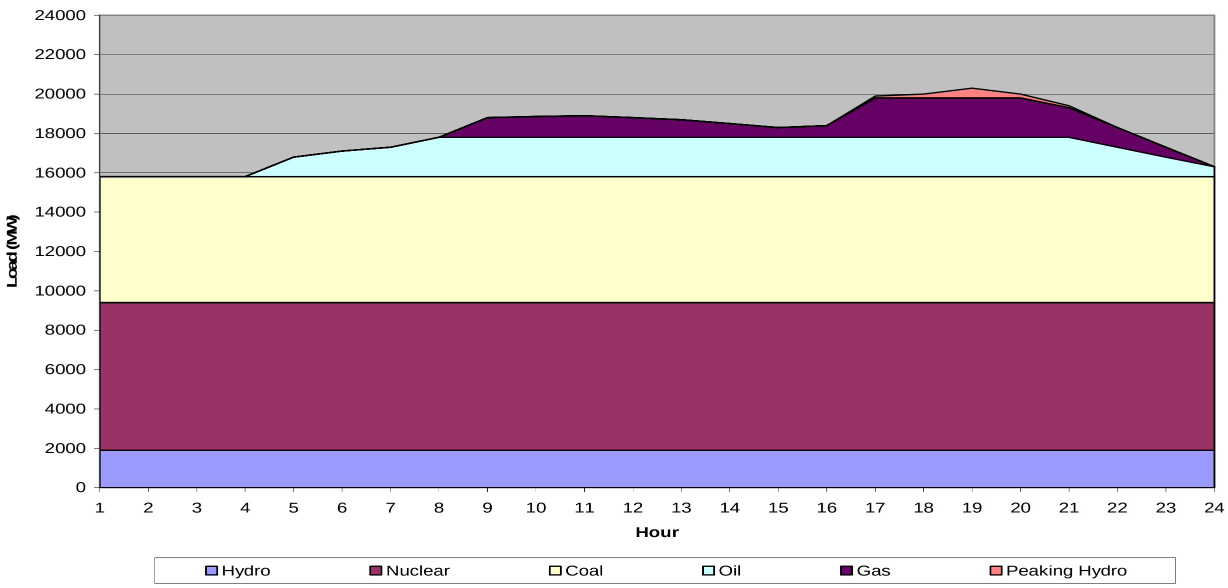
Year	Weighted Average Price	Explanation
2005	$53/MWh	Base Case: Reflects the prices experienced over the last year. 50% of the time prices are in the $35 range, and in the $70 range the other half of the day.
2006	$57/MWh	Scenario A: Lakeview Coal plant is shut down removing 20% of the coal generation. 38% (9hrs) of the day the Hourly Ontario Electricity Price (HOEP) is in the low price range, and 62% of the time it is set by higher priced gas generation and peaking plants.
2007	$75/MWh	Scenario B: The rest of the Coal is shut down. The HOEP is in the high price range 100% of the time. Average price is thus set somewhere in the $60 to $90 range. Even over night, during off peak hours there in not enough low cost capacity to move prices into the lower levels set by the nuclear generating stations.
2008	$72/MWh	Scenario C: Nuclear refurbishment leads to an additional 5% of supply coming from Pickering generating station. As a result, the demand line is closer in the illustration to lower priced generation. While the demand line remains in the higher priced category of supply, it is in the lower end of that range for more hours than in Scenario B. The distribution is approximately 40% of the time at $60/MWh, 40% at $75/MWh and 20% at 90/MWh.
2009	$75/MWh.	Scenario D: Bruce A Unit 3 shutdown as scheduled, removing 5% of the low cost nuclear generation from available resources. This returns the market back to a similar situation as Scenario B, when all the coal is removed. Average price would increase again to $75/MWh.

2.0 Background

Ontario's expanding economy and increase in population base have meant constant growth in demand for electricity in the Province. Over the past ten years, overall electricity demand has increased an average of approximately 1.4% per year. Peak electricity demand, grew at an average annual rate of 1.7% over the same period.

As a result of this ongoing economic growth, Ontario residents and industry now utilize around 24000 MW of electricity during peak daytime hours. On average, approximately 75% of this demand is met through low cost generation from hydro (~10%), nuclear (~40%) and coal (~25%) facilities. Peak power requirements are then fulfilled by oil, natural gas and expensive pumped hydro (refer to Figure 1). Additional information and context on Ontario's current supply is provided in Section 2.

Figure 1: How Ontario Currently Meets Base and Peak Loads



Source: ECSTF: Ensuring Adequate Supply, p47.

It is useful to note that the economy of Ontario grew by 4.3% over the last year, which implies that electricity demand is significantly de-coupled from GDP growth. Much of this reduction in electricity demand growth is due to fuel switching to natural gas for home heating. While good for moderating electricity demand growth, the switch to natural gas puts upwards pressure on demand and price for this resource and thus the price of electricity, since marginal prices are typically set by a combination of peak fuel sources that include gas fired generation. For a more detailed discussion on the relationship between natural gas prices and electricity prices, please refer to Section 5.1.

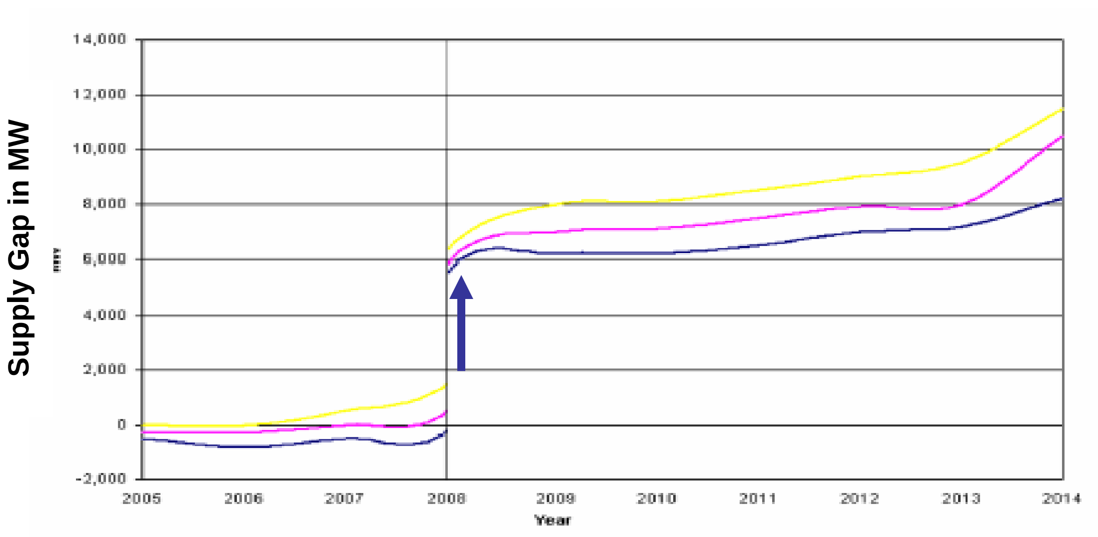
2.1 Forecasted Growth in Demand and the Resulting Supply Gap

While prices are currently moderate in the Ontario market because supply is relatively equal with demand, the chart below illustrates how this could rapidly change as we head into the future. The three lines represent the Independent Market Operator's (IMO) high, low and medium demand forecasts. Even at the lowest demand projection, a wide gap will be created between supply and demand, when existing coal generation facilities are shut down in 2007.

The IMO's median demand forecast projects that energy consumption will continue to grow 1.1% per year[3]. Under this scenario annual peak demand is predicted to rise from just over 24,000 MW in 2004, to almost 27,000 in 2013. Including reserve requirements for the same period of time, the figures rise from under 28,000 MW to over 30,000 MW. Assuming similar growth rates, peak demand would reach 32,000 MW in 2020 and with necessary reserves Ontario would require nearly 37,000 MW of capacity.[4]

Adjusting IMO forecasts with planned retirements of the coal generating station in 2005 results in a projected supply shortfall in 2007 of 5000-7000MW.

Figure 2: Net Requirement for New Supply – High, Low and Medium estimates from the IMO



Source: IMO 10 Year Outlook, April 29, 2004. p 11.

2.2 Key Ontario Electricity Price Drivers

Low cost supply has exceeded demand over recent years, with gas fired generation sitting idle due to lower marginal prices. Low cost coal fired generation is currently keeping the Hourly Ontario Electricity Price (HOEP) in the $45-55/MW range on average. This situation will likely change dramatically when the first coal fired generating station slated for closure, Lakeview GS, is taken off line in 2005.

[3] ECSTF
[4] ECSTF, p 20.

If no new capacity or demand reduction measures are taken, the Province will be critically dependent on idled gas-fired generation, or external sources of electricity. Energy costs will be higher and more volatile[5]. This situation could be exacerbated further by:

1. *Weather* - if summer temperatures are abnormally high or winter temperatures abnormally low, peak electricity demands increase significantly creating a greater supply gap, which then pushes up prices.
2. *The ongoing season shift* in peak electricity demand from winter to summer months. As more natural gas is required for electricity generation, less will be stored for the winter heating months thereby creating additional pressure on prices.

Demand reduction measures should be noticeable during the next five years if the government continues with its conservation push. However, these 'negawatts' will not be significant enough to offset the loss of inexpensive baseload coal fired generation.

New renewable/clean energy supply from the recent 300MW and 2500MW request for proposals will alleviate some pressure on baseload generation, however it will likely be three to five years away, and be generated at similar prices to gas-fired electricity (approximately $60-80/MWh price range).

As a result of these and other related factors, industry will continue to be exposed to greater amounts of gas fired generation and thus higher electricity prices as more expensive generation sources (i.e. renewables, gas, imports) play an increasingly important role in setting the province's market clearing price (refer to Sections 5.0 – 7.0) for future electricity.

2.3 Objectives

The purpose of this review was to provide an estimate of Ontario electricity price ranges for industrial and commercial users during the 2005 to 2010 time period under several different supply scenarios for the Ontario electricity wholesale market. A simplified model was developed that employed specific assumptions around future supply (i.e. the types and mix of generating fuels providing baseload and peak power), projected generation costs, overall demand and daily usage curves. The results were then analyzed to provide an estimate of the potential increase in electricity rates that a typical industrial/commercial user might pay between 2005 and 2010.

[5] ECSTF p.25

3.0 Structure of Ontario Energy Supply

The following section reviews each of the major sources currently supplying electricity to Ontario's grid, and their potential role in meeting Ontario's future electricity needs.

3.1 Nuclear

Nuclear currently provides upwards of 35% to 40% of the energy requirements in Ontario. However, problems have been experienced by the nuclear fleet over the past 5 years resulting in waning public confidence in its continued role of supplying baseload low price electricity. For the purposes of this review however, the most relevant information is that most of the nuclear resources are assumed to remain largely constant, with no new major shutdowns, and one addition – a refurbished Pickering A Unit 1. For this analysis, it was assumed that Bruce A Unit 3 will be removed from service as scheduled beginning in 2009 (900 MW), as per IMO information.

Pickering A Unit 1 is scheduled to return to service by Q4 2005 (515MW) at a cost of $900 million. The per MWh cost estimates for generation from a refurbished Pickering A Unit 1 are said to be in the $40-45/MWh range.[6]

3.2 Coal

Coal currently provides approximately 25% of Ontario's demand on average. This is equal to roughly 6,400 MW. The official plan for coal fired generation in Ontario is to phase out all generation, starting with Lakeview GS in 2005. Coal-fired generation at Nanticoke, Lambton, Atikokan and Thunder Bay will be removed from service by the end of 2007. This combined retirement scenario leads to a gap equal to approximately 1/3 of Ontario's existing low-cost supply by 2008.

3.3 Hydro

Currently, Hydro provides up to 8000 MW of capacity in Ontario. These are a combination of baseload hydro (2000MW) that is either low cost storage hydro, hydro that is run of the river and needs to be dispatched whenever it has generating capacity behind the dam, and peaking hydro which has higher embedded costs. New hydro projects will likely be bid into the Renewable Energy Request for Proposal released by the Ontario Ministry of Energy in June 2004. In addition, an expanded tunnel system at the Niagara Falls Adam Beck generating station will lead to an increase of 1.6TWh year from that generating station beginning in 2009.

The marginal cost for new hydro development in Ontario is estimated to be in the $70-80/MWh range. The key drivers for these costs are the extensive regulatory approvals that are required,

6 Ontario Power Generation (OPG) Review Committee, p 52.

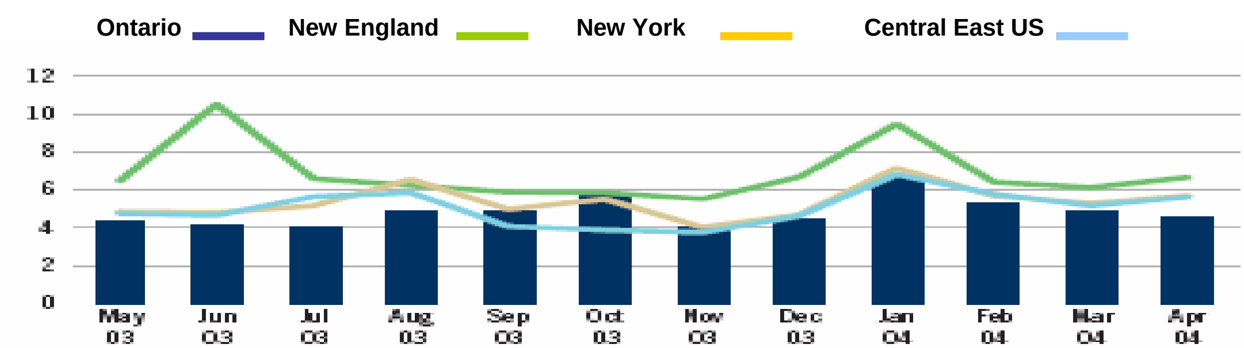
combined with the fact that only small hydro facilities are available in the province for development.[7]

3.4 Imports

The price of imported power is typically higher during peak times when demand is often outstripping Ontario-based supply. This creates a situation where the IMO (and thus industrial users) become price takers, rather than price makers when imports are not required (i.e. Ontario based supply is less than or equal to demand).

The impact of imported energy on prices was a key issue to consider in 2002 during the opening of the market in Ontario. However, Ontario's generation capacity improved significantly with the return to service of Bruce Power's Units 3 and 4, and Unit 4 at Ontario Power Generation's Pickering A station. As a result, reliance on imports to make up for shortfalls between the highest levels in demand and available domestic supplies was reduced.

Figure 3: Ontario Wholesale Prices vs. Neighbouring Jurisdictions (cents/KWh)



Source: IMO Market year in Review May 2003-April 2004

3.5 Renewables and Clean Energy

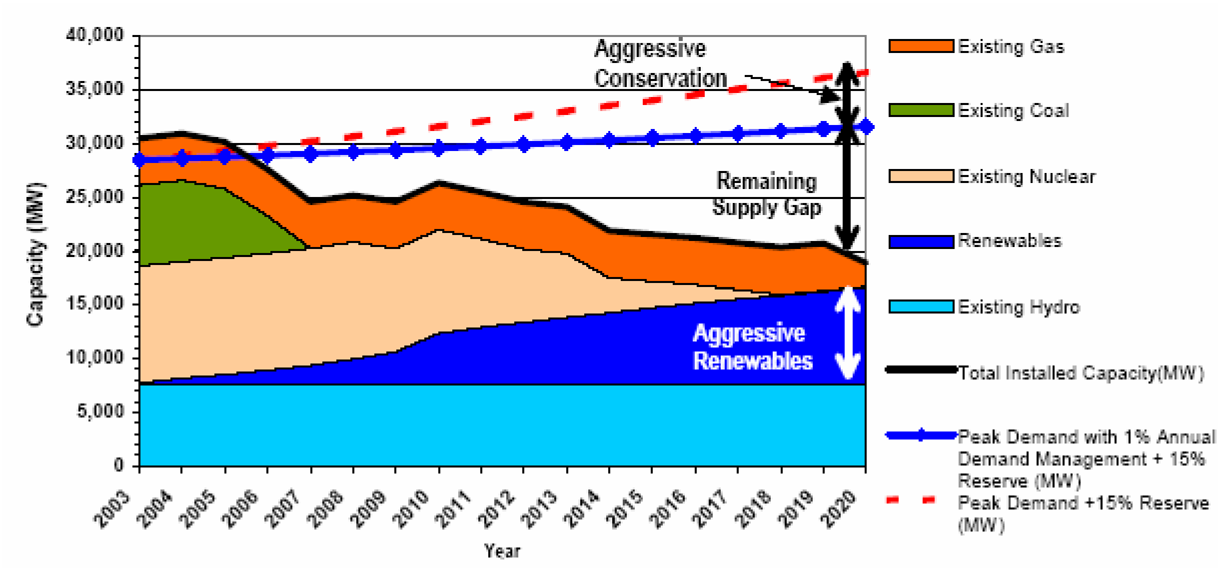
In 2004, renewable energy (excluding large hydro) represented less than 2% of supply in Ontario. The Ontario government recently released a Request for Proposals for 300 MW of renewable energy generation. No price guidance was given, other than the lowest price bids would be accepted first. In the interim, with no bid-prices available, a safe estimate of how expensive the energy will be is in the $70-80/MWh range. This price regime is based on the information regarding new hydro costs in Ontario, combined with price forecasts for wind energy in the province incorporated in the Pembina Institute Ontario electricity study released in 2004.

The figure on the following page illustrates how even with an aggressive renewables procurement strategy, the effect of shutting coal generating stations down will not be nullified.

7 Canadian Renewable Energy Corporation

Renewables will help supply baseload power over time; however a major gap between supply and demand will remain.

Figure 4: Generation vs. Peak Demand - With Renewables



Source: ECSTF, p51

In 2004, the Ontario government also released a request for proposals for 2500MW of clean energy or demand reduction supply. In service dates for energy bid in are June 2009. Demand reduction projects need to be in place by December 31, 2007. While this RFP may help alleviate a supply crunch in Ontario, it will likely not reduce prices significantly. The RFP states that *"…since the market has generally not provided sufficient net revenues to incent required new investment, this 2,500 MW RFP invites Proponents to submit a monthly amount, being the Net Revenue Requirement needed to cover these costs*".[8]

The government decided to take this approach to counter the price barrier that exists in Ontario's electricity market today. Specifically, the market framework and other supply-related factors have prevented prices from rising to a point that would create the conditions necessary to establish new clean energy generation or large demand-side management (DSM) initiatives. As a result, the government decided to tender this RFP in an open process. This will allow generators to bid in the prices they require to trigger private investment and establish new clean generation and/or DSM on line prior to the closing of the coal facilities. Based on preliminary assessments, prices for selected initiatives under this RFP are likely to be in the range of at least in the $60-70/MWh range.

3.6 Gas Fired Combined Cycle Gas Turbines (CCGT)

Until a few years ago natural gas appeared to the fuel of choice for the majority of proposed future clean and efficient electricity generation facilities. In fact, aside from refurbished nuclear,

[8] Ontario Ministry of Energy RFP for 2500MW of Clean generation and Demand side projects, p9 http://www.ontarioelectricityrfp.ca/2500MWRFP/Docs/RFP2500MW.pdf

new supply scheduled to be online by 2006 in Ontario, including the most recent Transalta Sarnia plant, is natural gas CCGT.

However, in recent years demand for natural gas has outstripped supply and prices have climbed accordingly. In addition, gas price volatility has been trending upwards for the past several years, making CCGT generators vulnerable to price spikes. This has been particularly true over the past few years in North America. Price shifts have been due to the limited ability of consumers to reduce their consumption in the short term, and of suppliers to increase short-term supply in situations where demand is high. A more detailed discussion around natural gas prices and their impact on gas-fired electricity generation costs is provided in Section 5.1.

Table 1: Gas Price and Price Volatility

Period of Time	Average 2003 price up 63% over 2002 ($US/MMBtu)	Price Volatility (standard deviation) [9]
2000 – 2003	$US 4.079	$US 1.64
1995 – 2000	$US 2.759	$US 1.20
1990 – 1995	$US 1.795	$US 0.41

Transalta Sarnia 575MW gas-fired generating station: The usage profile for this plant is a good example to estimate the future direction of prices in the electricity wholesale market. As recently as Transalta's 2004 Q2 results, this plant (completed in 2003) is only being used for 1/3 of its capabilities (450Mwh) because of the low HOEP. Further analysis shows that the plant is only selling 1/10th of its production to the Ontario market, with the rest going towards a long term contract. With coal setting the market clearing price for much of 2004 due to lower demand from more average weather conditions, Transalta's plant has not been financially successful.[10] Once coal is shutdown in Ontario however, it is expected that Transalta's Sarnia plant will be selling in to the market far more often.

Another plant, the Brighton Beach 625 MW gas plant in Windsor, commissioned in 2004 by ATCO Power and OPG is facing a similar situation.

3.7 Reserve Margins

In any electrical system, there are meant to be reserve margins which allow the system to withstand sudden increase in demand somewhere in the system. Typically, reserve margins have been set at around 18-24% of total supply. Recently, Ontario has been experiencing very low reserve margin rates. The IMO has provided some data for the past two years which demonstrate that at times there is actually a negative reserve margin of up to 10%. That is, Ontario is relying on imports and external markets to cover its reserve margin requirements. The IMO 10-year outlook shows the reserve margin ranges from the minus 10% to a positive 14% during peak times. At minus 10%, the gap in reserve margin is actually 28% using 18% as a minimum reserve margin level. Filling this gap essential to the safe operation of a grid, however, lacking of low-cost supply options expensive imported power or peaking plants would

9 Canadian Gas Association

10 See Transalta's Q4 plant production report at: https://www.transalta.com/website2001/tawebsite.nsf/9601eeb83bcdb335872568dc0062d915/ab899aa8efa8ae3487256ed8007a2f39/$FILE/TransAlta%20Production%20Schedule%20Q2-04%20IR.xls

need to be used. All market participants pay for this reserve margin in the rates they are charged by the IMO.

4.0 Structure of Ontario Energy Pricing

This section examines various aspects of the electricity price dynamic in Ontario including:

- An overview of the existing process to establish electricity prices in the province;
- A summary of average wholesale market prices and high price events, since the provincial electricity market opened up in spring 2002;
- A snapshot of daily variations in electricity demand and typical price fluctuations in an average summer and winter day.

4.1 Existing Pricing Process

Under the existing IMO structure, generators and importers of electricity review demand forecasts and determine how much electricity they can supply within a given hour and at what price. They send these "offers" to supply electricity into the IMO. The prices bid into the market are typically based on the cost of fuel and operations (fixed and variable costs) of participating suppliers.

The IMO then matches the offers to supply electricity against the forecasted demand. It first accepts the lowest priced offers and then "stacks" up the higher priced offers until enough electricity has been accepted to meet customer demands. All suppliers are then paid the market-clearing price, which is established every hour and is based on the last unit of energy bid into and accepted by the IMO. This is the price an industrial user then pays for its electricity for a given hour.

According to the IMO this "stacked" price approach encourages generators to keep their offer prices low in expectation of selling all or most of their potential energy output at the prevailing market price. This ensures the lowest possible price for users, while maintaining reliability of the system. Without the stacked market-clearing price, the overall result could be a much more volatile marketplace.

All low price electricity first goes to residential and small business customers covered by the set rates (approximately half of total demand during a typical day, or 12,000MW). Industrial and large commercial customers are totally exposed to the market clearing price and the higher priced electricity.

Industry Taking All the Risk

The split between the two existing rate-classes – industrial/commercial and residential/small business is approximately 50% of demand (or approximately 12,000 MW on a typical day). Residential and small business (below 250,000KWh/year) are charged 4.7 cents/KWh up to 750KWhs, and 5.5cents after that. Industrial/commercial rate payers are charged the hourly marginal clearing price, (MCP, or HOEP) set by the IMO thereby assuming all market risk.

4.2 Historical Wholesale Market Prices

The IMO releases annual snapshots of electricity prices, combined with projections of future supply, demand and price levels. Based on these reports, industrial users paid monthly averages of $52.30 to $57.60/MWh between May 2002 to August 2004. The highest monthly average market clearing price during this period of time was $88.60/MWh in February 2003, while the lowest was $41.90/MWh in November 2003. The average summer daytime time price during 2003 was $64.20/MWh. Average winter daytime price during 2003/4 was $71.20/MWh. [11]

Since the market opened, coal fired generation has been the effective price setting fuel over half the time. The average market price in Ontario when coal has been the last fuel dispatched has been about $34/MWh. In comparison to other fuels (see chart) coal is extremely low cost.

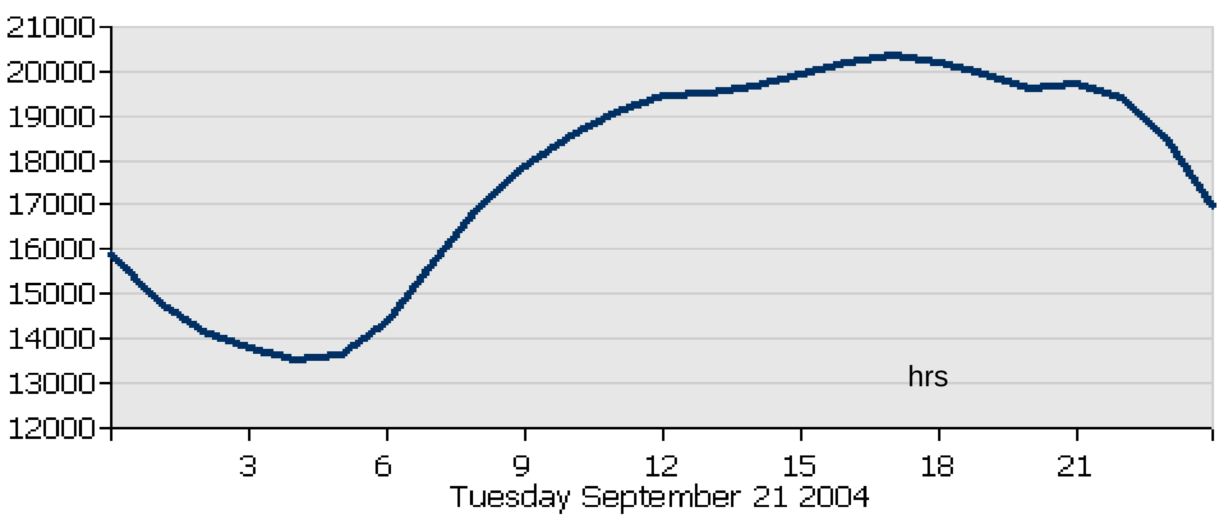
Table 2: Price Setting Fuel in Ontario (since market opening)

Price Setting Fuel in Ontario (since market opening)[12]		
Fuel Type	Price Setting Fuel (% of time)	Average Price ($/MWh)
Coal	56%	$33.8
Gas	8.3%	$66.4
Uranium	0.03%	$35 (est)
Water	15%	$76.7

4.3 Snapshot: Timing and Volume of Demand in Ontario

Typical electricity demand in Ontario follows a curve characterized by high usage in the day and low usage at night, as illustrated in the figure below. This standard demand curve was used as the basis for the price forecasting exercise outlined in Sections 6 and 7 of this report.

Figure 5: Hourly Ontario Demand in MW



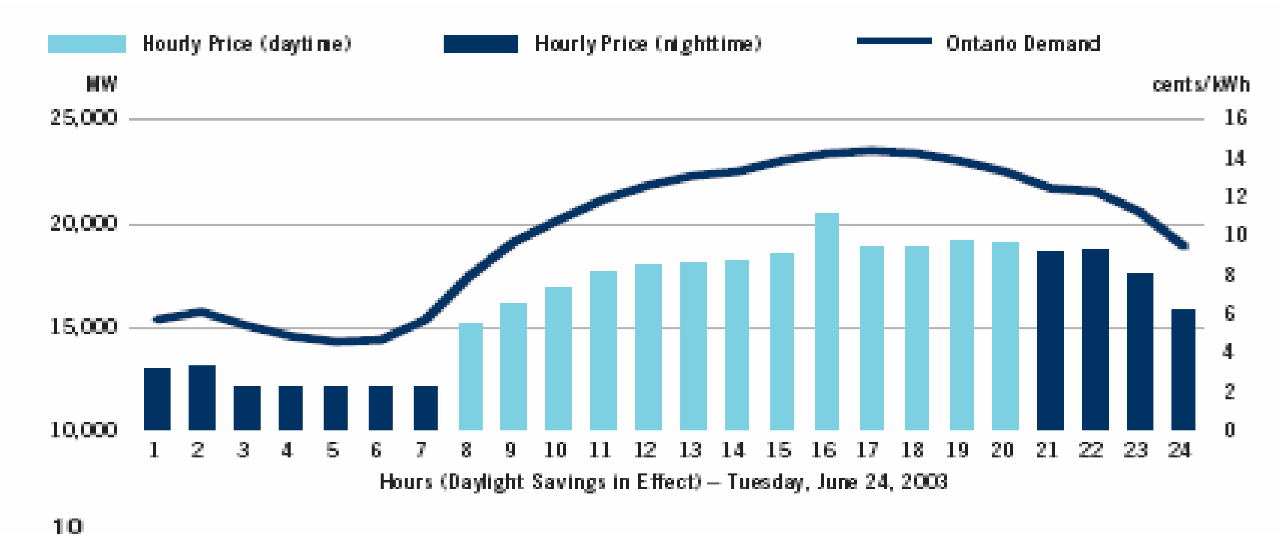
Source: IMO

[11] All price information available on the IMO website (www.iemo.com)
[12] ECSTF

4.4 Summer Price Picture:

The chart below provides an illustration of a typical summer day for the electricity markets in Ontario. During the hours of 6am and 10pm the price ranges from $60 to 100/MWh.

Figure 6: A typical Summer Day for Electricity Markets in Ontario

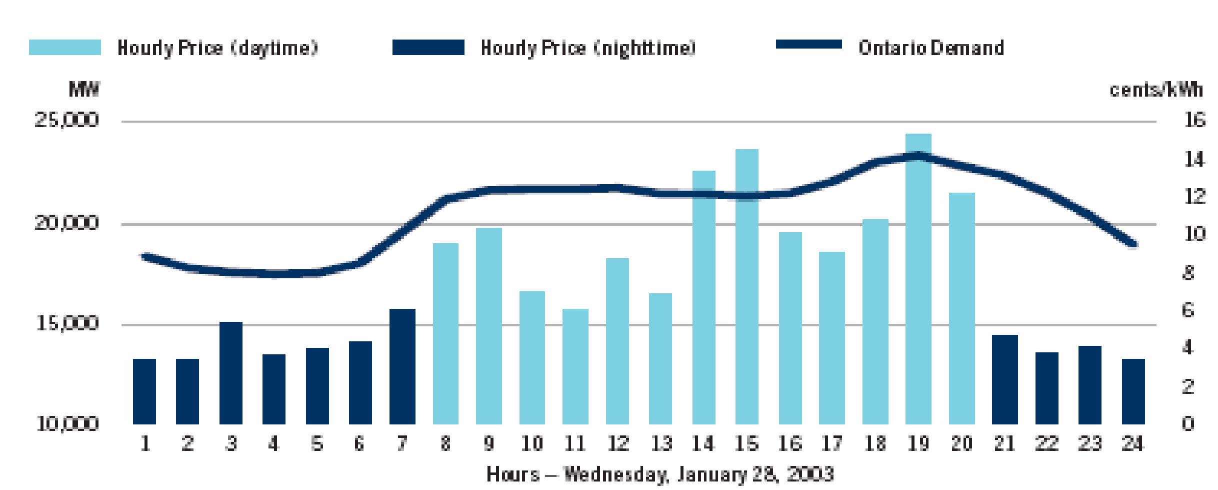


Source: IMO Market year in Review May 2003-April 2004

4.5 Winter Price Picture for Wholesale Markets

The chart below provides an illustration of a typical winter day for the electricity markets in Ontario. During the hours of 7am and 8pm the price ranges from $60 to 100/MWh.

Figure 7: Typical Winter Day for Electricity Markets in Ontario



Source: IMO Market year in Review May 2003-April 2004

4.6 Frequency of High Price Events

During May 2002 to April 2004, electricity prices in Ontario were considered high for approximately 36% of the time (or almost 9hrs out of each day). This breaks down as follows:

- The Hourly Ontario Electricity Price (HOEP) was above $200/MWh for 115 hours (0.7% of the time)
- The HOEP was between $60-80/MWh for 15% (2,628 hours) of the time, and
- The HOEP was between $80 and $120/MWh for10% of the time (1,752 hours).

This is an important consideration since the IMO produces regular price communications that refer to average daily prices, which tend to infer a much lower HOEP than what an industrial user would actually pay. This is because the average daily price quoted in these documents is simply an average of the 24 HOEPs within a given day. There is no weighting system applied to factor in the fluctuations in demand. Overnight prices when demand is low and when many industrial plants are dormant are given equal weighting to daytime HOEP's which tend to be much higher.

In reality an industrial user is likely to pay more than the quoted average daily price. Thus, the key average that is important for calculating costs is the average peak time price, particularly for those industrial and commercial customers using the majority of their electricity during the peak times of the day. It should also be noted that average prices noted in this section of the report were realized during a period of time when low cost coal fired generation provided up to a quarter of all electricity, and when high priced natural gas fired generation was only marginally relied upon. The future scenario, as discussed in the following section, reveals that these relatively low prices are likely to end.

5.0 5 Year Forecast of Electricity Prices

The section below provides a forecast of electricity prices in the Ontario wholesale market over the next five years. It is based on the supply and demand variables described in the previous sections.

5.1 Influencing Factors - Summary

The price of electricity in Ontario will be impacted by a variety of factors, including:

1. The reduction of Ontario-based generation, namely the phase-out of coal-fired plants and later nuclear facilities
2. Changing marginal fuel mixes with gas fired generation likely replacing a large portion of the baseload currently provided by coal, and renewables increasing their relative contribution to Ontario's supply mix
3. Rising cost of fuel oil and natural gas resulting from increased global demand and reduced supply
4. Time delays between calls for new energy in Ontario and actual supply from the selected new sources. Costs of these new energy supplies are likely to be higher as 'true' market

(i.e. with profit and without government subsidy) prices will be bid into the current and future calls for energy

5. Continued weakness in the US dollar increasing the relative price of oil. Global prices for oil are traded in $US per volume (different sized barrels). As such, a continued weakness in the US dollar is increasing the relative price of oil and gas, as buyers require more $US to purchase the same quantity of oil.
6. Continued security concerns, resulting in premiums being assigned to energy prices.

An exhaustive assessment of these critical factors impacting the supply and demand of electricity and the overall price of generation and transmission is beyond the scope of this report. However, this study focuses on the first three factors listed above which provide a conservative estimate of high probability. Specifically, it is recognized that without any major new base load capacity additions, or changes to the price-setting process, the phasing out of coal will lead to prices being determined by more expensive generating sources (i.e. gas-fired, renewables, and/or imports). This implies a price that is both higher and more volatile than previously. Recognizing the traditional role of natural gas for peaking supply in Ontario, under the most plausible of future scenarios, gas will evolve to become an intermediate energy source, setting the HOEP more often.

Taking this into consideration, Sections 6 and 7 will assess future daily price scenarios and the impact this will have on an industrial/commercial user in Ontario, over the next five years.

5.2 Assumed Supply Scenario

This study has chosen four well established assumptions regarding existing energy supply to consider as key determinants of the future price scenario for the next five years. The assumptions are as follows:

A. Coal fired generation at Lakeview Generating Station is shut down in 2005

B. Remaining coal fired generation is retired in 2007.

C. Nuclear is refurbished according to announced plans, at 50% more than the estimated cost.

D. Bruce A Unit 3 is removed from service beginning in 2009 (900 MW), and replaced with newer, higher priced renewables.

Assumptions regarding the pricing for various generating sources vary widely. For the purposes of this review the following ranges are used to estimate cost impact on industrial users:

Table 3: Future Price Estimates Used for Scenarios

Future price Estimates used for Scenarios	
Baseload Hydro	$30/MWh
Nuclear	$30-40/MWh
Coal	$35/MWh
Nuclear Refurbishment	$40-60/MWh
Gas/Oil/Peaking Hydro	$60-90/MWh

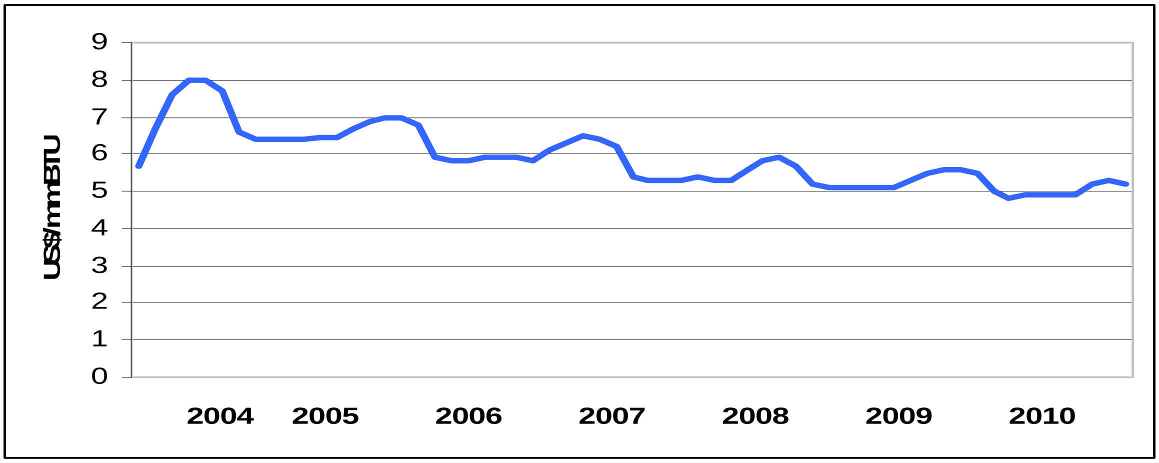
5.3 Future Natural Gas Generated Electricity Prices

While traditional supply is being reduced under the assumptions listed above, new supply is being generated from gas fired generation. Thus, it is important to understand what this effect will have on electricity prices.

Gas-fired generation price forecasts cited here are based on a number of sources, including the latest forecasts from the National Energy Board, the ECSTF, the OPG review report, BC Hydro's recent gas fired VIGP application, and the Pembina Institute's Ontario electricity report. All sources are from 2004 calendar year.

Although medium and long-term projections for gas prices vary, they tend to forecast natural gas prices that are below current price levels[13]. The Chart below represents the futures prices for natural gas on the New York mercantile exchange as of September 30th, 2004. These prices are a snapshot of what the future may hold for the costs of natural gas and CCGT electricity generation[14].

Figure 8: Future Prices of Natural Gas on the New York Mercantile Exchange



On the other hand, natural gas price volatility has been trending upwards for the past several years, as noted previously in Section 3.6. Below is a chart which illustrates how gas prices have been trending upwards in one of the key US trading markets, the Henry Hub. The extreme volatility associated with gas prices is also evident in this chart.

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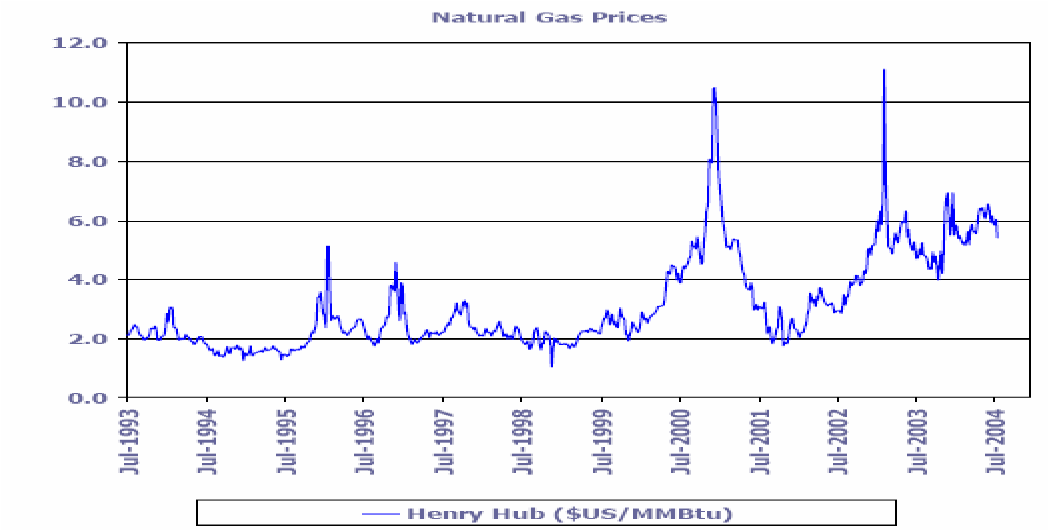
13 Pembina Institute: Power for the Future

14 To convert into Canadian dollars per GJ, multiply the US$ by approximately 1.26, and by 1.05 to get GJ from mmBTU.

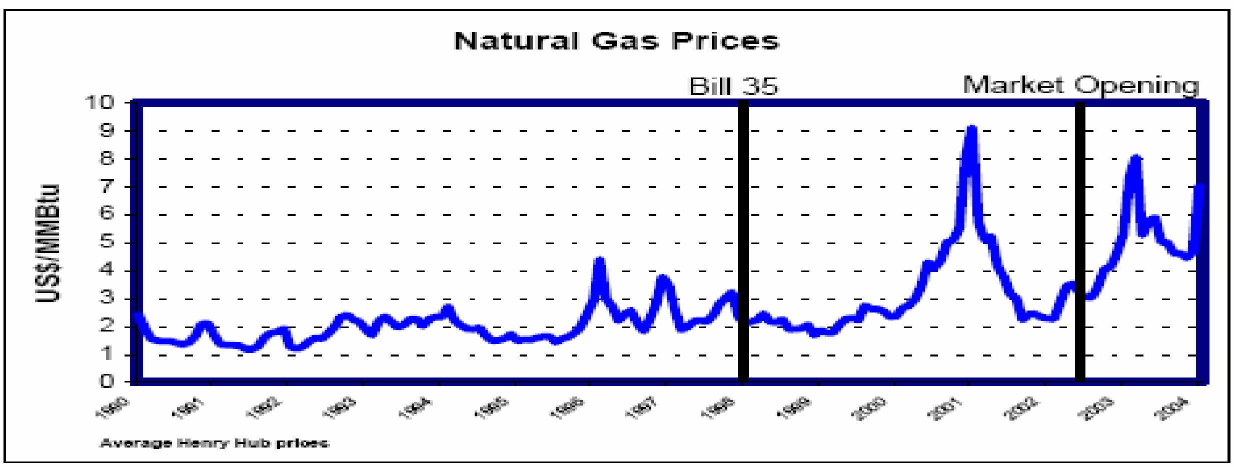
Figure 9: Natural Gas Prices in the Henry Hub Trading Market



Source: Canadian Gas Association

This upward trend is re-emphasized in the chart below which provides a picture of Ontario natural gas prices (in US$/MMBtu[15]) over the past 14 years. As in the US, gas prices in Ontario have been particularly high and volatile over the past several years.

Figure 10: Natural Gas Prices in Ontario



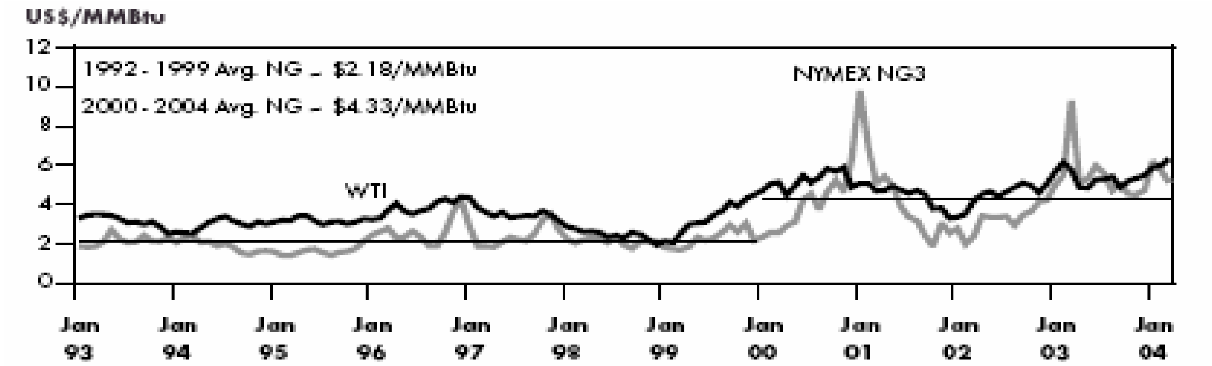
Source: ECSTF, p53

Energy markets are also more inter-related and the price of natural gas is increasingly influenced by the price of crude oil. Assuming that crude oil prices average in the range of US$24 to $35 per barrel, natural gas prices are likely to be in the range of US$4 to $6/MMBtu. North American imports of Liquefied natural gas (LNG), while increasing, are not expected to have a significant impact on natural gas prices within this timeframe as those volumes will be relatively small. Current (October 2004) oil prices are running in the $45-50 per barrel range suggesting that gas prices may continue to rise as well.

[15] 1 MMBtu = 1.05 Gigajoules ("GJ").

The natural gas price chart in Fig 11reinforces the trend towards higher gas prices that has taken place since approximately January 1999, as illustrated in a recent National Energy Board publication

Figure 11: Natural Gas Prices in Canada



Source: NEB – Canada's Energy Future: Scenarios for Supply and Demand to 2025 (July 2003)

These charts demonstrate the high degree of likelihood that gas prices will continue to rise into the future.

This upward trend in price and volatility has a significant impact on both current and future gas fired electricity generation prices. Overall generation costs for natural gas-fired plants are comprised of primarily four items:

1. Gas prices
2. Plant 'heat rates' (gigajoules of required gas per MWh output)
3. Operating costs (fixed and variable – non gas)
4. Capital costs.

The price of natural gas and the plant's overall efficiency are generally the key determinants of price per MWh, since fixed operating and capital costs are relatively low at CCGT plants. As an example, the following chart demonstrates the relationship between these variables with the following assumptions[16]:

- Capital Costs: $17.25/MWh
- Non-gas related Operating Costs: $3.71/MWh

Table 4: Gas Price and Heat Rate

Gas Price (CDN$/GJ)	Heat Rate (GJ/MWh)		
	8	7	6
5	$60.96/MWh	55.96	50.96
6	68.96	62.96	56.96
7	76.96	69.96	62.96
8	84.96	76.96	68.96

16 Figures taken from the Pembina Institute's *Power For the Future Ontario* Electricity Study, 2004, Appendix 4.

These numbers are fairly consistent with recent reports estimating the electricity generation costs for CCGT facilities. For example:

1. The recent OPG Review report (March 2004), estimated that CCGT electricity generation costs are in the $65-70/MWh.
2. The recent Pembina Institute 'Power the Future' report (July 2004) estimate CCGT production costs at $55-60/MWh.
3. IMO data from the past two years suggests that when gas fired generation is at the margin, the price ranges from $60-80/MWh.
4. A recent BC Hydro submission to the BC Utilities Commission for the construction of a CCGT plant assumed prices of $68/MWh, based on a gas price of $4.80CDN/GJ (heat rate for the plant was 7,308GJ/Gwh), or approximately $75 based on $6CDN/GJ. [17]

The Electricity Conservation and Supply Task Force in Ontario (ECSTF) did an analysis released in January 2004 of the impacts from having natural gas supply the majority of marginal electricity in response to lower supply of coal peaking power, and nuclear baseload power. The result was a price jump of $11/MWh, to $88/MWh (December 2002 gas prices). An alternate scenario which includes a combination of nuclear and new renewables fulfill peak load demand along side gas fired generation was also considered. The price remained high since gas remained the clearing price.

With these forecasts taken into consideration, the scenario presented here assumes that over the next 5 years the price of gas generation will between $60 and $90/MWh. There will be times where it greatly exceeds this range due to price spikes caused by the volatility which typically occurs in natural gas markets.

5.4 Key Rising Price Driver: Gas Replacing Coal

With coal being shut down, and other technologies and generation sources emerging afterwards, this review assumes the gas fired generation will be setting the market clearing price in Ontario far more often. The findings of the National Energy Board support this conclusion:

> The greatest uncertainty for the electric power generation sector is in the province of Ontario where the provincial government has announced plans to replace 7,500 MW of coal-fired generation. Natural gas demand growth for power generation as projected in the Board's report on *Canada's Energy Future* will remain largely unchanged to 2010 given the long lead times required for other fuels. Looking out beyond 2010, this sector will continue to consider alternative technologies and other fuels such as clean coal, renewables, hydro and nuclear energy.[18]

[17] Vancouver Island Generation Project: Application for Public Necessity and Convenience, p 82. http://bchydro.com/info/vigp/vigp4883.html

[18] National Energy Board: Looking Ahead to 2010 – Natural Gas Markets in Transition, p14 http://www.neb.gc.ca/energy/EnergyReports/EMAGasLookingAhead2010August2004_e.pdf

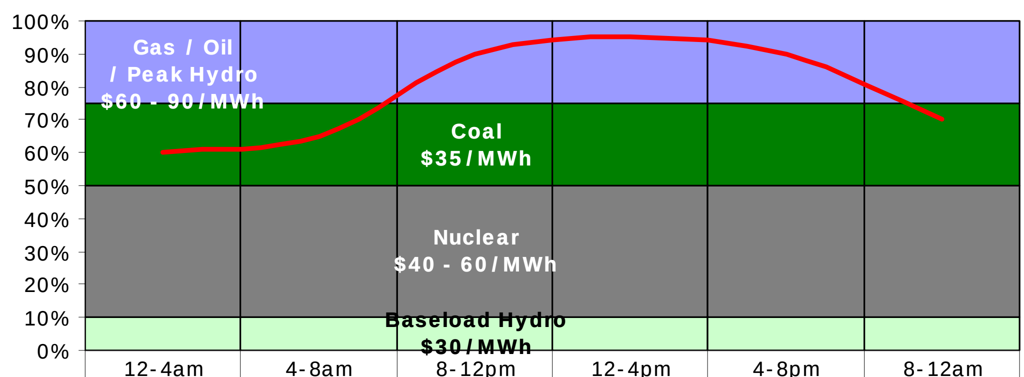
5.5 Illustrations of the Impact on Prices from Changes in Supply

The charts below are meant to be a snapshot of what a typical day might look like, under the various assumptions described above, for both price and fuel generation mix dispatching into the grid to meet demand. All prices are in 2004 dollars. The percentages on the right represent the amount of electricity supplied by the individual fuel sources coal, baseload hydro, nuclear or gas fired generation and other peaking fuels such as oil and particular hydro plants.

Demand patterns have been modelled using an aggregate of summer and winter daily demand trend lines. The trend lines on the following graphs (figures 12 to 16) show that the night demand is around 60% of peak. During the day, demand increases at a rapid rate between 6am and 10am. After 10am, until approximately 10pm, demand remains in a 'peak' zone at 90 to 95% of typical demand (max average around 22,000MW).

Baseline – The graph below shows the price regime along the demand line (usage %) no change in baseload supply or average price from the current picture in 2004.

Figure 12: Baseline

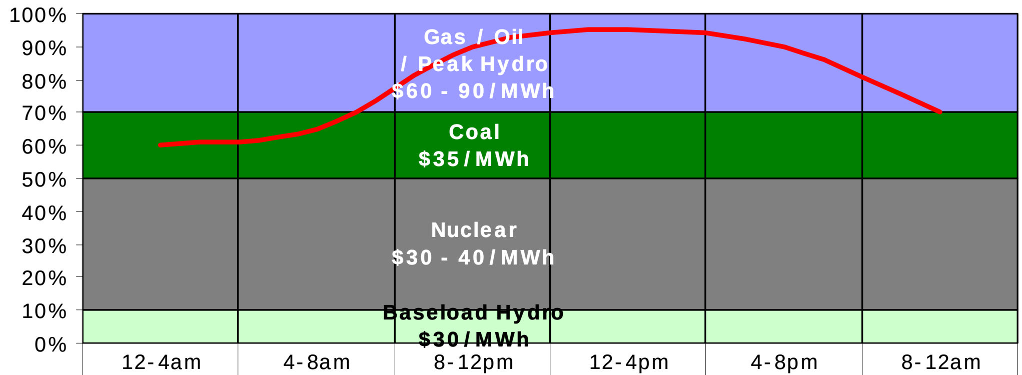


	12-4am	4-8am	8-12pm	12-4pm	4-8pm	8-12am
Gas/Oil/Peak Hydro	25	25	25	25	25	25
Coal	25	25	25	25	25	25
Nuclear	40	40	40	40	40	40
Baseload Hydro	10	10	10	10	10	10
% usage	60	65	90	95	90	70

In the base case, prices remain much as they have been over the past year and a half – averaging in the $50/MWh range, with price averages during peak time in the $60 and $70 range. Peak time at that price is limited to approximately 8 hours during the day.

Scenario A) Coal 2005 Shutdown: this graph shows what will likely occur in the market after Lakeview Coal Generating Station is shut down in 2005.

Figure 13: Coal 2005 Shutdown

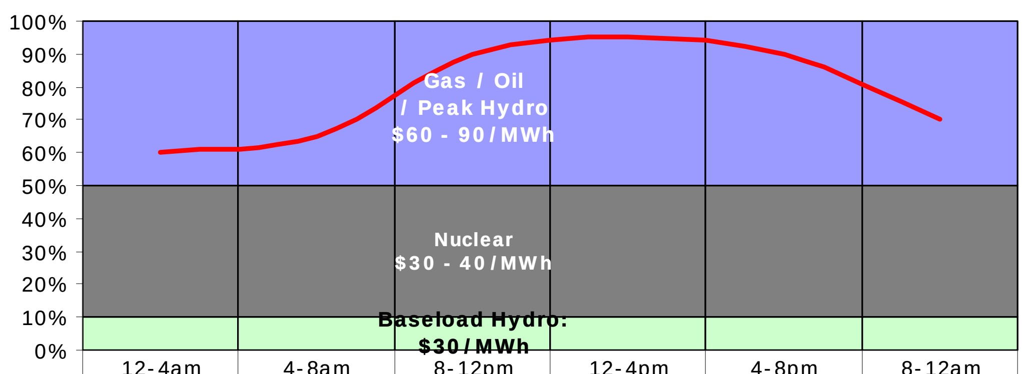


	12-4am	4-8am	8-12pm	12-4pm	4-8pm	8-12am
Gas/Oil/Peak Hydro	30	30	30	30	30	30
Coal	20	20	20	20	20	20
Nuclear	40	40	40	40	40	40
Baseload Hydro	10	10	10	10	10	10
% usage	60	65	90	95	90	70

The graph for this assumption demonstrates how the removal of Lakeview (1100MW) from generation leads to more supply from high priced gas. In particular, the market clearing price heads into high priced territory by about 7am, rather than closer to 8am in the baseline. At the end of the day, the MCP returns to lower priced coal, but not until well into the evening.

Scenario B) Coal Shutdown Assumption 100% by 2007: This graph demonstrates the different supply picture once all coal is removed from the system in 2007.

Figure 14: Coal Shutdown Assumption 100% by 2007

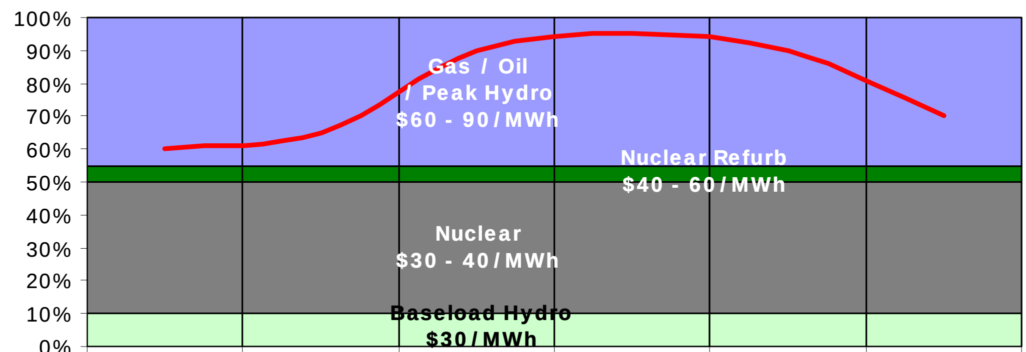


	12-4am	4-8am	8-12pm	12-4pm	4-8pm	8-12am
Gas/Oil/Peak Hydro	50	50	50	50	50	50
Coal	0	0	0	0	0	0
Nuclear	40	40	40	40	40	40
Baseload Hydro	10	10	10	10	10	10
% usage	60	65	90	95	90	70

With all coal fired generation shutdown, there is not enough baseload generation to cover even the minimum overnight needs. As a result, wholesale users would be paying in the $60-90/MWh range all day and night.

Scenario C) Nuclear Refurbished at 50% Increase in the Cost Estimate with Coal Shutdown: this graph depicts the additional supply from refurbished nuclear, however it delineates it in a different price point form the rest of the baseload nuclear.

Figure 15: Nuclear Refurbished at 50% Increase in the Cost Estimate with Coal Shutdown

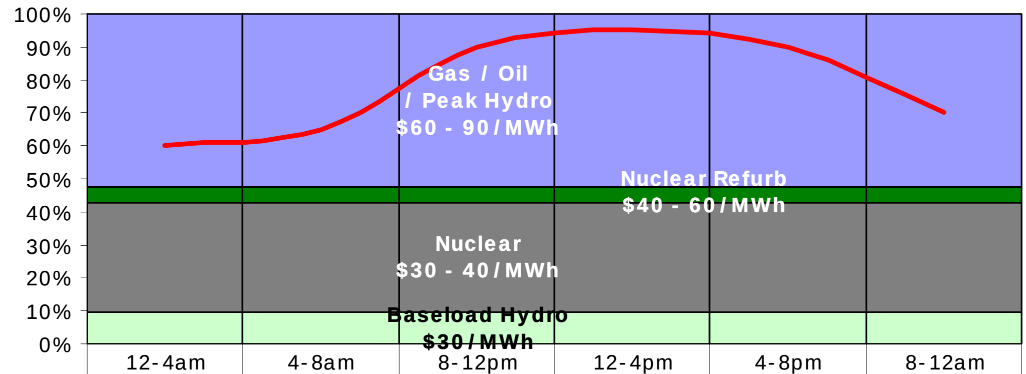


	12-4am	4-8am	8-12pm	12-4pm	4-8pm	8-12am
Gas/Oil/Peak Hydro	45	45	45	45	45	45
Nuclear Refurb	5	5	5	5	5	5
Nuclear	40	40	40	40	40	40
Baseload Hydro	10	10	10	10	10	10
% usage	60	65	90	95	90	70

Under this assumption, the more expensive refurbished nuclear does not have much impact on the HOEP since it is not sufficient to raise the baseload supply into even typical overnight low-demand levels. As a result, similar to the previous scenario, the price will most often be set by gas fired generation.

Scenario D) Nuclear – Bruce A Unit 3 shutdown as Scheduled in 2009: The removal of this Unit reduces baseload nuclear generation by approximately 5%.

Figure 16: Nuclear - Bruce A Unit 13 Shutdown as Scheduled in 2009



	12-4am	4-8am	8-12pm	12-4pm	4-8pm	8-12am
Gas/Oil/Peak Hydro	55	55	55	55	55	55
Nuclear Refurb	5	5	5	5	5	5
Nuclear	35	35	35	35	35	35
Baseload Hydro	10	10	10	10	10	10
% usage	60	65	90	95	90	70

Under this assumption the daily usage rate is significantly above all low-cost baseload generation. The shutdown of Bruce A Unit 3 removes approximately 5% of the nuclear capacity previously available. The 2009 timing is in line with the deadline for power to be online under the 2004 2500MW RFP, however the price of this power will likely be in the $60-90/MWh range as well.

5.6 Demand Growth & Demand Side Management – Moderate Determinants of Price

Between 2005 and 2010 the IMO estimates Ontario median demand increase will be 1.1% on average, and 1.3% for summer peak, or approximately 200-400MW a year. Over five years that represents new natural demand growth in the range of 1000-2000MW.

Demand Side Management (DSM) is not considered to be a significant factor in this review's assessment of Ontario electricity prices during 2005-10. The government recently released a request for proposals for 2500MW of clean energy and demand reduction measures. The demand reduction is required to be in effect by 2007, and the new clean energy by 2009. As a result, for the purposes of this review, we have assumed that DSM and natural demand growth virtually cancel each other out.

5.7 Mitigating Factors for the High Price Scenario

There are mitigating factors that may affect a scenario of higher electricity prices. Three of the most pertinent are gas prices, government policy changes regarding the coal shutdown and the ensuing public reaction to higher prices, plus changes to the design of the wholesale electricity market.

Government Policy Factors
As a policy response to an aggressive rise in wholesale electricity prices the Ontario government might delay the shutdown of the coal plants. The shutdown of Lakeview G.S. in 2005 appears to be underway and thus there is a high degree of probability that it will occur. The plan to close the other coal fired plants by 2007 is more 'at risk'. The government could decide to extend the timelines, delaying the loss of this supply while other sources of generation come on stream.

Alternatively, the government could continue with the shut-downs and be pressured to follow past practices and enact mitigating pricing policies often regarded as subsidies. However, for political and financial reasons further government subsidies in the electricity market are unlikely. If they are instituted, measures such as extending the existing Market Power Mitigation Rebate which is scheduled to end in spring 2006, or implementing similar price ceiling measures might be considered.

Market Structure Factors
A particular policy choice is the potential for reshaping the format for the wholesale electricity market in Ontario away from the current spot market. Under this scenario the wholesale market might revert to a tariff regime including levelized annual wholesale pricing, and/or time of day pricing.

Assuming this outcome, a brief analysis is presented below which illustrates the possible tariff rate for industrial customers replacing the current hourly spot pricing. The analysis is based on the simplest perspective that if all other factors are held constant, as low cost generation is removed from the pool, new generation with higher marginal costs exerts an upwards pressure on price. The bottom line is increased pricing based on the weighted average effects of changes in generation.

The scenario includes a conservative partial coal shutdown assumption, using the average wholesale price for the past year. In this scenario, there is no allowance for increased load demand, shut-downs of nuclear plants for repairs, or increased hydrocarbon costs, all of which are likely between now and 2009.

Key assumptions:

- Low end average monthly price: $52 for 12,500MW per day (industrial/commercial demand)
- 3,000 MW of coal removed (instead of 6000MW)
- 2,500 MW of new energy under the Clean Energy RFP @ $70/MWh
- 500 MW new energy under the Renewables RFP @ $70/MWh
- Remaining 9,500 MW of existing generation at a current representative average cost, $52/MWh

The outcome is a weighted average price that would be $57/MWh, a 10% increase from 2003/4 prices.

Price Volatility Factor
Price volatility resulting from the increased reliance on natural gas fired electricity generation could possibly mitigate moving to a tariff-based industrial rate structure because of political

considerations. Tariff-based industrial pricing may not be the most politically desirable approach since it involves a transfer of price volatility risk from industrial sector (1/2 the market currently and with all the volatility risk currently) either to the commercial/residential rate payer sector, or to the government as a backstop. Although speculation on future government action is difficult, if the electrical energy market continues trending toward more connection to hydrocarbon prices, it is likely the government would enact measures to insulate commercial/residential rate payers from the resulting impacts, and likely would continue to expect the industrial sector to deal with the volatility. Instituting industrial rate tariffs would in effect ask residential/commercial rate payers to bear the burden of more price volatility, which has proven to be politically difficult in Ontario and elsewhere.[19] This is the dilemma the current government faces in contemplating restructuring the existing hourly spot market.

Gas Price Factors

Gas prices may not continue on an upward trend line as has been predicted. Currently the NYMEX futures suggest a price of between US$5 and US$8/mmBTU for the next five years. On average this is much higher than the previous five years. Two key factors could reduce prices: 1/lower demand or 2/higher supply. Demand might soften due to several factors including an economic recession, or very warm winters and cool summers. New supply is currently scheduled to come from two major sources, the Mackenzie Valley pipeline in Canada, and new liquefied natural gas facilities. These supply options involve significant infrastructure investments, and are arguably years away from having an impact on gas prices.[20]

A brief analysis follows which contemplates the effect on electricity pricing should gas prices move significantly downward. If gas prices return to levels experienced during the mid nineties (US$2-3/mmBTU), gas fired generation costs would be reduced accordingly. At US$3/mmBTU, gas fired generation would be priced at approximately $45-55/Mwh. This would reduce the price of peak power (or baseload with the coal removed from service) provided by gas. It would also likely lead to a greater reliance on gas fired generation and less resistance to shutting down the coal plants. Thus, despite the lower cost for gas, it would be relied upon to replace $35/MWh coal. At $45/MWh plus $18/MWh in transaction costs, an industrial customer would continue to pay a higher price than is currently the case. Price increases for the wholesale market would still occur, however with lower overall impact than under the higher gas price scenario used for this report.

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[19] The Alberta government has repeatedly insulated residential electricity consumers from the volatility of the wholesale electricity market since its was deregulated in that province.
[20] Canadian Gas Association

5.8 Forecast of Prices

As a result of the changes in supply dynamics under the scenarios presented above, prices would change significantly for industrial users. In the chart below daily weighted average prices are given which reflect the number of hours the wholesale market is in the high price area vs. the low price area.

For the high price hours, an average of $75/MWh is used to reflect the average of the $60 to $90/MWh forecasts for gas price generation costs.

According to the Figures in section 5.5, the pricing will look as follows:

Year	Weighted Average Price	Explanation
2005	$53/MWh	Base Case: Reflects the prices experienced over the last year. 50% of the time prices are in the $35 range, and in the $70 range the other half of the day.
2006	$57/MWh	Scenario A: Lakeview Coal plant is shut down removing 20% of the coal generation. 38% (9hrs) of the day the HOEP is in the low price range, and 62% of the time it is set by higher priced gas generation and peaking plants.
2007	$75/MWh	Scenario B: The rest of the Coal is shut down. The HOEP is in the high price range 100% of the time. Average price is thus set somewhere in the $60 to $90 range. Even over night, during off peak hours there in not enough low cost capacity to move prices into the lower levels set by the nuclear generating stations.
2008	$72/MWh	Scenario C: Nuclear refurbishment leads to an additional 5% of supply coming from Pickering generating station. As a result, the demand line is closer in the illustration to lower priced generation. While the demand line remains in the higher priced category of supply, it is in the lower end of that range for more hours than in Scenario B. The distribution is approximately 40% of the time at $60/MWh, 40% at $75/MWh and 20% at 90/MWh.
2009	$75/MWh.	Scenario D: Bruce A Unit 3 shutdown as scheduled, removing 5% of the low cost nuclear generation from available resources. This returns the market back to a similar situation as Scenario B, when all the coal is removed. Average price would increase again to $75/MWh.

By 2010 most of the tendered generation projects under the two RFPs released by the government in 2004 would be creating or saving approximately 3000MW of electricity. Demand growth would have added approximately 1000-2000MW to the requirements. Supply will remain tight, with prices reflecting this imbalance in the electricity market.

6.0 Cost Implications for a Proxy Industrial User

A proxy industrial user consuming 90,000MWh per year (~10MW demand per hour) and operating their facility for 24 hours per day was employed to illustrate the implications of increased electricity prices on an industrial user.

This type of user would be fully exposed to gas fired generation prices under all scenarios except Scenario A - coal shutdown in 2005. The industrial user relying on the wholesale market would be paying the market clearing price for gas-fired generation almost 100% of the time under this scenario after 2007. In between the 2005-7 years, with just the one coal plant shut, the price is set by gas-fired generation approximately 2 hours earlier than under the base case.

Below is a chart which shows the cost implications from four price ranges for electricity consumption levels with 100% of demand falling in the high priced range, medium range and lower base case range. When Ontario Hydro debt, IMO, Distribution company and transmission charges are added the price increases by at least $18/MWh (Debt and IMO charges alone are approximately $13/MWh).

The chart below uses the $52/MWh average industrial price for 2003/4, the $57/MWh for the low end based on the discussion in 6.4., the $75/MWh high cost average price, and the $90/MWh high gas price/gas fired generation upper end scenario.

Table 5: Cost Implications for Present day, and Future Low and High Price Range for Electricity Consumption

	Annual Cost implications @ 90,000 MWh/year.
100%of consumption at $52/MWh plus charges $70/MWh	$6,300,000
100%of consumption at $57/MWh plus charges $75/MWh.	$6,750,000
100% of consumption at $75/MWh plus charges: $93/MWh.	$8,370,000
100% of consumption at $90/MWh plus charges: $108/MWh	$9,720,000

All figures in 2004 dollars.

7.0 Conclusion

Currently in Ontario there are several key drivers of higher electricity prices that are seen to be converging. Firstly, there are major supply reduction measures in the Ontario electricity market which are on the verge of occurring. These are combined with a time delay for the new requests for additional private sector energy supply under tender calls from the Ontario government, plus the reality that these new supplies will be more expensive then much of the electricity being supplied today. These factors led this analysis to conclude that the wholesale electricity markets in Ontario will experience significant increases in prices over the next five years. .

The analysis demonstrated that in the near future, and potentially beyond 2010, Ontario will rely increasingly on natural gas fired generation for more than 70-80% of its peak time capacity. Factoring in estimates of continued gas price increases over the next few years leads to the conclusion that industrial and commercial energy users may be paying approximately 50% more for their electricity than they have been. Cost increases modelled in Section 7 suggest that for a proxy user consuming 90,000MWh per year, $1-3 million might be added to their annual power bill.

With gas fired generation providing increasing amounts of electricity, the Ontario government undoubtedly will be under pressure with regards to high electricity prices. As a result, some policy measures may be taken in the future to alleviate this situation. These could include changes to the wholesale electricity market design, or extending the phase-out plans for the coal generation. However, with increasing debt levels from the nuclear fleet of generators already being paid off by a specific tariff all electricity users pay, it is unlikely the government will be in a position to subsidize Ontario electricity market any further. Additionally, should some of the existing coal fired generation slated for shut downs be left running, all the new electricity coming in under the current government electricity tenders will have higher marginal cost, and will be supplying greater proportions of baseload power. Thus, at a slightly later date, average price would continue to move higher.

Alternatively, gas prices could be lower than forecasted. However, this outcome would have the likely impact of removing the price related pressure on the government to leave the coal generation in place. Gas would be relied upon for significant amounts of baseload power, thus increasing the wholesale price since even a low cost gas generation is more expensive than the current rate for generating electricity from coal.

For the reasons summarised above, this review concludes that industrial electricity customers in Ontario are likely to face higher electricity costs over the next five years.

Appendix A: Green Valuation

Green Valuation refers to the financial value that can be generated by environmental credits associated with renewable low impact energy. In particular, this section reviews two types of environmental credits, namely emission credits and 'green tags'.

Emissions credits: Two types of emission credits are emerging that apply against renewable energy projects and help increase cash flow: Kyoto emission credits and Ontario emissions trading credits.

Kyoto Credits: The federal government's industrial regulations under the Kyoto Protocol will include a provision whereby a renewable energy developer will earn 'emission credits' for its renewable energy generation in recognition of the greenhouse gas emissions it avoids or displaces in the electricity system. The plan as drafted would award a credit on a per tonne basis per unit of output from a turbine, or generating station. The level of emissions credit is still under debate, however it would work in the following manner: for every MWh of production, the government would automatically assign an emission credit at some level per MWh, say .02 tonnes. The tonnage figure is an estimation of the emissions the renewable energy project is avoiding or displacing somewhere in the electricity grid. This is a very uncertain estimate, and needs to be set as a proxy. It is extremely problematic attempting to determine exactly what emissions are affected by a particular renewable energy project. However, more likely than not it has made a difference and in recognition of this fact the government has chosen to assign such production an emissions credit.

The question remains however, as to the value of the credits worth to the owner of a renewable energy generation system. This will depend on another market, the emissions trading market. Emissions will be traded on a per tonne of carbon dioxide equivalent (CO_2e) basis, and will likely be priced somewhere in the $3 to $20 per tonne range[21]. The emissions trading market is in its infancy, however trades do take place. As the government in Canada assigns emission targets to large emitters, the market will function with more liquidity as an increase in participants get involved. Additionally, GHG emission markets are already functioning in the US and Europe. With the anticipated entry into force of the Kyoto Protocol, the emissions trading markets are anticipated to become much more active between 2005 and 2012, the end of Kyoto's first emission reduction target period.

To understand what this means to cash flow as a power customer that obtains credits, one needs to make the assumption around the price that will be paid on the open market for a credit equal to the reduction of one tonne of CO_2e, along with the quantity reductions (tonnes of CO_2e) that are associated with each MWh of renewable generation. For example, if the value of credits (or price per tonne) is $10 and each MWh generated by the subject renewable facility offsets (i.e. reduces) 0.03 tonnes of CO_2e, then the power customer will generate supplementary revenue equivalent to $3/MWh.

Ontario Emissions Trading System: An emissions trading system exists in Ontario which rewards particular sources for avoiding nitric oxide (NO) and sulphur dioxide, SO_2 emissions in the electricity system. Renewable energy is eligible for earning emission credits. These credits are allocated in a similar manner as the proposed Kyoto system, at a predetermined rate per MWh. They then can be sold to entities in Ontario covered by an emissions target. Currently the largest player in this market is Ontario Power Generation, and only limited trading is occurring.

[21] Prices sourced from Pointcarbon.com, www.evomarkets.com, and prototypecarbonfund.org.

However, the Ontario government has announced an extension of their emissions trading system to include caps for facilities outside the electricity sector. This may lead to increased demand for renewable energy generated emission credits, thus increasing their financial value to generation owners. In addition, emissions trading systems for NO, SO_2 which encompass renewable energy, already exist in much of the US.

Green Tags: Could be awarded to renewable energy generation under a renewable portfolio standard, or feed-in tariffs.

Renewable Portfolio Standards: Green Tags: In some jurisdictions, governments assign electric utilities a target for acquiring renewable energy generation. In those systems, utilities are often given several choices for meeting their targets, they can contract for the renewable energy generation that is required of them, or alternatively they can purchase 'green tags' from a third party. Those green tags represent 1 MWh of renewable energy that has been fed into the grid at regular electricity prices. It has a higher intrinsic value, which is captured in the tag. Ontario has a renewable portfolio standard, however they have not assigned it to distribution utilities, nor have they opted for a tag approach. Instead they are setting out request for proposals for renewable energy to meet a particular target. However neighbouring jurisdictions do have green tag systems, including a recently announced New York State RPS. In other jurisdictions, green tag systems have provided a $5-50/MWh premium to renewable energy projects.

Renewable Energy Feed-In Tariffs: Another approach to encouraging renewable energy development is to assign particular technologies automatic premiums. Different premium levels are set-out for different technologies, depending on their economics. Depending on the jurisdiction, a suite of energy –types will be selected. For instance, the various forms of solar energy production will be assigned various levels of tariffs. The tariffs are set at a certain price per MWh, which is paid on top of the market price to the generator. This premium is meant to allow technology to have a reasonable rate of return; at least enough to compete against more conventional energy production types. Ontario does not currently have a system of tariffs in place. However, neighbouring jurisdictions in the US North East are well advanced in with regards to their development. Feed in tariffs have a similar range as prices do in green tag trading systems ($5-50/MWh). The key difference is that the generator knows ahead of development how much premium their production will be assigned.

All of these options provide an additional financial signal to renewable energy developers. They vary in methodology, however they are striving for the same goal, to monetize the environmental benefits society receives from renewable energy generation. It is highly likely the renewable energy development in Ontario will benefit from at least one of these systems within several years.

Examples in other jurisdictions of existing REC market, emissions trading or tariff systems.

Texas REC prices on 09/22/04

term	bid price (change)		offer price (change)		last price (change)		Date	actions
2002	$10.00	n/c	$14.00	n/c	$11.00	n/c	8/23/04	
2003	$12.00	n/c	$13.00	n/c	$11.50	n/c	9/09/04	
2004	$12.25	n/c	$13.50	n/c	$12.50	n/c	9/15/04	

Massachusetts New REC prices on 09/22/04

term	bid price (change)		offer price (change)		last price (change)		date	Actions
Q4'03	$42.00	n/c	$50.00	n/c	$45.50	n/c	06/11/04	
Q1'04	$47.00	n/c	$50.00	n/c	$48.28	n/c	6/22/04	
Cal'04	$47.00	n/c	$51.40	n/c	$49.25	n/c	7/19/04	
Cal'05	$40.00	n/c	$47.00	n/c	$46.00	n/c	9/02/04	

Source: Evolution Markets (evomarkets.com)

GHG Emission Markets

EU Markets on 09/23/04

spec	term	volume	bid price	ask price	volume	
EUA	2005	10,000	€ 8.80	€ 8.85	10,000	
EUA	2006	5,000	€ 8.80	€ 9.00	5,000	
EUA	2007	5,000	€ 8.90	€ 9.10	5,000	

UK Markets on 09/23/04

spec	term	volume	bid price	ask price	volume	
UKA	2005	1,000	£ 3.50	£ 4.00	5,000	

Kyoto Markets on 09/23/04

spec	term	volume	bid price	ask price	volume	
CER	2005	100k	€ 5.00	€ 7.00	100k	

Source: Evolution Markets

SO_2 Emissions trading market in the US.

DATE	SPEC	TERM	BID	OFFER	LAST
22 Sep	**SO2**	**2004**	$495.00	$505.00	$505.00
22 Sep	**SO2**	**2005**	$494.00	$504.00	$504.00
22 Sep	**SO2**	**2006**	$490.00	$500.00	$500.00

Source: Evolution Markets

Appendix B: Methodological Note

The analysis for this review relied specifically on five key Ontario electricity reports that were released publicly in 2004. They are listed in the 'Key References' section below. Each of those reports provide an in depth consideration of the current and future electricity supply and demand situation in Ontario. This Ontario electricity price review relied on the data in those five reports to build a future price scenario. All government policy announcements, in particular those regarding coal generation shut downs, hydroelectric investments and nuclear refurbishments were taken as fact. The emphasis for this review was to look at factors which would cause upwards pressure on electricity prices in Ontario, of which there are many. It should be noted that no interviews were conducted with key government electricity policy officials for this analysis.

Key References

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Other References

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Canadian Gas Association. Gas price information can be found on their website at: www.cga.ca/pdfs/Market%20Update%20English%20June%202004.pdf

Canadian Renewable Energy Corporation. Company website: www.crec.ca

Evolution markets. Website: www.evomarkets.com

New York Mercantile Exchange. Gas price futures can be found on their website at: www.nymex.com/jsp/markets/ng_fut_cso.jsp

National Energy Board (NEB). Website: www.neb.gc.ca

Ontario Ministry of Energy, Renewable Energy and Clean Energy Request for Proposals. Website: www.ontarioelectricityrfp.ca

Transalta Corporation. Company website: www.transalta.com