Electricity Price Forecasts for St. Lawrence Hydroelectric Generation

Final Report

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Introduction

The purpose of this study is to develop estimated prices for the electricity generated by the Moses/Saunders and Beauharnois/Cedars hydroelectric stations on the St. Lawrence to help inform decisions about the regulation and operation of that shared water body.

The starting basis that we are using for those estimated prices are those in the current wholesale electricity markets. Such competitive markets are a fairly recent innovation. The New York market has been in operation for about 4 ½ years, and the Ontario market for slightly more than 2 years. Our experience to date shows that the clearing prices in these markets and related forward prices are useful indicators of the value of generation, but that this market data needs to be combined with other information. This is partly because these markets are still evolving and the form they will take, or whether they will still exist, thirty years from now is not readily predictable. Furthermore these markets may not always operate in an economically efficient manner because of the exercise of market power or flaws in their design.

Another characteristic of today's electricity markets is that there are multiple and interrelated products. Some of the electricity products include: energy (both day-ahead and real-time), reserves (spinning and quick start), regulation, transmission, and capacity. In addition, some of the markets for these products are further segmented on a locational basis. A given generator may participate in a number of these markets. The markets are also interrelated to an extent that changes in one may affect another. These interrelationships must be considered in formulating price projections.

With those caveats in mind, we will start with the current markets that we have and use them as the basis for developing future electricity prices.

This document and its associated files are provided to meet the following requirements:

1. *Review hourly real-time wholesale electricity market clearing price data for the New York and Ontario markets, and the regulated wholesale electricity price/replacement-cost assumption in use in Quebec, i.e., $87 Canadian/MWh.*
2. *Over these markets' period of record, considering factors such as market conditions, scheduled and unscheduled outages, economic growth, weather and any other key market and public policy/regulatory drivers, prepare short-term (i.e., two years) wholesale electricity price forecasts for each of the three markets, each for a 48-quarter-month time-period. Insofar as these prices will be used in the calculation of social benefits, with respect to the Beauharnois and Cedars GS, consider the appropriateness of using a single, regulated price, and the assumed replacement cost, and if justifiable, use alternative prices/replacement costs. Relative to price-variations observed in hourly market clearing prices, consider the effect of using an hourly versus quarter-monthly time-step on the accuracy of estimating these benefits.*
3. *For the New York and Ontario markets, review the assumptions associated with the estimated benefit derived from daily peaking operations at the Moses-Saunders GS, and prepare a second of price forecasts that account for these incremental benefits.*
4. *In preparing these forecasts, consider the importance of seasonal cyclicality in prices relative to price levels as it relates to the potential for generating new benefits through the inter-seasonal banking of water.*
5. *Characterize the uncertainty associated with these price-forecasts.*

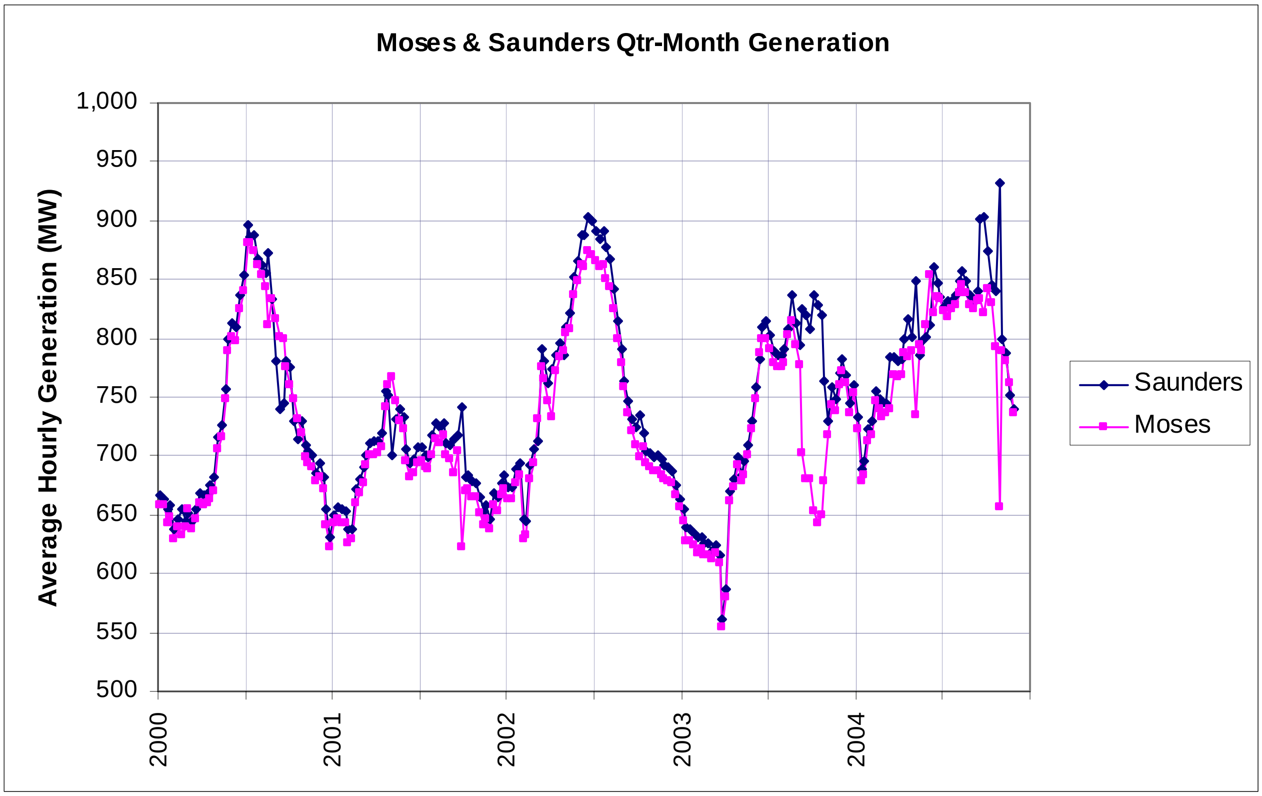
6. *Considering the factors in Task 2, as well as other key market and public policy/regulatory drivers (e.g., replacement-cost assumptions), prepare a range of likely (e.g., high, medium, low) price-forecasts for these markets using a 30-year horizon.*
7. *To help clarify some of the secondary effects of alternative regulation plans, characterize the emissions impacts (e.g., CO_2) that could reasonably be expected to result from varying levels of hydropower production, and the impacts associated with shifting production inter-seasonally.*

Historical Information

To gain some understanding of how hydroelectric facilities operate on the St. Lawrence and to better understand the economics and physical aspects of those facilities, we analyzed the available historic data.

We first examined the historic generation patterns for those generators. The chart below shows the quarter-monthly[1] average hourly generation for the Moses and Saunders stations since January of 2000. The first thing to note is that the pattern of generation over time, at the quarter-monthly level, is very much the same for the two stations as one would expect based on a common water flow. There are a few exceptional periods with major dips in Moses' generation; we believe these departures are associated with maintenance or replacement operations. For the years 2000 through 2003, there is a fairly typical annual pattern—generation levels are at their lowest in the winter, with peak generation in the late spring and early summer. The occasional deep dips are probably because of equipment maintenance. The magnitude of the summer peaks do, however, differ from year to year. The pattern for 2004 is however somewhat unusual in that the peak is less pronounced and extends later into the summer. The most likely explanation for this was that 2004 was a cool wet summer and water flows were greater than average.

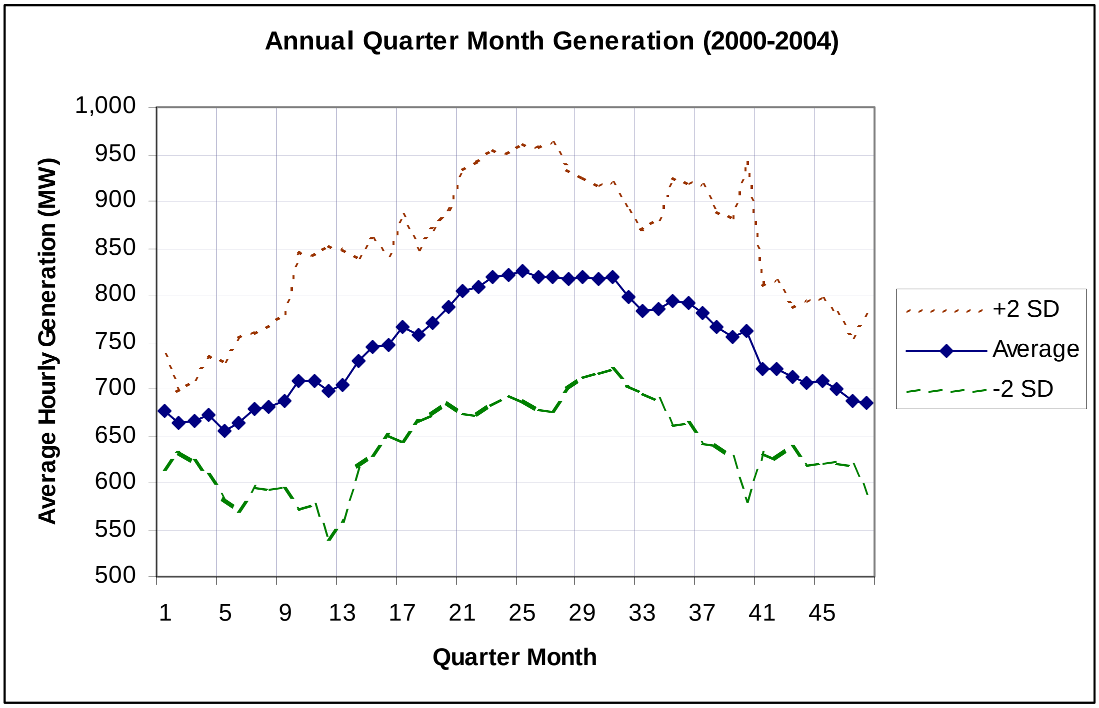
Figure 1: Moses & Saunders Quarter-Month Generation



[1] Quarter Months are time units used in the management of the St. Lawrence. Each month is split into four periods of days. For 30 and 31 day months, the groupings are as follows: 1-8, 9-15, 16-23 and 24-30(31).

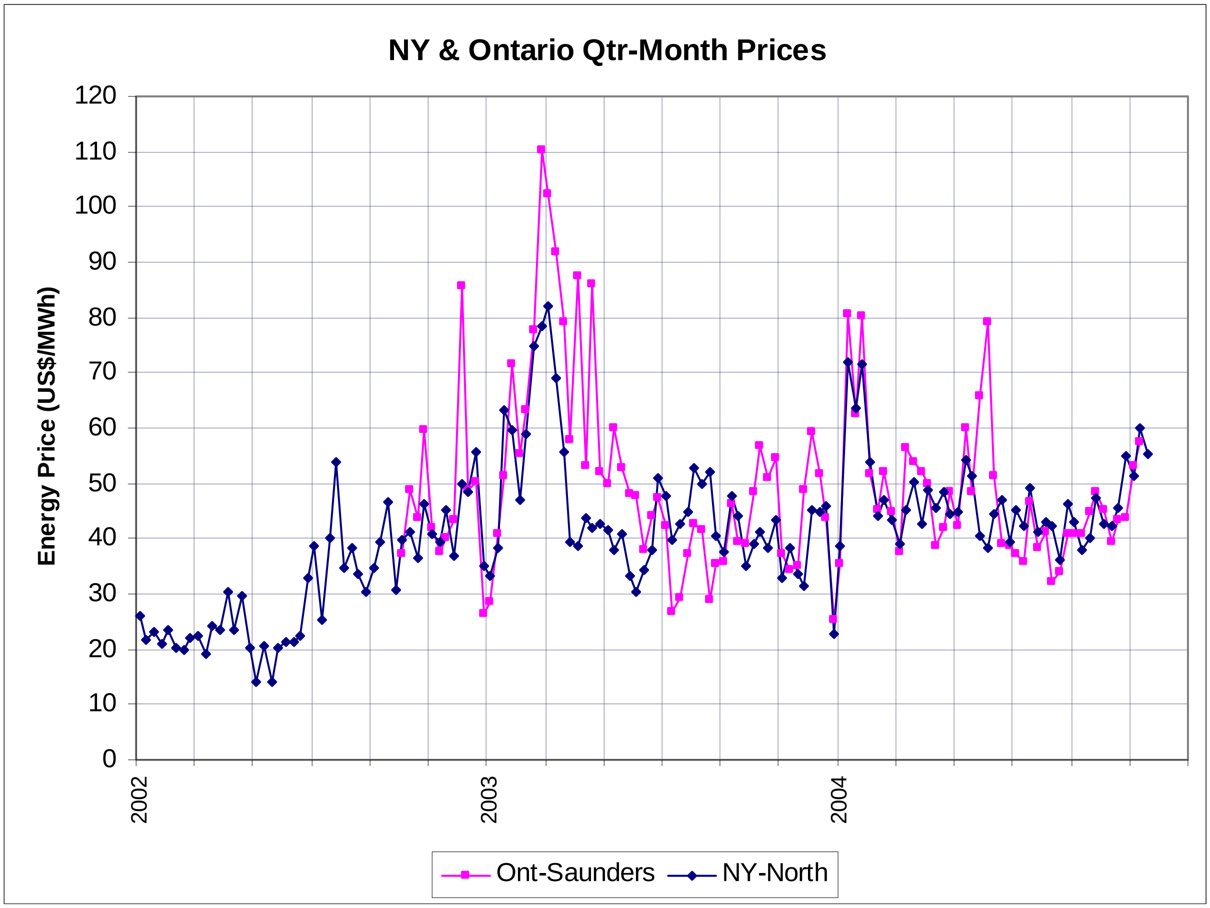
To get a better understanding of the basic annual generation pattern, we then calculated the quarter-month averages and standard deviations (after excluding the anomalous low value periods shown above). Here the seasonal pattern is quite clear. The annual average hourly generation level is 746 MW, with the average for the lowest month of January being 670 MW and for the highest month of July being 820 MW, which respectively are 9% below and 10% above the annual average. However there are substantial variations year to year in the quarter-month generation as indicated by boundary lines at plus and minus two standard deviations. This basically reflects the year to year differences as shown in the previous figure.

Figure 2: Annual Pattern of Quarter-Month Generation



For energy prices, the available time series data is much shorter with just two years of data for Ontario. It is worth noting that for 2003 the peak price was in late February, and for 2004 the peak price was in January. Except for June of 2004 in Ontario there is no summer price peak. After adjusting for currency exchange rates, the initial Ontario prices in 2003 were above those for New York, but for the last year and a half they have settled at very similar levels.

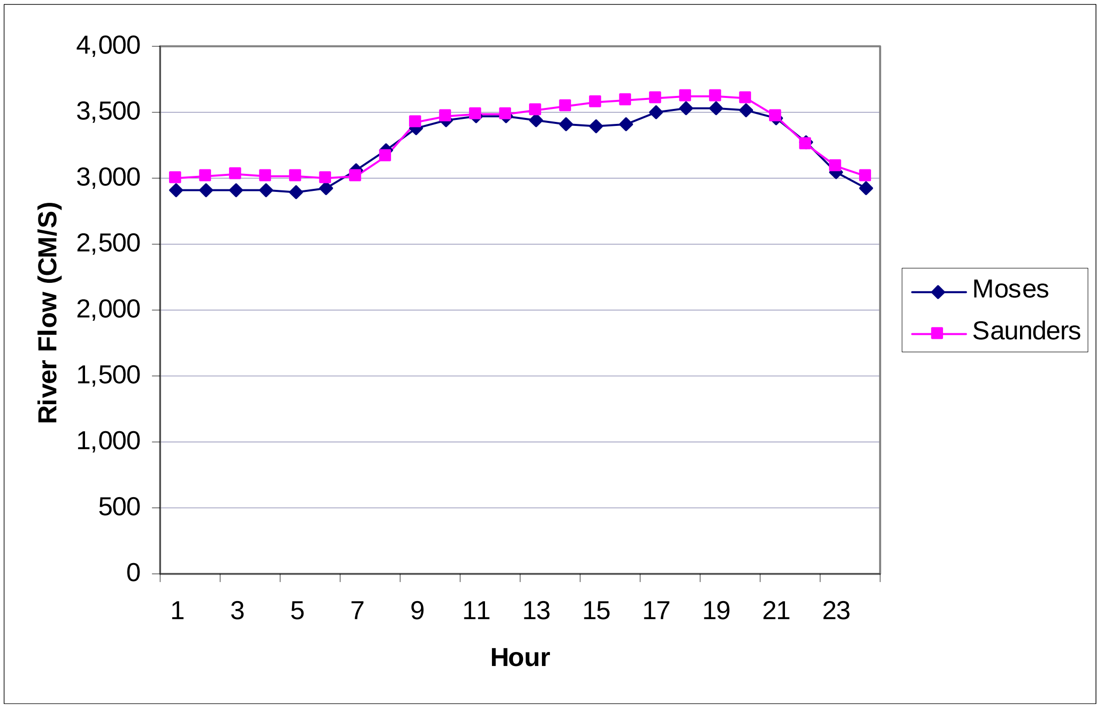
Figure 3: Quarter-Month Energy Prices



The prices shown in the previous graph are the average for all hours of the period. The next question is to what degree can generation be scheduled within any given period to secure the best hourly prices, and thus achieve an average generation price greater than the simple hourly average.

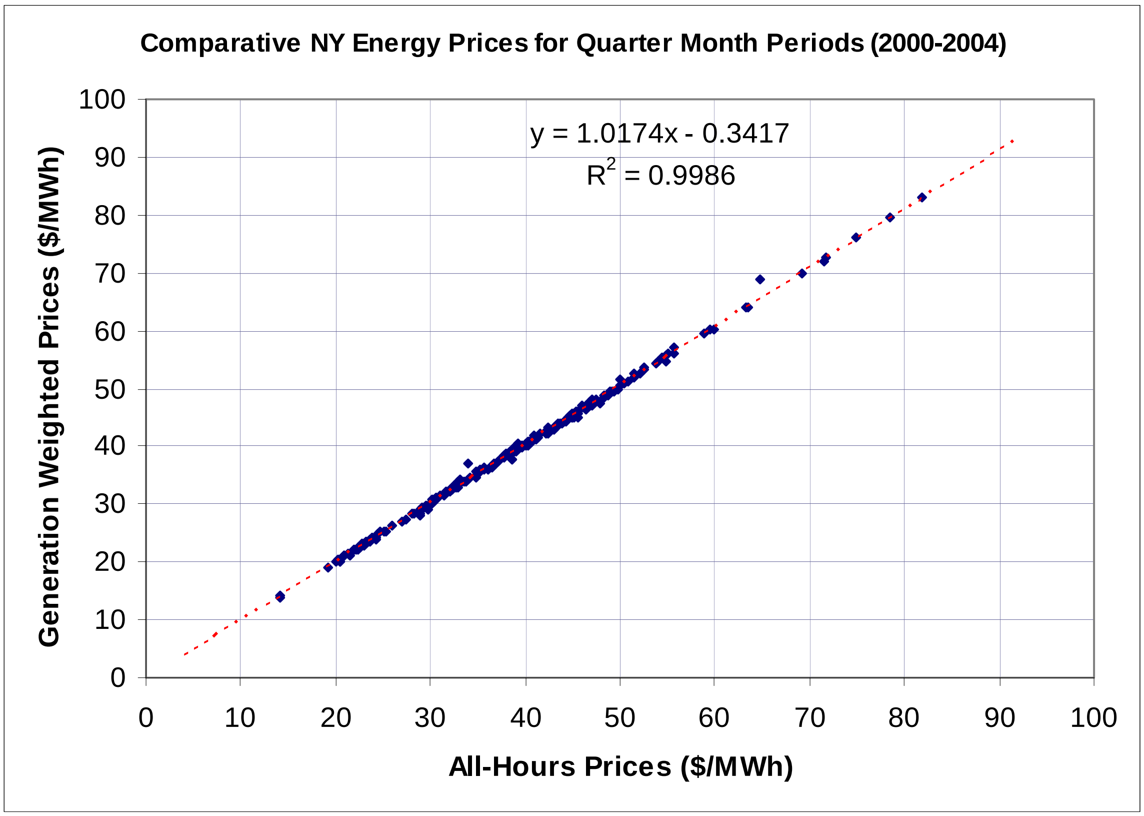
On average, the change in hourly generation over the course of a day for the Moses and Saunders facilities is fairly limited as shown by the flow levels in the figure below. However, the pattern varies during the year, and the minimum generation can be more than 30% below the peak level at some times, but is less than 1% at others. The average daily difference is about 20%. Although there are some operational differences between Moses and Saunders, their daily generation patterns tend to be very similar. This indicates the current degree of flexibility in the dispatch of these units.

Figure 4: Average Hourly Flow Patterns in 2003



The next we calculated the difference between the simple average of hourly prices and the average of those hourly prices *weighted by generation amount*. For this purpose we matched the hourly generation from Moses with the hourly energy prices for the NY North zone. Based on the daily generation pattern shown above, we expected the generation-weighted prices to be greater. However this was not true for the quarter-month averages. As shown in the scatter chart below, there is very little difference between the two types of prices. Overall the generation-weighted price has about a 1½% premium, but there is considerable uncertainty in the data with a few high side points possibly shifting the curve upwards. One reason for the small benefit are the small differences in generation between the hours of the day, i.e. on an annual basis, the standard deviation of hourly generation within a quarter-month period is about 5%. In some periods there is absolutely no correlation between generation levels and prices. Another factor is that generation varies little between week and weekend days, although prices during the weekend are lower. This matter is discussed in more detail in Appendix C. For our present purposes we will use the all-hours energy price for the value of hydroelectric generation, but will further explore this issue.

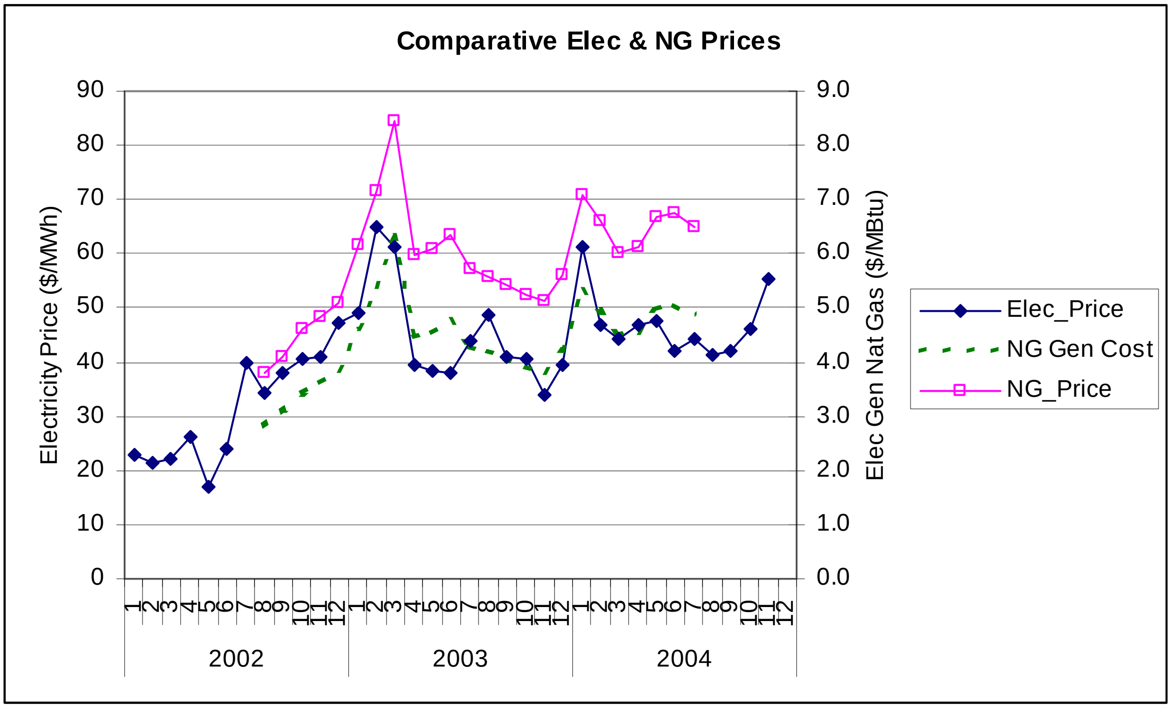
Figure 5: Average vs. Generation-weighted Average Energy Prices[2]



[2] Energy prices are real-time NY North prices from the market start of July 2000.

As a final piece of the historical analysis, we examined some drivers for the recent electricity prices. Much of the marginal electricity generation that sets the market price in the US Northeast is fired by natural gas. Thus, we looked first at the comparative natural gas and electricity prices over the last three years. As shown in the next graph, the monthly trends in those two prices are very similar. The dashed line represents marginal fuel cost for generation from a natural gas combined cycle plant. Also relevant, but not included in this graph would be the plant's variable operating and maintenance costs. In the next stage of this project we will extend and refine the use of natural gas price forecasts to develop short to intermediate-term forecasts for electricity prices.

Figure 6: Relationship Between NY Electricity and Natural Gas Prices[3]



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[3] Electricity prices are all-hour monthly averages for the NY North Zone. Natural Gas prices are the average delivered costs for electric generation in NY state from EIA. The conversion heat rate used for a combined cycle plant was 7,500 Btu/kWh.

Forecasts

The starting points for both the short-term and long-term forecasts will be the recent prices and the electricity futures markets. In the section below we will discuss that data and the approach taken to develop the near-term all-hours electricity prices.

In developing the energy price forecasts, we looked first at the futures market for electricity. Futures market data is only available for a few areas of the northeast as shown in the table below. Ontario electricity price data is available for the province as a whole and not specifically for the Saunders area[4]. There is information for three zones for New York, but not for the North zone near Moses. Prices for futures contracts at this time are fairly high for the summer and winter peak periods, but are much lower for full calendar year contracts. There is also a slight decline in future contract prices from 2005 to 2006. There is a considerable difference between the futures and recent historical data. For example the 2004 peak period price for NY-G was $58.3/MWh, whereas the futures price for the peak period during the 2005 calendar year is $17/MWh greater. There appears to be an inconsistency between the US and Canadian futures in that Ontario prices in US$ are significantly below those for NY. One possible explanation may be that the futures market represents an expectation of a rise in the relative value of the Canadian dollar, but there is no consensus among economists about where exchange rates will go in the coming year.

Table 1: Peak Period Electricity Price Futures[5]

	NY-A	NY-G	NY-J	Ontario	
Period	West	Hudson	NYC	(Cdn $)	(US $)[6]
2004 Dec	64.8	72.5	93.5	70.5	54.2
2005 Jan	77.5	90.5	150.5	86.5	66.5
2005 Jan/Feb	75.5	89.5	119.5	86.0	66.2
2005 Jul/Aug	69.3	85.3	109.3	84.0	64.6
2005 Cal	65.3	75.3	93.3	73.0	56.2
2006 Cal	58.9	69.2	85.7	71.0	54.6

[4] Nodal pricing does not exist in Ontario at the present time, however the IESO is giving it careful consideration.

[5] Futures prices are for the standard "5x16" peak period product. Ontario products are in Canadian $, all others in US $. The data source is MW Daily 11/3/04.

[6] An exchange rate of 1.30 based on the 2004 average was used for this conversion.

Using the conversion methods discussed in Appendix E, we arrived at all-hour price forecasts for 2005 and 2006 in the NY North Zone for the Moses station. The calendar year futures prices for 2005 and 2006 are relatively high compared to recent year levels (shown in the shaded rows in the following table). Compared to the calendar 2004 price of 46.8 $/MWh, the 2005 price is greater by 10.6 $/MWh and the 2006 price greater by 6.0 $/MWh. But they represent the best market information we have at present and will form the basis for the forecasts.

Table 2: NY-North Forecast Based in Electricity Futures and Historic Prices

Period	NY-G Peak	NY-G All-Hours	NY North All Hours
2003 Cal	56.8	49.0	44.7
2004 Cal	58.2	50.0	46.8
2004 Dec	72.5	64.3	62.6
2005 Jan	90.5	80.7	76.0
2005 Jan/Feb	89.5	79.2	75.0
2005 Jul/Aug	85.3	71.2	62.8
2005 Cal	75.3	63.9	57.4
2006 Cal	69.2	58.7	52.8

All prices are in US$/MWh.

Short Term Forecasts

The next stage was to take the previous monthly and calendar year futures, examine the historic pattern of quarter-monthly prices, and apply a series of adjustments to arrive at a short-term (two year) price forecast. The basic approach is to first determine an annual all-hours energy price and then to apply quarter-monthly adjustment parameters. The methodology is described in more detail in Appendix F. The detailed results are given in Appendix A. The table below shows the historic and forecast all-hours annual prices.

Table 3: Short Term All-Hours Prices – Historic and Forecast

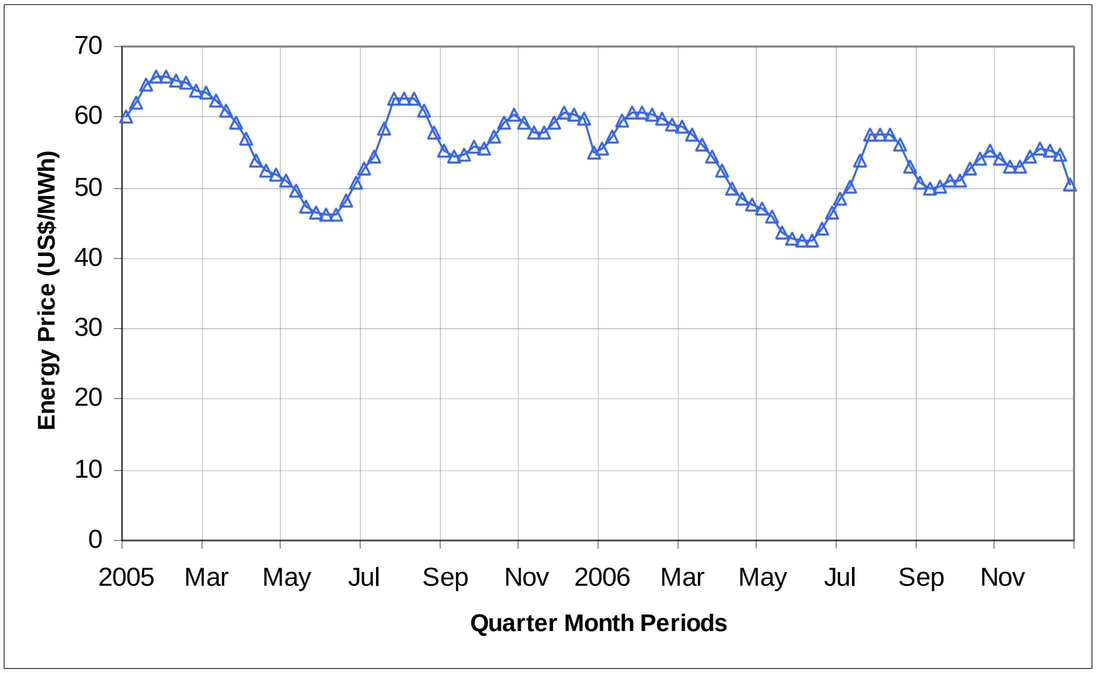
Year	Moses (US$)	Saunders (US$)	Saunders (Cdn$)	Bea/Ced (Cdn$)
2001	32.95			
2002	31.31			
2003	45.07	*52.01*	73.79	#N/A
2004	47.21	*48.23*	63.07	#N/A
2005	57.40	*53.85*	70.00	87.00
2006	52.80	*52.37*	68.08	87.00

Notes: Saunders forecast based in NY futures.
Moses forecast based on historic values with partial adjustment for NY futures.
Bea/Ced forecast based on values provided by HQ.

For the hydro facilities in Quebec we used a flat annual price of 87.00 Cdn$/MWh based on Hydro Quebec's valuation of the worth of its marginal generation. HQ has surplus generating capacity a large portion of which is hydroelectric with storage capability, so additional generation at any time of year can essentially be saved and sold or used when the need is greatest and prices are highest. Hence, those peak period prices represent the value of additional generation. As a comparison, the average peak period price for the reference location of Richview Ontario[7] averaged 86.66 Cdn$/MWh during the first 11 months of 2004. For the long term forecasts this flat price is increased at the same rate as the overall increase in Ontario (and NY) prices

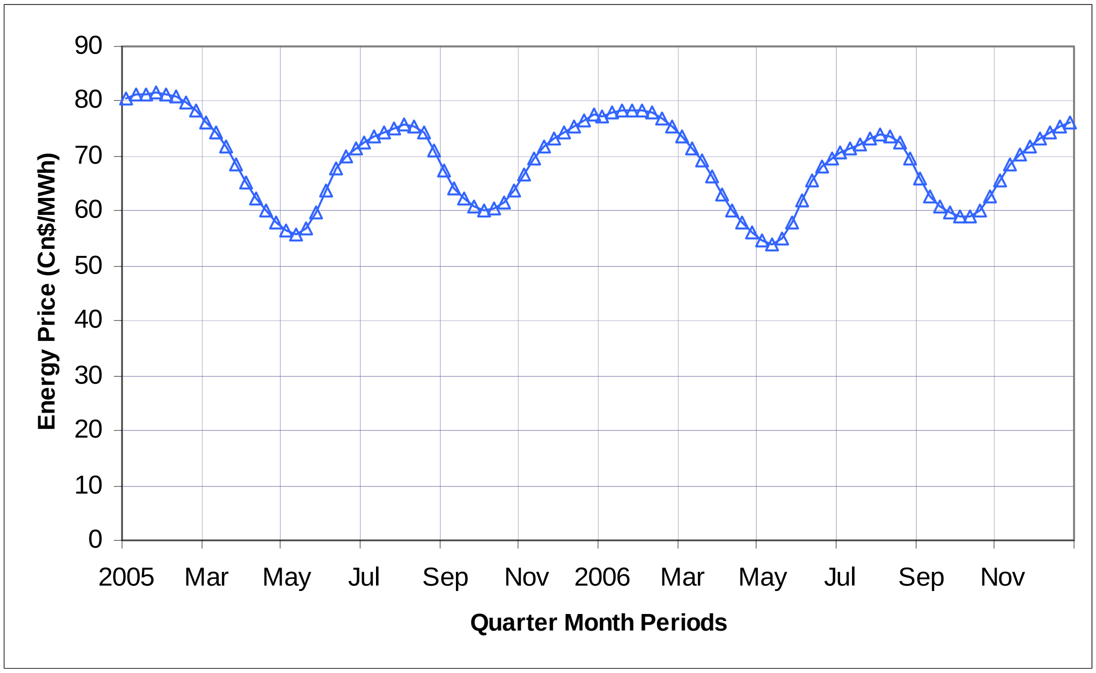
The following graphs show the short-term quarter-monthly price forecasts for Moses and Saunders. For Moses we make use of the patterns shown in five years of market price data. For Saunders we develop an expected price based on a typical energy and peak load pattern. For Beauharnois/Cedars a flat annual price is used with no quarter-month variation.

Figure 7: Short Term All-Hours Electricity Price Forecast for Moses



[7] Although Ontario has not established nodal pricing, the price data provided by IESO does provide values for a number of different locations.

Figure 8: Short Term All-Hours Electricity Price Forecast for Saunders



A forecast of energy prices associated with greater peaking operation could also be valuable. For this purpose, we have calculated the historic ratios of peak period to all-hours prices (see Appendix G). Those ratios are listed in Appendix A and can be used to estimate peak period prices for simulating alternative hydroelectric operating strategies.

These short term price forecasts are however based on a fairly short historical time period and, thus, have a high degree of uncertainty associated with them. Electricity prices can be very volatile even at the quarter-monthly aggregate level for a variety of reasons as is illustrated by the three year history in Figure 3. Appendix H contains a further discussion of some of the uncertainties.

In addition to the energy price forecasts discussed in the first part of this section, there are other products associated with electric generation that may have some relevance for these hydro facilities. These other electricity products are:

1. Reserves (Spinning or Quick Start)—Electric systems may need to add generation rapidly if load increases or a plant goes out of service. Facilities which are on line but operating at less than maximum output or which can start up quickly can provide this reserve service. To qualify for reserve payments, the operators much choose not to run the plant or to run it below maximum capacity. The economic value of this service tends to be substantially less than for generation (>~1 $/MWh), but for a hydroelectric plant it can be provided at near zero cost. Since reserve prices tend to be high when energy prices are high, it is probably better to generate than not to. Although a potential revenue source for these hydroelectric plants, the option to sell reserves in lieu of selling energy is likely to have a negligible effect on scheduling and operation decisions.

2. Automatic Generation Control (AGC) – Some plants have the ability to respond in a nearly instantaneous manner to changes in load. These hydro facilities may or may not have that

ability. Again that probably has no import to operational choices which are the focus of this study.

3. Black Start – Units such as hydro which can start up independently of the electrical grid have a benefit for restoring power after outages. Since this is typically an annual fixed payment, it is not relevant for this study.

4. Capacity – There is a benefit to having enough generating capacity available to meet peak loads and avoid brownouts or blackouts. Several ISO's in the US Northeast are exploring various new designs for capacity markets. A likely form being considered for those markets is a fixed monthly or annual payment based on the capacity available to meet peak load. This has no effect of operational issues, but might be a consideration for future options to increase peak generation capacity at the hydroelectric facilities.

Thus in summary, although these other electricity products could add substantial economic value to these hydroelectric facilities, they have negligible effects on the kind of operational issues that are the focus of the current study.

Long Term Forecasts

Long term forecasts are an attempt to glimpse the unknown and tend to be as often wrong as right. Nevertheless we will attempt to identify a range of possible futures based and what we now know. The primary factors affecting future long-term electricity prices are:

- Fuel Prices
- Technology
- Environmental Factors
- Electricity Demand

There is considerable uncertainty about future fuel prices. The marginal cost of electricity in the US Northeast and Eastern Canada is strongly influenced by the cost of natural gas. In the last several years, there has been a large rise in the price of natural gas as demand has increased for new, clean electrical generation. The consensus view is that natural gas prices will decline from their current highs, but there is no consensus about how much they will decline or for how long. The futures market for natural gas goes out for six years and suggests a 30% decline in prices by 2010, but trading in the futures market very thin in the later periods and based on past history it is not always a reliable predictor of actual prices. Since natural gas demand in North America outpacing production, imported LNG is likely to establish the market price in the future. How rapidly these new supplies can be brought to market is uncertain. Construction of the infrastructure for LNG transport is a very capital intensive process, and new terminals also often encounter opposition. Another factor is that LNG is part of the world energy market and thus affected by demand in other countries and also in competition with other fuels.

Although petroleum is not much used for electric generation in our regions of interest, it is for some uses a competitor with natural gas. Over the intermediate to long term, trends in oil prices are likely to be affected by trends similar to those affecting natural gas prices. Since the price of oil is affected by both political and geological factors, considerable uncertainty exists. Some petroleum geologists believe that the world is close to the time of peak oil (i.e. maximum production level) and that after that time supply and demand will diverge producing much higher prices. If that is true, then the current consensus forecasts could be very wrong.

There appears to be no shortage of coal in North America, and coal prices have been flat or even in some cases declining. However coal mining and burning have a number of environmental problems (including global warming) which are likely to increase the future costs of using this fuel.

There are a number of promising improved and new technologies for electric generation – wind, solar photovoltaic, combined cycle gas turbines, coal gasification and perhaps even advanced nuclear power designs. Many of these will probably find a place in the future electrical generation system. However none of these appear to offer the potential for any breakthroughs in lower overall production costs. For example, those technologies such as wind with close to zero variable costs have high fixed costs that need to be recovered. Also, some renewable technologies such as wind and solar are not dispatchable. Thus fossil generation, and to a large extent natural gas, will likely set the marginal cost of electricity for at least the next several decades.

Environmental factors will also affect the cost of generation with fossil fuels. There are currently restrictions on SOx and NOx emissions which add to the cost of burning fossil fuels either by the purchase of emission credits or the addition of control devices. Restrictions on mercury emissions are likely to be established in the near future, and will have a significant effect on coal. But the big elephant in the room of unknown size are carbon emissions. The Kyoto protocol is now in effect, and Canada is a signatory. Our investigations on carbon policy impacts have resulted in several observations relevant to this project[8]:

- New Brunswick Power is assuming that the Canadian Government's Kyoto policy (which is not yet finalized) will result in a cap and trade system, and that the costs of allowances will be CDN$10/metric ton of CO2 for the first compliance period of 2008-2012, and CDN$15/metric ton for the second compliance period of 2013 and beyond. Both of these are assumed to escalate at 2% per year. This translates to CDN$9.07/ton for the first compliance period and CDN$13.61/ton-CO2 for the second period.

- In 2003 ICF was retained by the state of Connecticut to model a carbon cap across the 10 northeastern states. This modeling, using the IPM model, projected carbon allowance costs at: $6.70/ton in 2010, $8.70 in 2015 and $11.00 in 2020.[9] These are all in 2003 US$.

- In its Avoided Cost Docket (A.04-04-025), the California Public Utility Commission had a report prepared recommends a carbon cost of $12.50 per ton starting in 2008.[10] Other studies assessing the cost of carbon in the US include estimates that range from roughly $8 to $60 per ton. Numbers at the higher end of this range tend to come from studies that model electric-sector carbon regulations or otherwise estimate the cost of reducing carbon. One such study is the US Energy Information Administration's analysis of the McCain/Lieberman bill (S.139), which estimates the cost of carbon allowances in the range of $22 to $60.[11] The low end of this range is the $8 per ton figure used by PacifiCorp in the base case for its 2003 Integrated Resource Plan. PacificCorp also evaluated scenarios with carbon priced at $2, $25 and $40 per ton.[12] Another utility, Idaho Power Company, recently evaluated its Integrated Resource Plan in the context of carbon at $12.30 per ton and $49.21 per ton.[13]

A carbon emission cost will affect coal more than lower carbon fossil fuels such as natural gas. At a price of $10/metric ton of CO2, the impact on the generation cost for a typical coal plant would be about 9.50 $/MWh, while for a new natural gas combined cycle plant the impact would be about 3.70 $/MWh. This is a modest amount compared to the current costs of electricity, but such costs are likely to increase over time and may be enough to cause changes in the generation mix.

In terms of impacts associated with shifts in hydro generation, the most likely fuel to be displaced when electricity prices are high is natural gas which has a low carbon emission factor. When coal is the marginal fuel with higher carbon rates, the electricity prices are generally lower. To the extent that externalities are fully reflected in emission taxes, then the best policy for hydro plants is to generate more when prices are high and less when they are low.

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[8] This information was assembled by Geoff Keith of Synapse Energy Economics.

[9] Center for Clean Air Policy, Connecticut Climate Change Stakeholder Dialogue: Recommendations to the Governors' Steering Committee, January 2004, p. 3.3-27.

[10] Environmental Exposures in the U.S. Electric Utility Industry, complete cite.

[11] US Energy Information Administration, *Analysis of S.139, the Climate Stewardship Act of 2003*, EIA Report: SR/OIAF/2003-02, June 2003.

[12] See: PacificCorp, *Integrated Resource Plan 2003*, pages 45-46.

[13] See: Idaho Power Company, *2004 Integrated Resource Plan Draft*, July 2004, page 59.

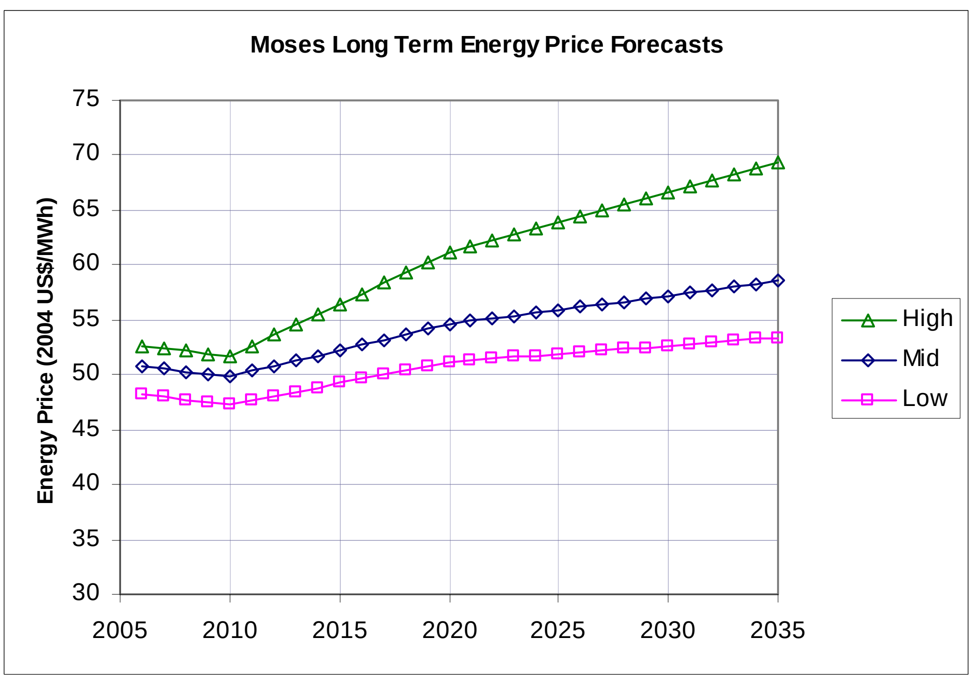
Another factor related to fuel mix is the recent legislation in Ontario to phase out existing coal plants over the next several years. How soon this takes place and how rapidly new generation facilities can be brought on line would definitely affect prices in that province. Even with predicted reductions in natural gas prices, overall electricity prices in Ontario are more likely to stay at current levels or to rise rather than to decline.

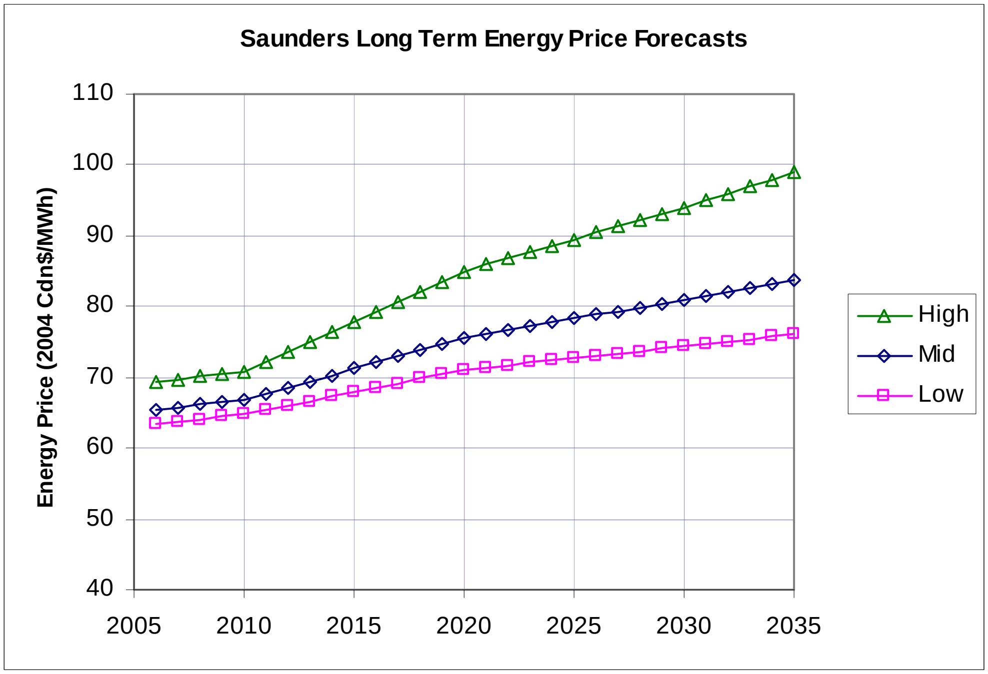
Demand changes have both short term and long term effects on the electrical generation system and prices. In the short term, high demand produces high prices. If there are frequent periods of high demand and prices in the hundreds of dollars per MWh, then that will affect overall energy prices and hydro plant revenue. Over the longer term, the increase in peak demand determines how much new generating capacity is needed and thus investment costs, but also provides the opportunity for the addition of more efficient resources. Our expectation is that electricity demand will continue to grow but probably at more modest rates than in the past because of higher electricity prices.

The methodology we have used for developing the long term forecasts is discussed in Appendix I. The starting point are the technologies and energy price forecasts in the base case of the U.S. Energy Information Agency's 2005 Annual Energy Outlook. We then use information from other sources, such as electricity and natural gas futures markets, emission prices and other studies to produce mid, high and low forecasts. However we caution that all long-range price forecasts may be proved wrong by unanticipated events. Note that these prices represent the energy value of the hydroelectric generation. There is also a capacity value in the range of $80 to $100 per kW-year, but which is not relevant for the present purposes of river regulation and generation analysis.

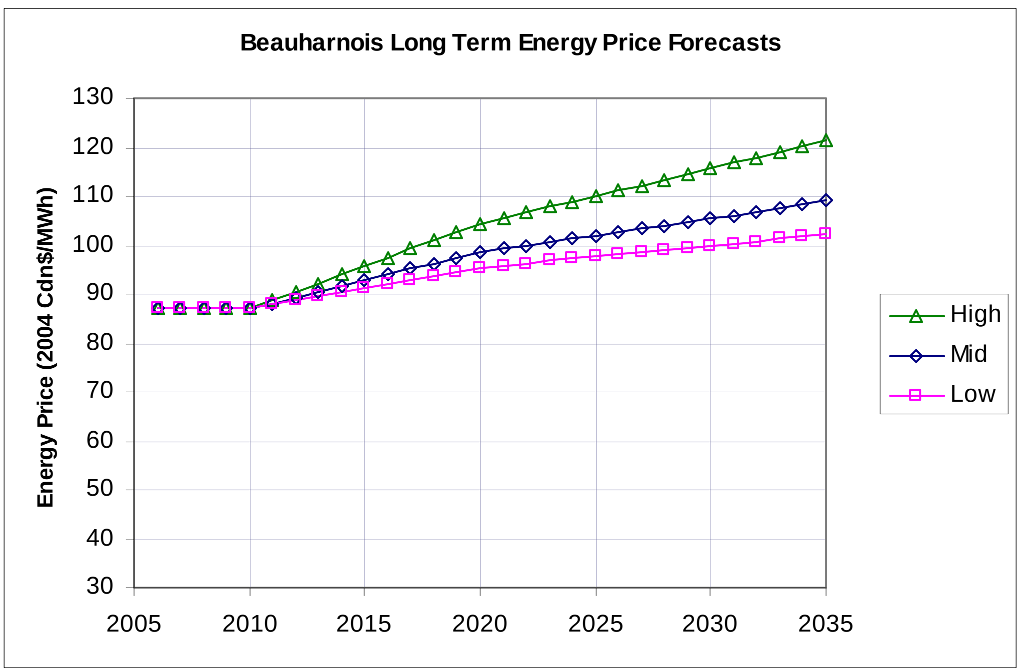
Our long term forecasts are shown in the following three figures, and the year by year long term forecast data are tabulated in Appendix B.

Figure 9: Long Term Electricity Price Forecasts





Saunders Long Term Energy Price Forecasts
Energy Price (2004 Cdn$/MWh)
110
100
90
80
70
60
50
40
2005
2010
2015
2020
2025
2030
2035
High
Mid
Low



Beauharnois Long Term Energy Price Forecasts
Energy Price (2004 Cdn$/MWh)
130
120
110
100
90
80
70
60
50
40
30
2005
2010
2015
2020
2025
2030
2035
High
Mid
Low

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Appendix A – Short Term Wholesale Electricity Price Forecasts

Short Term All-Hours Forecast ($/MWh)				
All-Hours	**Moses (US$)**		**Saunders (Cdn$)**	
Qtr_Mon	**2005**	**2006**	**2005**	**2006**
1	60.10	55.56	80.52	77.40
2	62.10	57.39	81.09	78.00
3	64.57	59.65	81.41	78.34
4	65.73	60.70	81.50	78.47
5	65.78	60.74	81.32	78.33
6	65.35	60.33	80.75	77.82
7	64.93	59.94	79.71	76.85
8	63.85	58.93	78.21	75.43
9	63.51	58.61	76.33	73.64
10	62.50	57.66	74.15	71.56
11	61.03	56.30	71.66	69.17
12	59.19	54.60	68.55	66.19
13	56.95	52.52	65.25	63.01
14	54.02	49.82	62.28	60.16
15	52.50	48.40	60.01	57.99
16	51.80	47.75	57.91	55.99
17	51.04	47.04	56.32	54.49
18	49.77	45.86	55.77	53.99
19	47.45	43.71	56.86	55.09
20	46.43	42.76	59.93	58.11
21	46.13	42.47	63.92	62.03
22	46.10	42.44	67.61	65.66
23	48.10	44.26	69.98	68.00
24	50.65	46.60	71.53	69.55
25	52.65	48.43	72.60	70.64
26	54.58	50.19	73.43	71.47
27	58.57	53.84	74.23	72.29
28	62.77	57.70	75.14	73.22
29	62.60	57.53	75.75	73.85
30	62.81	57.71	75.60	73.75
31	61.12	56.14	74.16	72.38
32	57.77	53.05	71.11	69.45
33	55.21	50.69	67.41	65.89
34	54.44	49.96	64.13	62.74
35	54.60	50.10	62.16	60.86
36	55.76	51.15	60.87	59.65
37	55.63	51.02	60.22	59.06
38	57.39	52.63	60.33	59.20
39	59.24	54.32	61.40	60.28
40	60.36	55.34	63.79	62.64
41	59.26	54.32	66.81	65.62
42	57.77	52.94	69.67	68.44
43	57.84	52.99	71.67	70.43
44	59.31	54.33	73.17	71.92
45	60.67	55.57	74.38	73.14
46	60.51	55.41	75.45	74.22
47	59.80	54.74	76.50	75.28
48	55.05	50.36	77.46	76.25
Average	57.40	52.80	70.00	68.08

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Peak Period Price Ratios		
Qtr_Mon	**Moses**	**Saunders**
1	1.132	1.223
2	1.137	1.215
3	1.142	1.217
4	1.148	1.228
5	1.154	1.227
6	1.160	1.222
7	1.165	1.220
8	1.171	1.217
9	1.177	1.217
10	1.182	1.212
11	1.187	1.238
12	1.192	1.255
13	1.196	1.278
14	1.200	1.317
15	1.203	1.352
16	1.206	1.403
17	1.208	1.444
18	1.209	1.487
19	1.210	1.547
20	1.210	1.542
21	1.210	1.520
22	1.209	1.466
23	1.208	1.407
24	1.206	1.366
25	1.203	1.317
26	1.200	1.302
27	1.197	1.299
28	1.193	1.330
29	1.189	1.336
30	1.184	1.332
31	1.180	1.322
32	1.175	1.288
33	1.170	1.239
34	1.166	1.224
35	1.161	1.230
36	1.157	1.230
37	1.154	1.230
38	1.150	1.229
39	1.148	1.232
40	1.146	1.250
41	1.145	1.259
42	1.146	1.247
43	1.147	1.238
44	1.150	1.230
45	1.155	1.230
46	1.161	1.237
47	1.170	1.235
48	1.180	1.238
Average	1.176	1.294

Appendix B –Long Term Wholesale Electricity Price Forecasts

Long Term All-Hours Energy Price Forecasts

	Moses (US2004$)			Saunders (Cdn2004$)			Beauharnois (Cdn2004$)		
Year	Mid	Low	High	Mid	Low	High	Mid	Low	High
2005									
2006	50.7	48.2	52.7	65.4	63.5	69.4	87.0	87.0	87.0
2007	50.5	48.0	52.4	65.8	63.8	69.7	87.0	87.0	87.0
2008	50.3	47.8	52.2	66.1	64.1	70.1	87.0	87.0	87.0
2009	50.1	47.5	51.9	66.4	64.5	70.4	87.0	87.0	87.0
2010	49.8	47.3	51.7	66.8	64.8	70.8	87.0	87.0	87.0
2011	50.3	47.7	52.7	67.7	65.4	72.2	88.2	87.8	88.7
2012	50.8	48.1	53.6	68.6	66.0	73.6	89.3	88.7	90.5
2013	51.3	48.5	54.6	69.4	66.7	75.0	90.5	89.5	92.2
2014	51.8	48.9	55.5	70.3	67.3	76.4	91.6	90.4	94.0
2015	52.2	49.2	56.5	71.2	67.9	77.9	92.8	91.2	95.7
2016	52.7	49.6	57.4	72.1	68.5	79.3	94.0	92.0	97.5
2017	53.2	50.0	58.4	73.0	69.2	80.7	95.1	92.9	99.2
2018	53.7	50.4	59.3	73.9	69.8	82.1	96.3	93.7	101.0
2019	54.2	50.8	60.3	74.8	70.4	83.6	97.4	94.6	102.7
2020	54.6	51.2	61.2	75.7	71.0	85.0	98.6	95.4	104.5
2021	54.9	51.3	61.7	76.2	71.4	85.9	99.3	95.9	105.6
2022	55.2	51.5	62.3	76.7	71.7	86.8	100.0	96.3	106.7
2023	55.4	51.6	62.8	77.3	72.0	87.7	100.6	96.7	107.8
2024	55.7	51.7	63.4	77.8	72.4	88.6	101.3	97.2	108.9
2025	55.9	51.9	63.9	78.3	72.7	89.5	102.0	97.6	110.0
2026	56.2	52.0	64.4	78.8	73.0	90.4	102.7	98.1	111.1
2027	56.4	52.2	65.0	79.3	73.4	91.3	103.4	98.5	112.2
2028	56.7	52.3	65.5	79.9	73.7	92.2	104.0	99.0	113.3
2029	56.9	52.5	66.0	80.4	74.0	93.1	104.7	99.4	114.5
2030	57.2	52.6	66.6	80.9	74.4	94.0	105.4	99.9	115.6
2031	57.5	52.8	67.1	81.5	74.7	95.0	106.1	100.3	116.8
2032	57.7	52.9	67.7	82.0	75.0	96.0	106.8	100.8	117.9
2033	58.0	53.1	68.3	82.6	75.4	96.9	107.6	101.2	119.1
2034	58.2	53.2	68.8	83.1	75.7	97.9	108.3	101.7	120.3
2035	58.5	53.4	69.4	83.7	76.1	98.9	109.0	102.2	121.5

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Appendix C – Historic Ability to Capture Peak Prices

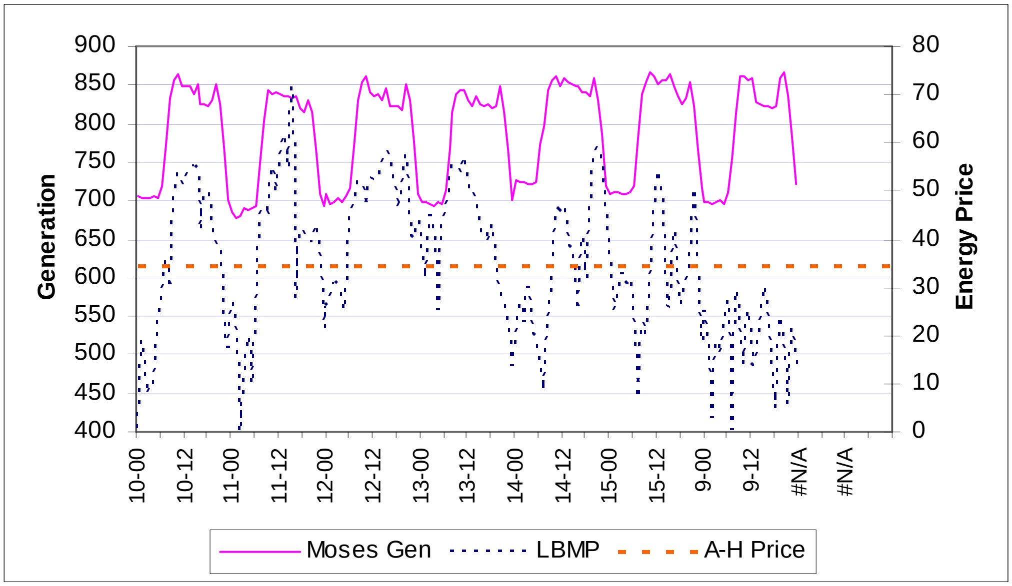
One might think that with its ability to shift generation during the day the Moses-Saunders facilities would be able to obtain an overall electricity price better than the average. However based on the hourly generation and energy prices for 2000-2004, the Moses facility on a quarter-month basis was able to achieve prices only a percent or two above the all-hours average. This was shown graphically in Figure 5 of the main report.

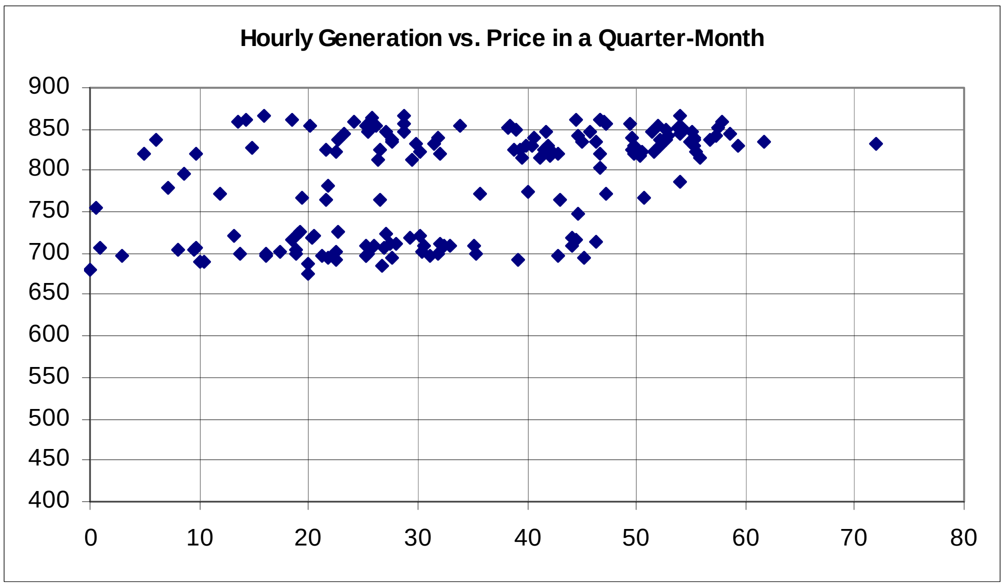
What are the reasons for this? From our analysis of the data, we believe that the primary reason is that generation (for a number of operational reasons) can shift only marginally within a daily or quarter-month period to capture peak prices. This can be illustrated with a hypothetical example. Say that during a given period the ratio of peak to all-hours price is 1.20. Thus a 20% improvement seems possible. However suppose operational reasons limit the generation to between 850 MW and 950 MW. This means that only about 5% of the average generation can be shifted from off-peak to peak. Since the all-hours price is approximately midway between off-peak and peak prices, the maximum average price benefit that one could achieve in this case is 2.0%. But this is further limited by price unpredictability and the ability to change generation levels.

This point can be illustrated further with data from a specific quarter-month: #22 of 2003. During this period the all-hours price was $34.27, the peak price was $41.04 (for a potential premium of 19.8%), and the off-peak price was $28.04 (all in US$/MWh). The generation weighted price for Moses was $34.75, which thus earned a premium of $0.48 (1.40%) above the all-hours price. Thus the generation shifts that did occur were only able to capture 7.1% of the potential benefit.

The first graph below shows the hourly pattern of generation and energy price for this quarter-month. Note first the limited range of the generation changes. This by itself limits the achievable benefit to less than a fifth of the potential. Observe also that the generation pattern was fairly consistent from day to day, even on the final day (which appears to be a weekend) with very low prices. The second chart shows that, while generation is greater for some hours with higher prices, generation is also high in many hours when prices are low. Generation is also low in a number of hours when prices are high. Thus it appears that a number of operational factors limited the ability of the Moses plant to achieve prices very much above the all-hours average. In some quarter-months the match is so bad that the earned price is less than the all-hours price.

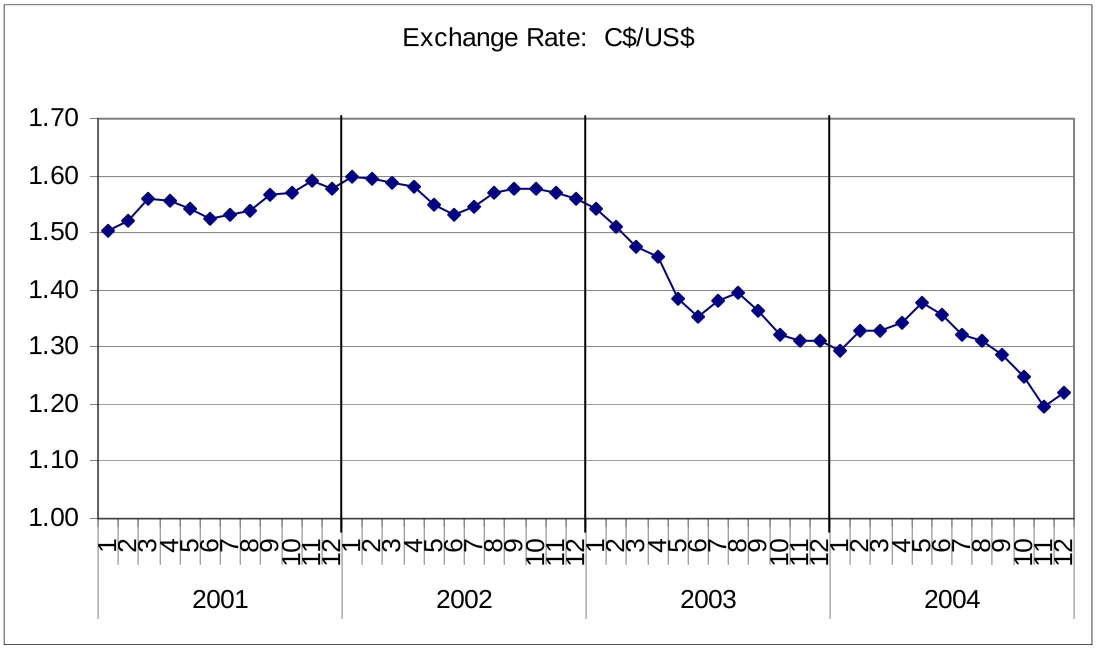
Hourly Generation and Prices for Moses in Quarter-Month 22 of 2003





Appendix D – Currency Exchange Rate

Since we are considering price forecasts for two separate countries the currency exchange rate is a factor both for analyzing past prices and for forecasting future ones. Over the last four years there has been a considerable decline in the value of the US dollar relative to the Canadian one as shown in the graph and table below. Although no one knows what the future will bring, we propose for the purpose of this study to use the average 2004 exchange rate of 1.30 for the future as well. We also believe that the exchange rate adjusted US and Canadian prices for electricity will equilibrate over time because of the interconnection of the electrical transmission system and the significant cross-border transactions.



Currency Exchange Rates: Cdn$ per US$

Month	2001	2002	2003	2004
Jan	1.503	1.600	1.541	1.296
Feb	1.522	1.596	1.512	1.330
Mar	1.559	1.588	1.476	1.329
Apr	1.558	1.581	1.458	1.342
May	1.541	1.550	1.384	1.379
Jun	1.525	1.532	1.353	1.358
Jul	1.531	1.546	1.382	1.323
Aug	1.540	1.569	1.396	1.313
Sep	1.568	1.576	1.363	1.288
Oct	1.572	1.578	1.322	1.247
Nov	1.592	1.571	1.313	1.197
Dec	1.579	1.559	1.313	1.219
Average	1.549	1.571	1.401	1.302

Appendix E – Zonal Price Adjustments

What we need for the purposes of this study are quarter-month all-hours electricity prices for the Moses-Saunders and Beauharnois/Cedars hydro facilities. Much of the available information is however for other locations or periods. Thus, conversion methodologies are needed. The primary basis for our conversions is the hourly locational price data for NY and Ontario. From that data we can develop relationships between zones and between prices in different locations and periods as needed.

One need is to convert between the futures prices for peak hours in one zone into all-hours prices for other zones, particularly from futures for peak prices in Hudson Valley to all-hours prices in NY-North. Using the hourly prices in these two locations for the years 2002-2004, we have developed the relationships in the following table. The first column represents the premium of the peak-period relative to the all-hours price for each month. The second column represents the ratio of the all-hours prices in NY-North to those in the Hudson Valley. Although peak period prices are highest in the Summer, the greatest premiums (but not generally the highest prices) are in the late Spring months because the off-peak prices are lowest then. The differences between the NY-North and Hudson Valley prices are less in the Winter and greater in the Summer because the NY-North zone has a comparatively lighter air conditioning load.

Period and Zonal Price Relationships for 2002-2004

Month	Hud Valley Peak Period Premium	NY-North /Hud Val Price Ratio
Jan	12.1%	0.941
Feb	13.9%	0.954
Mar	13.1%	0.872
Apr	19.1%	0.795
May	29.0%	0.790
Jun	25.4%	0.872
Jul	22.0%	0.894
Aug	17.6%	0.872
Sep	17.0%	0.941
Oct	12.9%	0.924
Nov	18.4%	0.956
Dec	12.7%	0.973
Year	17.8%	0.899

Similar analysis for Saunders shows a much higher premium for peak period prices compared to the all-hours price.

Saunders Peak Period Price Premium

Month	2002	2003	2004	Average
1		21.7%	29.8%	25.7%
2		13.3%	24.0%	18.7%
3		21.4%	24.3%	22.8%
4		33.7%	29.7%	31.7%
5		51.1%	59.0%	55.0%
6		41.0%	50.3%	45.7%
7		37.0%	20.3%	28.7%
8		43.9%	29.1%	36.5%
9		19.7%	20.1%	19.9%
10	33.0%	18.7%	19.1%	23.6%
11	26.0%	33.6%	24.7%	28.1%
12	19.6%	16.1%		17.9%
Year	26.2%	29.3%	30.0%	29.5%

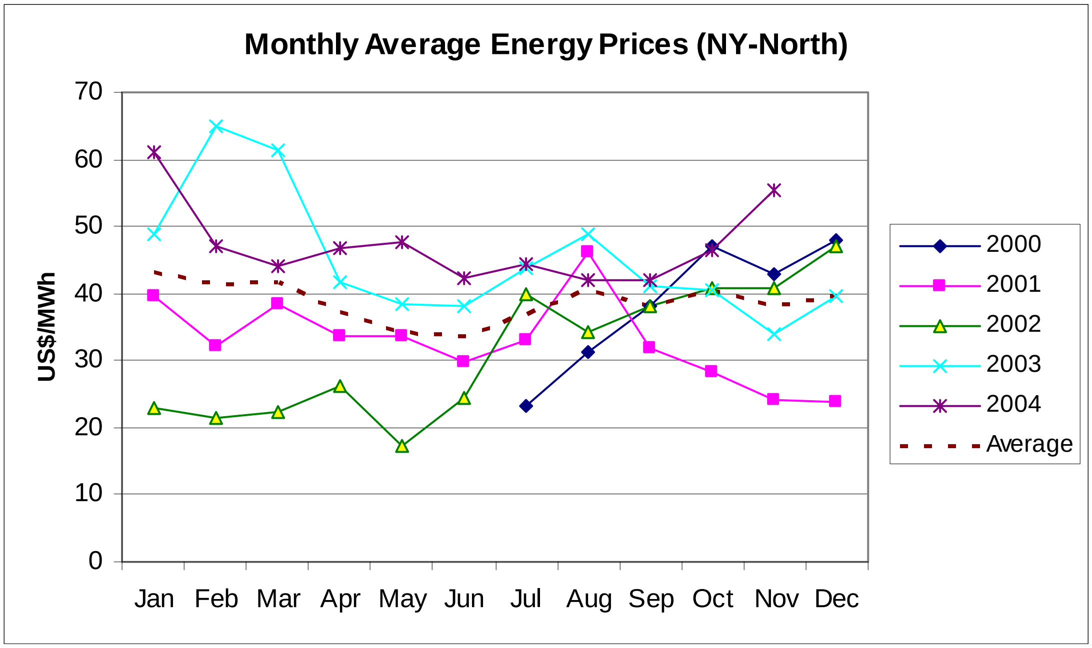
However prices at Saunders are very close to the Ontario reference point of Richview. (Although Ontario does not have nodal market prices, "price" data is reported for a number of locations.) We consider the values for August and September of 2004 to represent unusual conditions and will use a simple year around average price difference of -2.0%.

Saunders All-Hours Price Relative to Richview

Month	2002	2003	2004	Average
1		-1.0%	-3.9%	-2.5%
2		-1.0%	-4.0%	-2.5%
3		-0.5%	-4.0%	-2.2%
4		-1.7%	-2.9%	-2.3%
5		-1.0%	-1.7%	-1.4%
6		-2.0%	-1.1%	-1.6%
7		-1.9%	-1.0%	-1.5%
8		-1.0%	-17.1%	-9.1%
9		-1.0%	-20.6%	-10.8%
10	-1.0%	-2.5%	-1.2%	-1.6%
11	-0.9%	-4.0%	-0.7%	-1.9%
12	-1.0%	-3.9%		-2.4%
Year	-1.0%	-1.8%	-5.3%	-3.3%

Appendix F – Seasonal Price Variations

What is the seasonal variability of electricity prices? Generally they are high when loads are high, but unexpected events, such as plant outages, can produce extremely high prices at any time of year. The following graph and table based on the monthly prices in NY-North for 4 ½ years clearly show that the highest prices occur in the winter and the lowest ones in late spring. Three years (2001, 2002 & 2003) show a definite summer peak. All of the years except for 2002 show some sort of a winter peak. Evidence of a summer peak is more ambiguous with the four-year average of monthly prices in August being 5% above the annual average, but those in July being 5% below.



Monthly Average All-Hours Energy Prices for NY-North

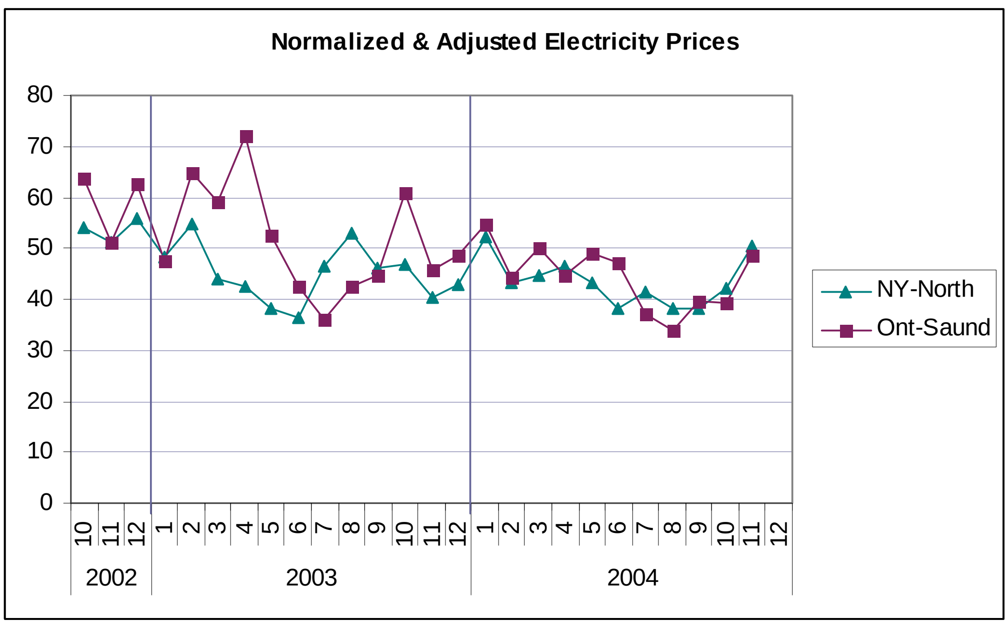
Month	2000	2001	2002	2003	2004	Average	Mon%Dif
Jan		39.5	23.0	48.9	61.1	43.1	11%
Feb		32.2	21.5	64.8	47.0	41.4	7%
Mar		38.5	22.4	61.2	44.2	41.6	7%
Apr		33.8	26.2	41.8	46.9	37.1	-4%
May		33.7	17.2	38.4	47.6	34.3	-12%
Jun		29.9	24.4	38.0	42.3	33.7	-13%
Jul	23.2	33.1	40.0	43.8	44.5	37.0	-5%
Aug	31.3	46.3	34.2	48.7	42.0	40.6	5%
Sep	38.2	31.8	38.1	41.1	42.1	38.2	-1%
Oct	47.1	28.4	40.9	40.4	46.4	40.6	5%
Nov	42.9	24.3	40.8	34.0	55.3	38.2	-2%
Dec	48.1	24.0	47.1	39.6		39.7	2%
Annual	38.4	33.0	31.3	45.1	47.2	38.8	

The next table shows the available two years of market data for Ontario. Although the monthly averages are somewhat skewed because of the very high prices in Feb-Apr of 2003, the winter prices are generally higher. What is unexpected, but consistent across two years of data, is that prices in July & August are substantially below the annual average.

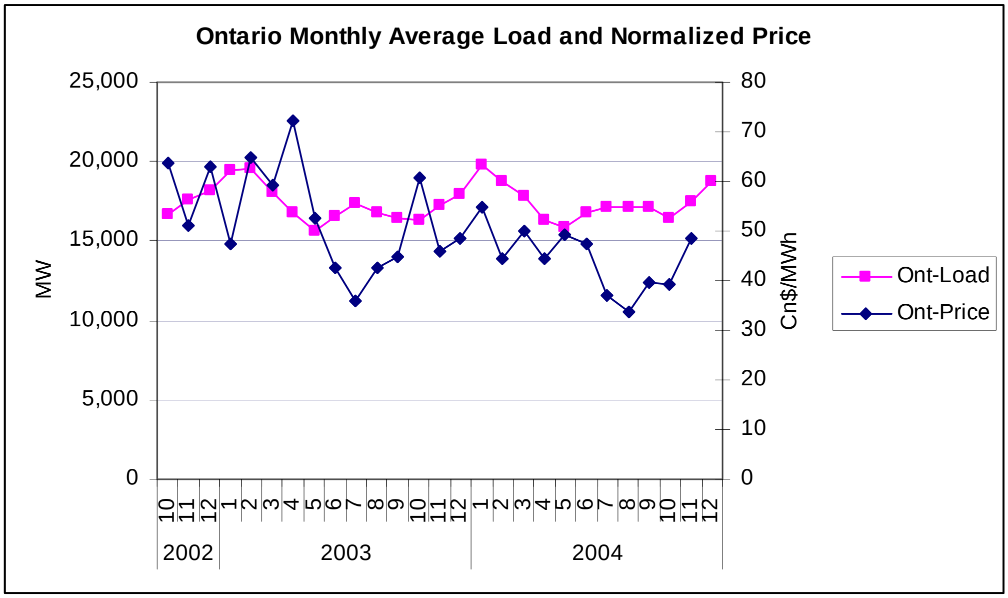
Monthly Average All-Hours Energy Prices for Ontario-Saunders

Month	2002	Mon%Dif	2003	Mon%Dif	2004	Mon%Dif	2002-04	Mon%Dif
Jan			74.28	1%	83.09	32%	78.7	13%
Feb			115.84	57%	64.30	2%	90.1	29%
Mar			121.92	65%	66.11	5%	94.0	35%
Apr			103.31	40%	60.16	-5%	81.7	17%
May			72.75	-1%	74.34	18%	73.5	5%
Jun			60.05	-19%	71.40	13%	65.7	-6%
Jul			46.97	-36%	52.45	-17%	49.7	-29%
Aug			54.55	-26%	48.78	-23%	51.7	-26%
Sep			54.48	-26%	56.12	-11%	55.3	-21%
Oct	76.34	3%	69.45	-6%	53.68	-15%	66.5	-5%
Nov	64.08	-14%	50.82	-31%	64.13	2%	59.7	-14%
Dec	82.47	11%	58.69	-20%			70.6	1%
Annual	74.34		73.79		63.07		69.8	

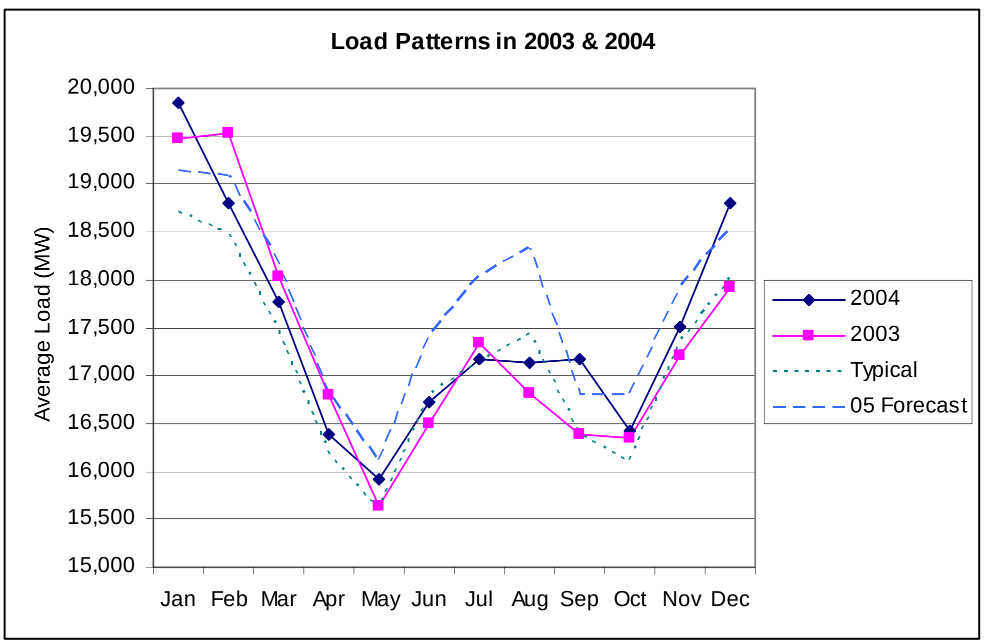
A plausible hypothesis is that month to month variations in natural gas prices are obscuring the underlying normal seasonal variation in electricity prices. In particular a natural gas price spike in early 2003 could be affecting the prices for that period. The following graph shows normalized electricity prices adjusted for natural gas prices and exchange rates. For NY-North there definitely is a pattern of higher winter and summer prices (although the 2004 summer peak is more of a bump). However, for Ontario-Saunders the summer prices are low when compared to the annual average. The good news is that the two sets of prices in a similar range throughout 2004.



Perhaps load changes would explain the remaining variation. The load and price data comparison for Ontario in the next chart show a peak winter load with high prices, with a smaller peak in summer with lower than average prices.

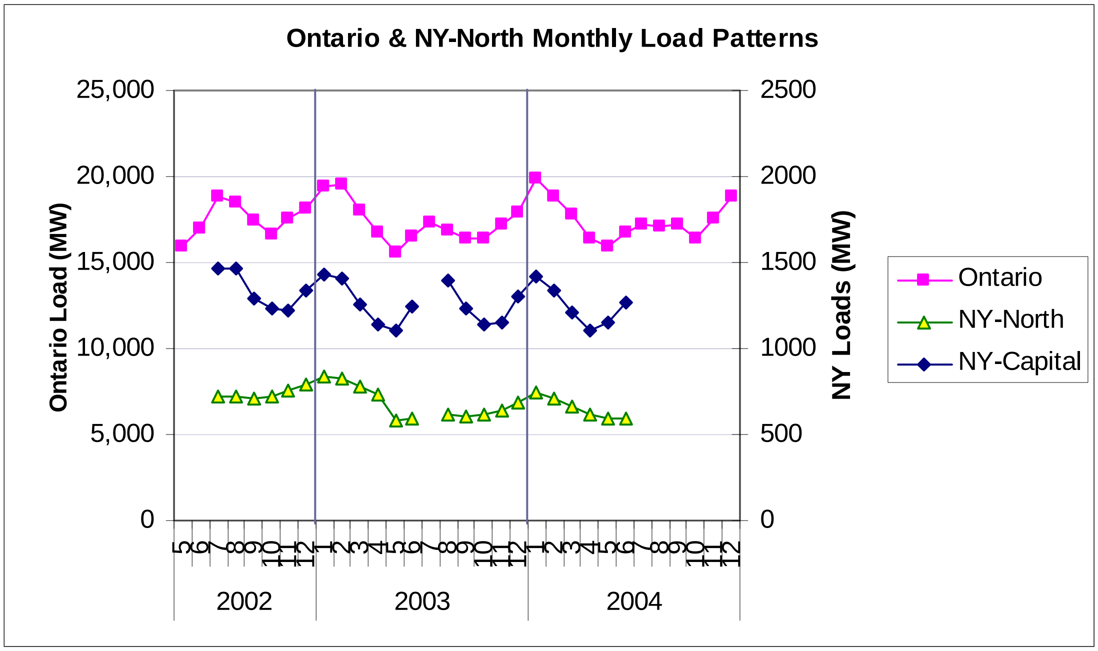


In a number of ways the monthly load patterns in 2003 and 2004 were atypical and this is likely reflected also in the observed price patterns. The graph below compares the actual monthly average loads in 2003 & 2004 compared to average typical pattern of the previous eight years. For both years the August loads were substantially below normal levels and the winter loads were much higher than normal. These factors in combination would tend to increase the winter price and lower the summer peak price. A further comparison with the most recent Ontario forecast[14] indicates an even greater summer load both absolutely and relatively.



[14] "10-Year Outlook: Ontario Demand Forecast", IMO_REP_0173v1.0, March 31, 2004.

Perhaps then loads are the explanation for the difference in seasonal price patterns. A comparison of loads for Ontario and NY-North show similar winter peaks. Ontario's summer load is higher than for the spring and fall, but still much below the winter. Demand in NY-North is actually lowest in the summer which does not correspond to the higher prices then. We believe that prices in NY-North are actually responding to higher loads throughout the NY-ISO. A comparison with loads in the neighboring Capital zone shows higher summer loads that correspond to the higher summer prices observed in the NY-North zone.



Another view of seasonal price effects is available from the futures market for electricity. Futures market data is only available for a few areas as shown in the table below. Ontario electricity price data is available for the province as a whole and not specifically for the Saunders area. There is information for three zones for New York, but not for the NY-North zone near Moses. Prices are fairly high for the summer and winter peak periods (shown by the points connected with dashed lines), but are much lower for full calendar years (represented by points connected by solid lines). There is also a slight decline in calendar year prices from 2005 to 2006. However the futures appear to be inconsistent with the recent actual data (see Figure 3) in that Ontario futures prices when converted to US$ are significantly below those for NY. A further difficulty is that the Ontario futures indicate a significant summer peak price relative to the calendar price which is not supported by recent price (or load) data.

Peak Period Electricity Price Futures[15]

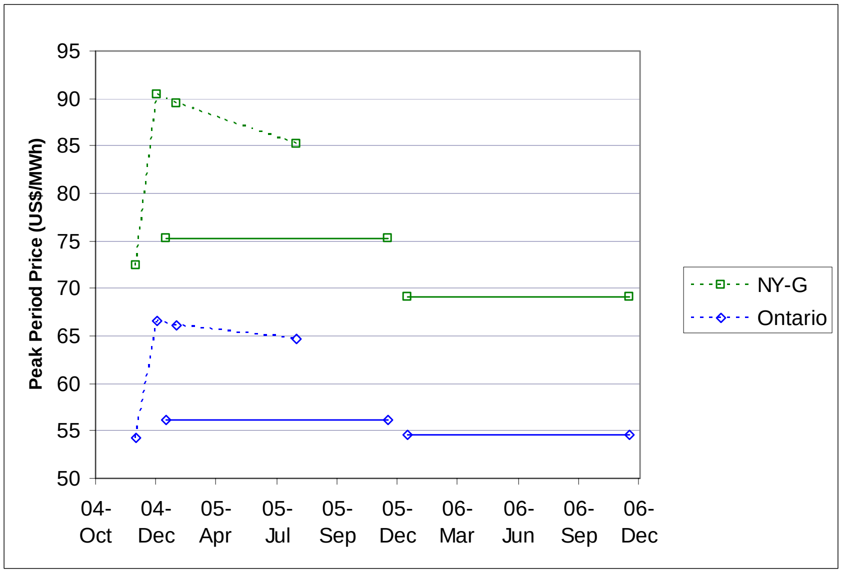
	NY-A	NY-G	Ontario	
Period	West	Hudson	(Can $)	(US $)[16]
2004 Dec	64.8	72.5	70.5	54.2
2005 Jan	77.5	90.5	86.5	66.5

[15] Futures prices are for the standard "5x16" peak period product. Ontario products are in Canadian $, all others in US $. The data source is *MW Daily* 11/3/04.

[16] An exchange rate of 1.30 based on the 2004 average was used for this conversion.

2005 Jan/Feb	75.5	89.5	86.0	66.2
2005 Jul/Aug	69.3	85.3	84.0	64.6
2005 Cal	65.3	75.3	73.0	56.2
2006 Cal	58.9	69.2	71.0	54.6

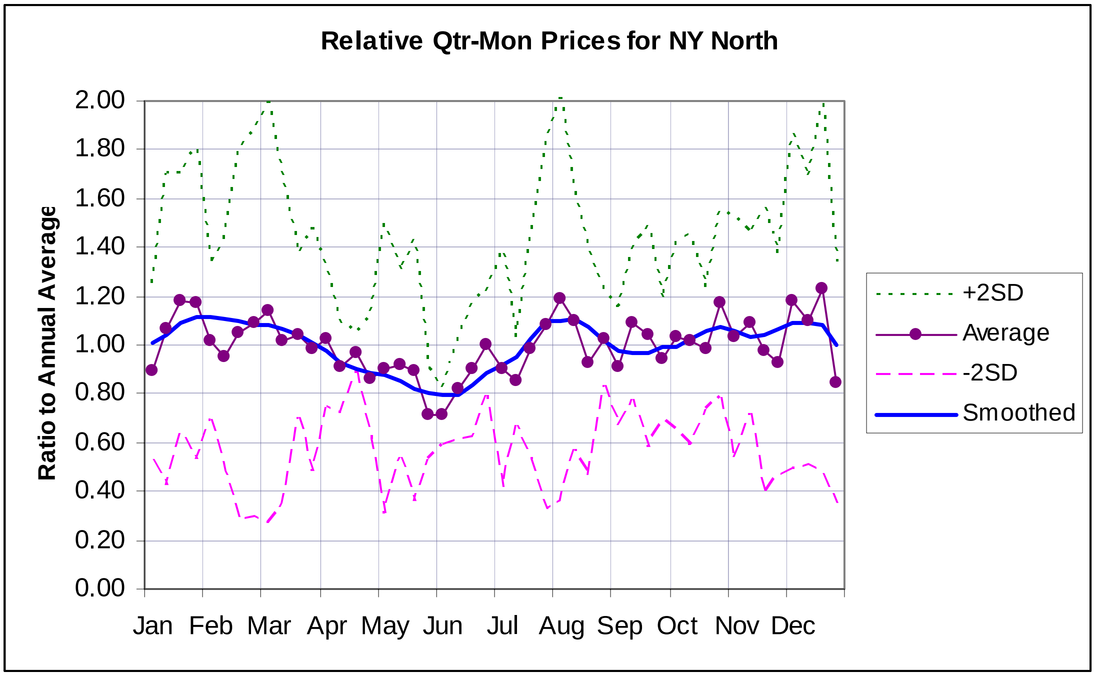
Peak Period Electricity Price Futures



Note: Dashed lines connect monthly and bimonthly prices. Solid lines represent calendar year prices.

This presents some challenges for computing the seasonal variations. The historic data, although scanty, shows different patterns for the two systems. The futures data for New York show even stronger winter and summer variations for 2005 and 2006, and there is convergence between the markets as shown by the overall similarity of the prices in 2004. The traditional solution, if time and resources allowed, would be to run a multi-year multi-region simulation model such as Prosym with historic load and fuel price data for the previous years and best estimates for future years to see what emerges from the systems under different assumptions and conditions.

However, for this study we will have to make use of what is available: (a) the historic prices for the past four years and (b) the futures for 2005. The approach we use is to fit a curve to the historic data and make modest adjustments to reflect relatively higher winter and summer peaks indicated by the futures market. Some basic characteristics are a high and broad winter peak, a more narrow summer peak. Also the first and last periods of the year appear to be lower than the adjacent periods. The late October rise and mid November dip may or may not be artifacts of the data but are included for consideration. Note, too, that there is substantial uncertainty in these quarter-monthly average prices especially during summer and winter. This will be discussed in a later appendix.



Quarter-month to Annual Price Ratios for Moses

Qtr-Mon	Ratio	Qtr-Mon	Ratio
1	1.008	25	0.918
2	1.044	26	0.953
3	1.089	27	1.025
4	1.111	28	1.099
5	1.113	29	1.098
6	1.108	30	1.103
7	1.102	31	1.076
8	1.085	32	1.019
9	1.081	33	0.976
10	1.065	34	0.964
11	1.041	35	0.969
12	1.010	36	0.991
13	0.973	37	0.990
14	0.924	38	1.022
15	0.899	39	1.056
16	0.888	40	1.077
17	0.877	41	1.060
18	0.856	42	1.036
19	0.817	43	1.039
20	0.801	44	1.066
21	0.798	45	1.091
22	0.799	46	1.090
23	0.835	47	1.079
24	0.882	48	0.998

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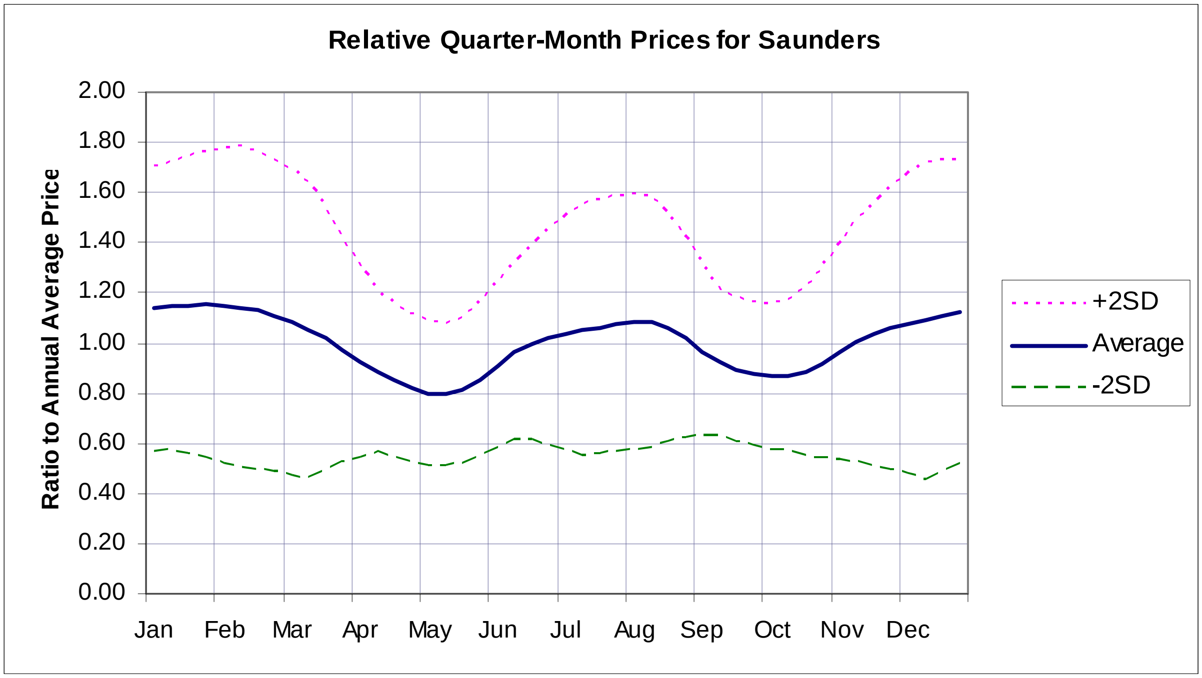
For Ontario, we have just slightly more than two years of price data, but what we have shows some very high peaks in winter and spring, and relatively quite low prices in the summer. For reasons mentioned previously there appear to be some very anomalous conditions during those two years.

What we have done instead is take the historical load patterns combined with most recent forecasts of energy and peak loads to develop quarter-month prices that correspond to those loads. This does not match the pattern of observed prices in the last two years, but rather represents expected prices based on typical load patterns. There are likely other factors such as plant maintenance and run-of-river hydro generation that would affect relative monthly prices, but the scope of this study did not allow their exploration. For example, some experience indicates that lowest prices occur in April rather than May, that would be quite possible if hydro generation was at its maximum in April because of snow melt. We have added an estimate of price uncertainty based on the relative uncertainties shown in the NY North market. However higher prices are much more likely than lower ones.



Quarter Month to Annual Price Ratios for Saunders

Qtr-Mon	Ratio	Qtr-Mon	Ratio
1	1.137	25	1.037
2	1.146	26	1.050
3	1.151	27	1.062
4	1.153	28	1.075
5	1.151	29	1.085
6	1.143	30	1.083
7	1.129	31	1.063
8	1.108	32	1.020
9	1.082	33	0.968
10	1.051	34	0.922
11	1.016	35	0.894
12	0.972	36	0.876
13	0.926	37	0.867
14	0.884	38	0.869
15	0.852	39	0.885
16	0.822	40	0.920
17	0.800	41	0.964

18	0.793	42	1.005
19	0.809	43	1.034
20	0.854	44	1.056
21	0.911	45	1.074
22	0.964	46	1.090
23	0.999	47	1.106
24	1.022	48	1.120
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The 2004 Ontario Demand Forecast predicts Summer energy and peak loads to increase relative to those of Winter. Using that forecast we have developed a projection of how relative monthly prices will change over the period from 2005 through 2014. A value of 1.00 indicates that the monthly energy price is the same as the annual average. As indicated in the table below the January price ratio declines from 1.149 to 1.118, whereas the July price ratio increases from 1.056 to 1.128.

Monthly Price Patterns in Future Years										
PriceRatio	Year									
Month	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Jan	1.149	1.145	1.153	1.150	1.137	1.117	1.122	1.120	1.131	1.118
Feb	1.137	1.130	1.119	1.111	1.106	1.116	1.110	1.108	1.094	1.089
Mar	1.035	1.030	1.011	0.989	0.997	1.023	1.018	0.994	0.977	0.978
Apr	0.867	0.856	0.859	0.865	0.860	0.873	0.866	0.863	0.871	0.866
May	0.797	0.818	0.820	0.814	0.811	0.799	0.806	0.826	0.827	0.822
Jun	0.984	0.985	0.989	0.997	1.017	1.011	1.019	1.017	1.018	1.032
Jul	1.056	1.064	1.076	1.099	1.100	1.091	1.087	1.101	1.122	1.128
Aug	1.076	1.081	1.081	1.063	1.065	1.091	1.107	1.107	1.099	1.093
Sep	0.906	0.898	0.892	0.901	0.904	0.924	0.909	0.895	0.899	0.905
Oct	0.875	0.886	0.897	0.899	0.893	0.880	0.880	0.901	0.901	0.900
Nov	1.021	1.019	1.014	1.001	1.006	0.997	1.002	0.998	0.990	0.982
Dec	1.098	1.087	1.091	1.109	1.104	1.077	1.074	1.070	1.072	1.085

The seasonal price patterns observed in recent years represent the combined effects of loads, generation resources and fuel prices. These are likely to change somewhat in the future, but the precise nature of that change is uncertain. The most likely change is that with the addition of conservation measures and demand response the peaks will be reduced to some degree. Also likely with the addition of wind which is winter resource and solar which is a summer resource is that prices for those periods will be relatively lower than they are now. For NY, this will reduce the prices at the summer and winter peaks. For Ontario, this could reduce both the winter peak and the summer trough. These are the mostly likely future changes in seasonal patterns but insufficient information is available to quantify them to any degree.

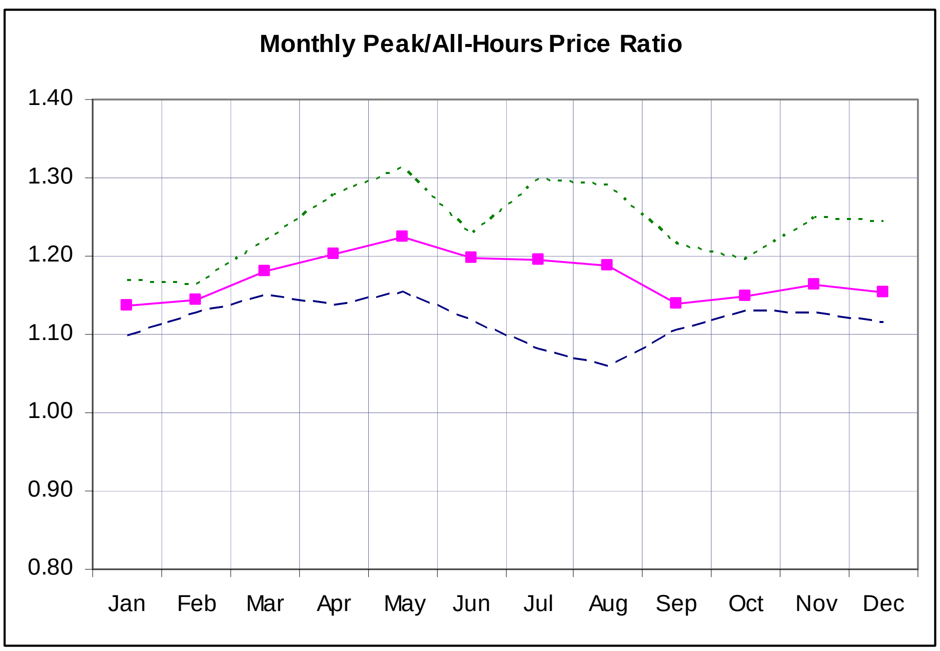
Appendix G – Peak Period Price Ratios

The standard peak period “5x16” represents sixteen morning through evening hours for the five workdays of Monday through Friday. This represents 80 hours out of the weekly total of 168. Thus the “peak” period includes some low-priced early and late hours and does not include any peak price hours that fall on the weekend. Nevertheless the average energy price during the peak period is almost invariably greater than for the off-peak period or the all-hours average. Relative peak period prices tend to be greater during the summer because of air conditioning loads.

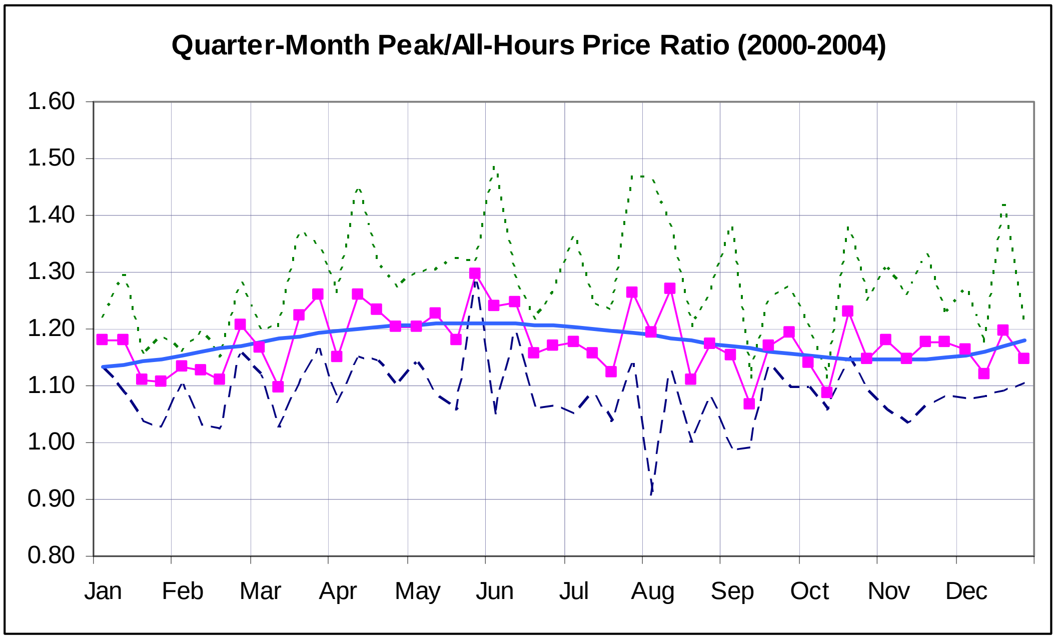
The table and chart below shows the ratios of the monthly average peak-period price to the all-hours price for the NY North area for the years 2000-2004. The ratios are high for some spring months because the all-hours average prices for those months are relatively low (see monthly price graph in previous appendix) and, thus, although peak period prices are modest, the ratios are higher.

NY-North Peak/All-Hours Price Ratio (2000-2004)

Month	Average	Min	Max
Jan	1.14	1.10	1.17
Feb	1.14	1.13	1.16
Mar	1.18	1.15	1.22
Apr	1.20	1.14	1.28
May	1.23	1.15	1.31
Jun	1.20	1.12	1.23
Jul	1.20	1.08	1.30
Aug	1.19	1.06	1.29
Sep	1.14	1.10	1.22
Oct	1.15	1.13	1.20
Nov	1.16	1.13	1.25
Dec	1.15	1.11	1.24
Year	1.17	1.06	1.31



If one looks at the same ratios for the quarter-months, the variations are somewhat greater. The averages vary more from one quarter-month to the next. The dashed lines represent the maximum and minimum values observed during the period from Jun-2000 thru Nov-2004. Clearly some smoothing is needed here. The solid blue line represents a fourth-order fitted curve to the sample data. However, future changes in load patterns and generation resources may result in different relationships between peak and all-hours prices.



Moses Peak to All-Hours Price Ratio for Qtr-Month Periods

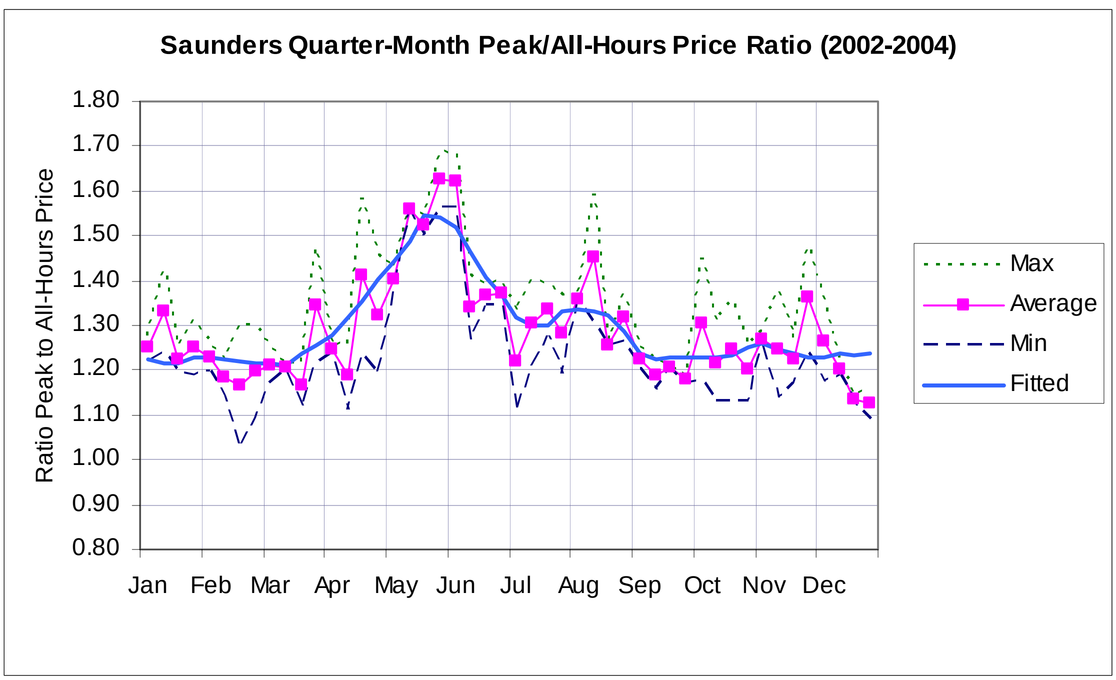
Qtr-Mon	Ratio	Qtr-Mon	Ratio
1	1.132	25	1.203
2	1.137	26	1.200
3	1.142	27	1.197
4	1.148	28	1.193
5	1.154	29	1.189
6	1.160	30	1.184
7	1.165	31	1.180
8	1.171	32	1.175
9	1.177	33	1.170
10	1.182	34	1.166
11	1.187	35	1.161
12	1.192	36	1.157
13	1.196	37	1.154
14	1.200	38	1.150
15	1.203	39	1.148
16	1.206	40	1.146
17	1.208	41	1.145
18	1.209	42	1.146
19	1.210	43	1.147
20	1.210	44	1.150
21	1.210	45	1.155
22	1.209	46	1.161
23	1.208	47	1.170
24	1.206	48	1.180

For Saunders, the peak to all hours price ratios are much greater, as shown in the following table, and the data is much thinner representing only two years. There is however a rough consistency between the same months of different years. The annual average ratio is 1.30 compared to 1.17 for Moses. Also, for both zones the ratios are highest in May and lowest in September.

Saunders Peak/All-Hours Price Ratio

Month	2002	2003	2004	Average
1		1.22	1.30	1.26
2		1.13	1.24	1.19
3		1.21	1.24	1.23
4		1.34	1.30	1.32
5		1.51	1.59	1.55
6		1.41	1.50	1.46
7		1.37	1.20	1.29
8		1.44	1.29	1.37
9		1.20	1.20	1.20
10	1.33	1.19	1.19	1.24
11	1.26	1.34	1.25	1.28
12	1.20	1.16		1.18
Year	1.26	1.29	1.30	1.30

The quarter-month ratios show a wide range of values. We used a moving average with a little manual adjustment to fit the data. Compared to Moses, the values are higher and there is a much greater seasonal variation in the ratio. Based on two years of observations, there is a definite peak in May-June, with a smaller rise in August.



Saunders Peak to All-Hours Price Ratio

Qtr-Mon	Ratio	Qtr-Mon	Ratio
1	1.223	25	1.317
2	1.215	26	1.302
3	1.217	27	1.299
4	1.228	28	1.330
5	1.227	29	1.336
6	1.222	30	1.332
7	1.220	31	1.322
8	1.217	32	1.288
9	1.217	33	1.239
10	1.212	34	1.224
11	1.238	35	1.230
12	1.255	36	1.230
13	1.278	37	1.230
14	1.317	38	1.229
15	1.352	39	1.232
16	1.403	40	1.250
17	1.444	41	1.259
18	1.487	42	1.247
19	1.547	43	1.238
20	1.542	44	1.230
21	1.520	45	1.230
22	1.466	46	1.237
23	1.407	47	1.235
24	1.366	48	1.238

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These observed peak period price ratios are a function of a number of factors. The first and most obvious is the differences in load between peak and off-peak periods. But the underlying driver is the electrical generation supply curve. The greater the range in generation costs between the lower parts of the curve and the higher ones, the greater this ratio. Currently, for Ontario, the lower portion of the supply curve is dominated by nuclear plants and large coal generators with quite low marginal generating costs. If in the future the marginal costs of the base load generating resources increase, then the period price ratios will decrease. However, the addition of new cheap marginal cost resources such as wind and solar could increase these ratios. At this time, we have insufficient information about the future generation mix and costs to predict how the period price ratios might change. However, a reasonable sensitivity to consider is a reduction in the current ratios for Ontario and in increase in the current ratios for New York.

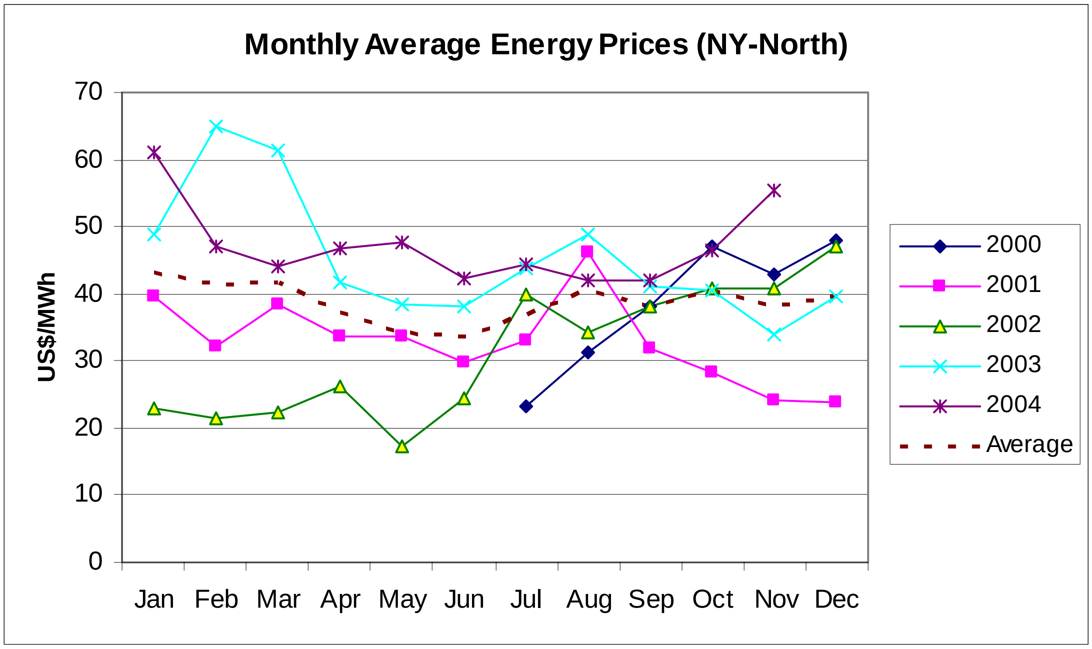
Appendix H – Price Uncertainty

There is substantial variability in electricity prices on all time scales – hourly, daily, weekly, quarter-monthly, monthly and annually. The smaller the time scale the greater the relative variability. The table and graph below show the variations in monthly energy prices for NY-North over the last 4 ½ years. For some months the standard deviation of the prices has been as much as a third of the average price. The seasonal variation in prices, represented by the maximum monthly price difference between January to June of 9.4 $/MWh, is smaller than some of the within month standard deviations.

A similar statistical analysis was done with the quarter-monthly data. The standard deviations for some quarter-month periods is nearly half of the average price, and overall are relatively greater than for the months.

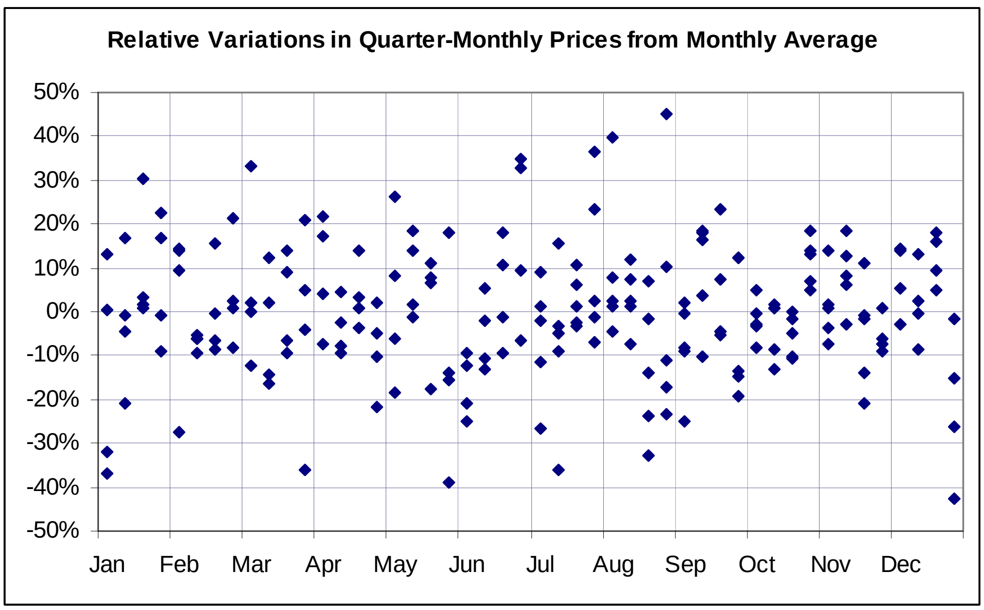
Monthly Average All-Hours Energy Prices for NY-North

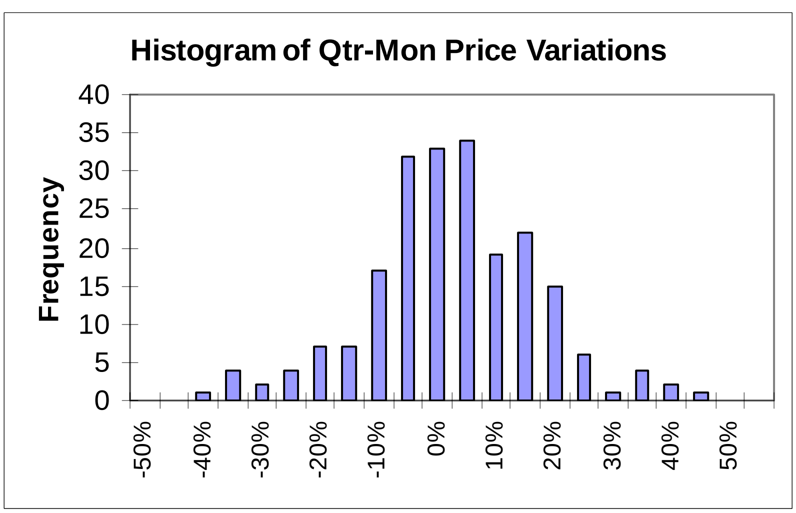
Month	2000	2001	2002	2003	2004	Average	StDev	StDev/Avg
Jan		39.5	23.0	48.9	61.1	43.1	12.4	29%
Feb		32.2	21.5	64.8	47.0	41.4	14.6	35%
Mar		38.5	22.4	61.2	44.2	41.6	12.4	30%
Apr		33.8	26.2	41.8	46.9	37.1	7.0	19%
May		33.7	17.2	38.4	47.6	34.3	9.8	29%
Jun		29.9	24.4	38.0	42.3	33.7	6.2	18%
Jul	23.2	33.1	40.0	43.8	44.5	37.0	7.3	20%
Aug	31.3	46.3	34.2	48.7	42.0	40.6	6.2	15%
Sep	38.2	31.8	38.1	41.1	42.1	38.2	3.3	9%
Oct	47.1	28.4	40.9	40.4	46.4	40.6	6.1	15%
Nov	42.9	24.3	40.8	34.0	55.3	38.2	9.4	25%
Dec	48.1	24.0	47.1	39.6		39.7	8.6	22%



This represents the variation across several years, but more appropriate for the current analysis is the quarter-monthly variation relative to a current baseline average. In the next analysis we look at how the quarter-monthly prices within each month have varied from the monthly average on a normalized percentage basis. This removes the year to year variation in the prices. Although in general the individual quarter-monthly prices tend to stay within 15% of the monthly average, there have been a few occasions in the last 4 ½ years when the quarter-monthly prices have been more than 40% above or below the month's average. The distribution is fairly symmetrical in both the positive and negative directions, but some months appear to have a greater spread than others. It also appears that the last December quarter-month is always below the monthly average, likely a holiday effect.

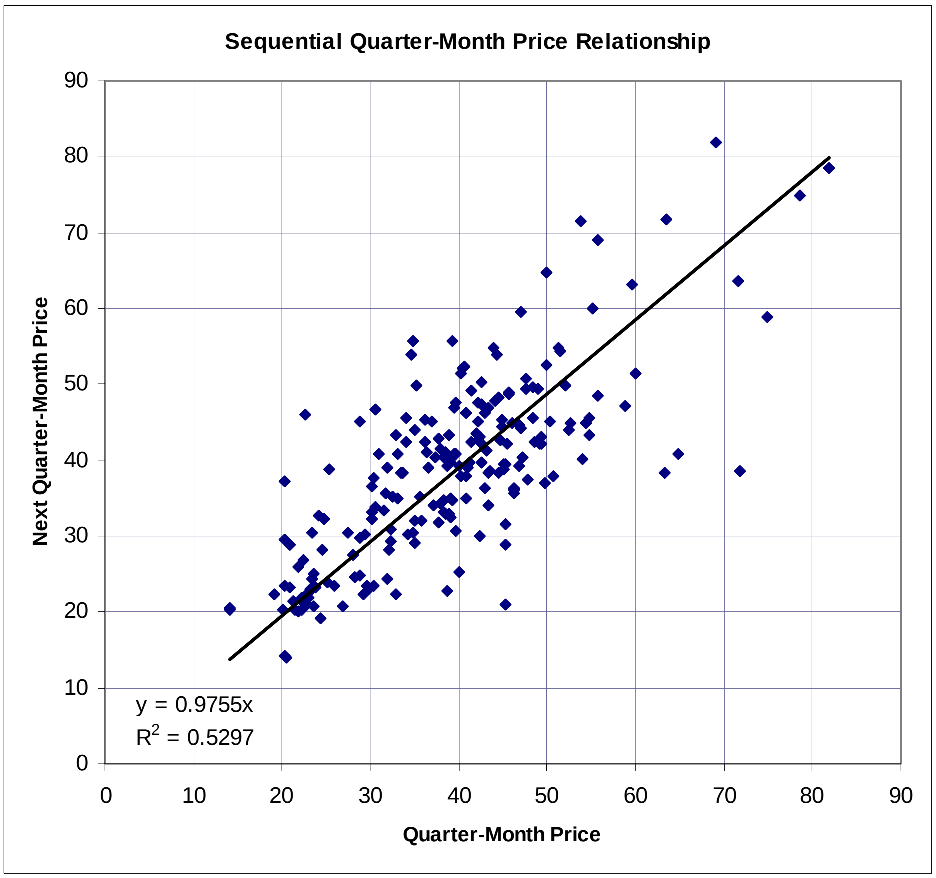
A histogram of this distribution is given in the second graph. Looking at the entire data series, the average of the variations is, as expected, zero and the standard deviation is 14.6%. Thus from an average expected monthly price one could use these parameters to generate a random series of quarter-monthly price variations from a baseline average. Thus for example one could take the quarter-monthly prices given in the short-term forecast and apply these variations using a Monte-Carlo approach to evaluate the possible effects of alternative operating rules under uncertainty.





An alternative way of representing the statistical uncertainty of quarter-monthly prices is to look at the variations from period to period as if it were a Markov process. This has the advantage of representing the temporal correlation of prices. The following scatter plot shows that there is a fairly strong relationship between sequential prices.

The mean of this distribution is effectively zero with a standard deviation of 8.28 $/MWh. From this information and the underlying quarter-month average price trends, a Monte Carlo process could be used in the river system modeling to simulate various price series. Other more sophisticated statistical approaches could be investigated, but are probably not needed for the present purpose.



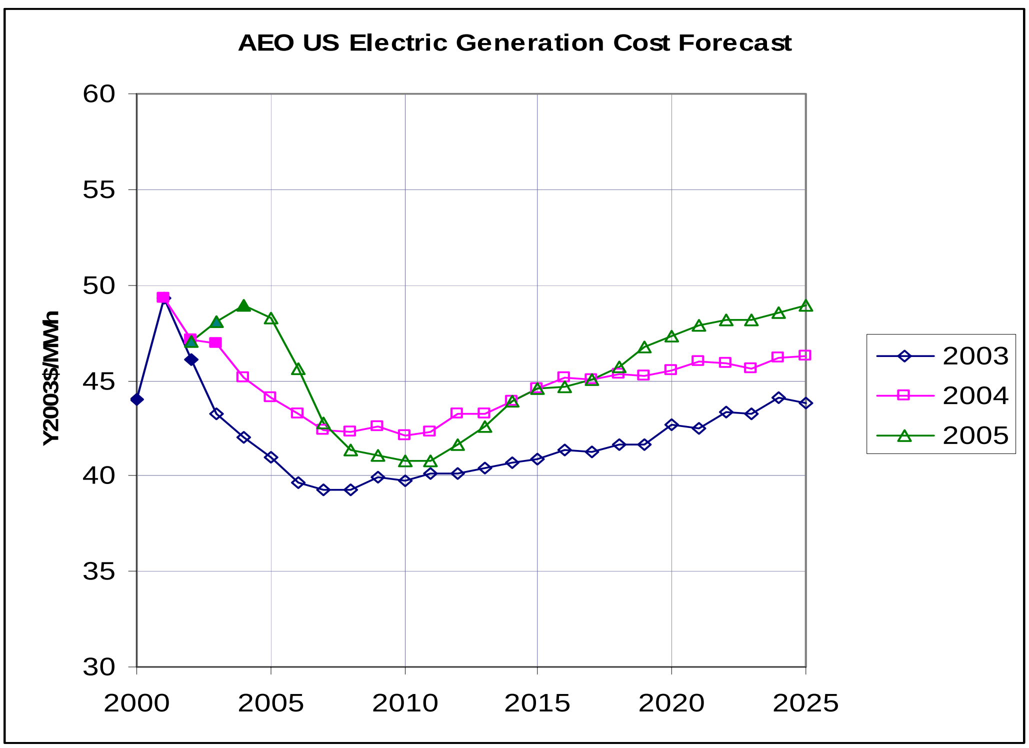
Appendix I – Long-Term Forecasting

As discussed in Appendix G, the standard peak period "5x16" represents sixteen morning through evening hours for the five workdays of Monday through Friday and includes some low-priced early and late hours. Nevertheless, the average energy price during the peak period is almost invariably greater than for the off-peak period or the all-hours average. Relative peak period prices tend to be greater during the summer because of air conditioning loads.

Primary factors affecting future long-term electricity prices:

- Fuel Prices
- Technology
- Environmental Factors
- Electricity Demand

A starting point for long-term energy forecasting in North America is the Annual Energy Outlook (AEO) produced by the US Energy Information Agency (EIA). The following graph shows the national average electrical generation (wholesale equivalent) cost forecasts for the last three years. The solid points represent historical actual costs based on full or partial year data. These forecasts are consistent in predicting a substantial reduction in prices four years in the future, with a long-term rise commencing about 2010. Note the very substantial differences in 2025 prices from these forecasts of three successive years. Also of interest is that the average real rate of cost increase after 2015 is 0.94%.



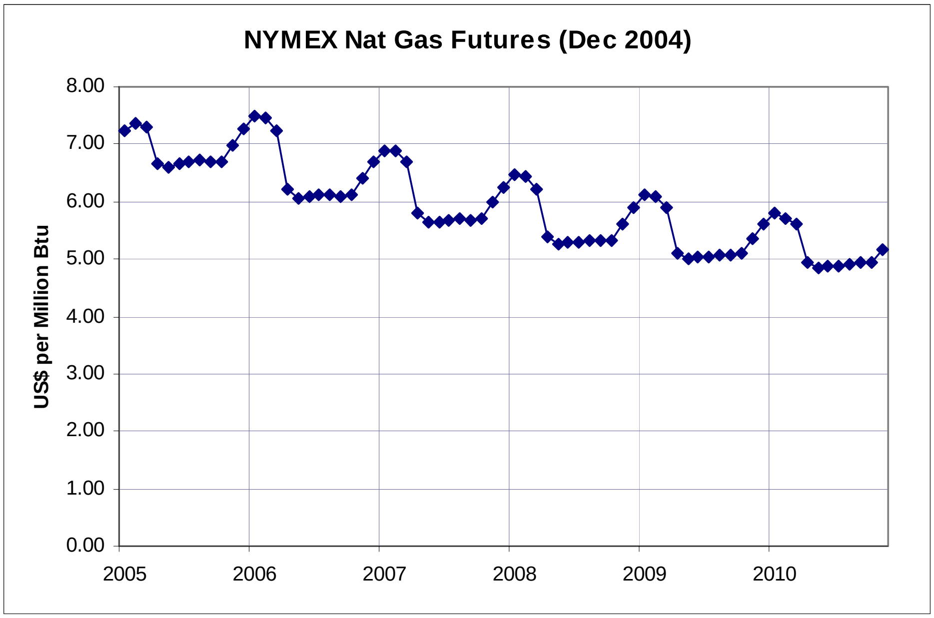
The primary factor underlying the recent high electricity prices and the prediction of a subsequent decline is natural gas prices. The table below provides some relative comparison of the natural gas prices used in the most recent AEO. The real price of natural gas used for electricity generation has risen substantially in recent years, and some decline is expected by most market observers. However a falloff in real prices of 27% by 2010 seems extremely optimistic considering the current state of natural gas reserves and discoveries in North America.

US Average Nat Gas Prices for Elec Gen

Year	Y2003$/mmBtu	%Diff'04
2002	3.686	-37%
2003	5.459	-6%
2004	5.812	0%
2005	5.881	1%
2006	5.165	-11%
2007	4.727	-19%
2008	4.353	-25%
2009	4.269	-27%
2010	4.219	-27%

From AEO 2005 (Early Release)

A decline in natural gas prices post 2005 is also shown in the recent NYMEX futures data for Henry Hub as plotted in the following graph.[17] The decline in the average annual price from 2005 to 2010 is 25% and consistent with the change in the previous table.



[17] Price data from NYMEX on 12/16/2004.

Another view of future natural gas prices is presented in the 2003 study of natural gas policy by the National Petroleum Council[18]. On page 11 of the executive summary that report states:

> **Range of Potential Prices**
>
> Supply and demand will balance at a higher range of prices than historical levels. That price range will be primarily driven by demand response through efficiency and fuel flexibility, the ability to increase conventional and nonconventional supply from North America including the Arctic, and increasing access to world resources through LNG. Price ranges for the alternate scenarios are illustrated in Figure 6. These are not status quo scenarios. They both require significant initiative by policy makers and industry stakeholders to implement the recommendations of this report in order to achieve a balanced future.

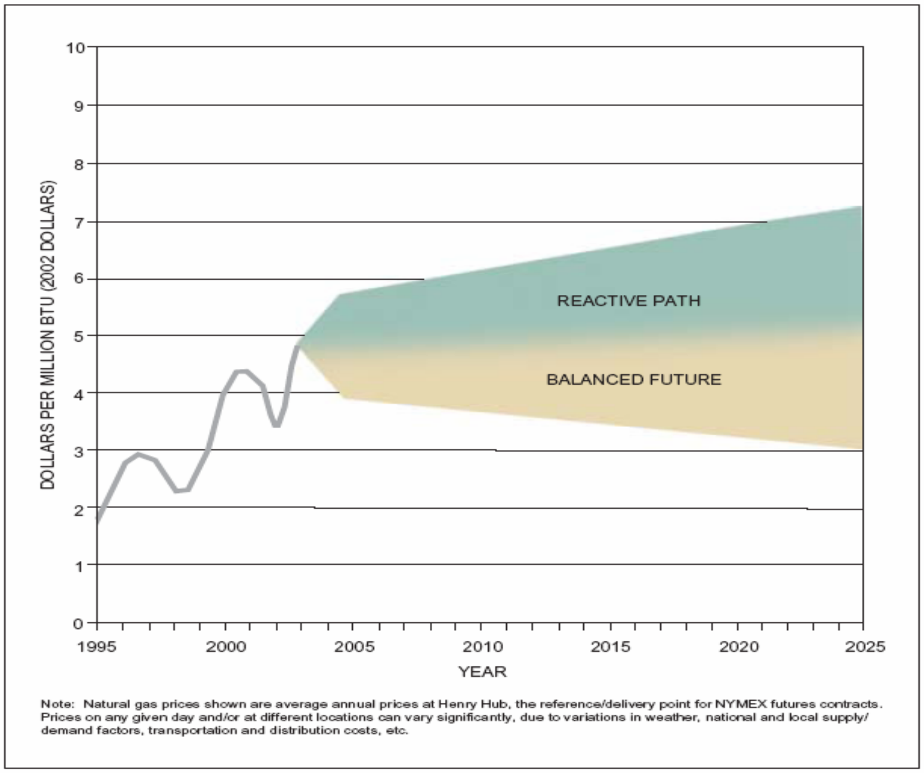


Figure 6. Average Annual Henry Hub Prices

We are now at the start of 2005, and Henry Hub Futures prices for the coming year are just a little below $7 per million Btu in nominal dollars, or the equivalent of about $6.5 in 2002 dollars as used in the above graph. However, the point we wish to make here is that this study expects no decline in natural gas prices without substantial policy efforts as indicated in their "Balanced Future" plan that includes substantial conservation and new supply initiatives. While all that may happen at some future date, it does not seem very likely any time soon.

Our view for this study is that some decline in natural gas prices are likely over the next five years but that they are likely to be fairly modest. Also, after that decline, we expect there will be modest increases in the real price of natural gas as resources become more depleted.

[18] "Balancing Natural Gas Policy – Fueling the Demands of a Growing Economy", National Petroleum Council, September 2003.

The methodology used was to take the future generating technologies as described in the AEO 2004 documentation and combine that with projections of fossil fuel prices and environmental costs (including carbon) to arrive at the least cost marginal generation mix based on dispatchable resources. We consider that most renewable resources such as wind, solar and hydro will be price takers. Thus marginal prices will be essentially determined by various mixes of natural gas and coal burning technologies. The table below gives some of the key input assumptions for the three cases.

Key Assumptions for Long Range Forecasts

Mid Case					
Future Prices		2005	2010	2020	2030
Nat Gas	$/MBtu	5.923	5.331	5.864	6.450
Steam Coal	$/MBtu	1.835	1.835	1.890	1.946
NOx Cost	$/Ton	3,500	4,000	4,500	5,000
SOx Cost	$/Ton	640	800	1,000	1,000
CO2 Cost	$/Ton	0	5	10	15
Low Case					
Future Prices		2005	2010	2020	2030
Nat Gas	$/MBtu	5.923	4.428	5.192	5.573
Steam Coal	$/MBtu	1.835	1.669	1.646	1.624
NOx Cost	$/Ton	3,500	4,000	4,000	4,000
SOx Cost	$/Ton	640	800	800	800
CO2 Cost	$/Ton	0	5	10	15
High Case					
Future Prices		2005	2010	2020	2030
Nat Gas	$/MBtu	5.923	6.219	6.841	7.525
Steam Coal	$/MBtu	1.835	1.926	2.023	2.124
NOx Cost	$/Ton	3,500	5,000	5,500	6,000
SOx Cost	$/Ton	640	900	1,100	1,300
CO2 Cost	$/Ton	0	5	15	25

Costs are expressed in constant 2003 US$.

The full cost of new generation includes investment costs as well as variable costs. For the purposes of this analysis we have assumed that there is a capacity market (or some other form of compensation) for the value of capacity based on a proxy capacity-only resource such as a combustion turbine. Capacity costs above that level, depending on the technology, are then recovered in the energy prices. Another way of stating this is that energy prices need to be high enough for new generating capacity to recover their full costs or they will not be built. This of course assumes equilibrium and situations may occur in real markets with over or under capacity where prices differ and are out of balance.

The forecast for New York includes a modest decline to 2010 based on expectations of a decline in natural gas prices. The Ontario forecast because of the proposed phase-out of existing coal plants and the need to provide new capacity predicts level and rising prices. The Quebec forecast is flat until 2010 and then increases at the same rate as the Ontario prices. Note that the cost of new wind and hydro resources are likely to increase in the future as new facilities are located at less desirable sites.

Appendix J – Canada's Kyoto Implementation Plan[19]

Canada signed the Kyoto Protocol in 1998, and ratified it in 2002. With the recent ratification of the Kyoto Protocol by Russia, the Protocol will come into force in early 2005. Since 1998, Canada has been working toward a National Implementation Strategy to meet the goals of the Protocol. The National Implementation Strategy is a broad framework outlining the ways in which Canada's various forms of government will work together to address climate change. An annual National Business Plan will be produced each year to outline objectives for priority areas, as well as actions underway or under consideration by the various forms of government.

Canada's Kyoto commitments will require it to reduce greenhouse gas emissions to a level 6% below the 1990 baseline. Canada's First Ministers (the cabinet level ministers) directed federal, provincial and territorial energy and environment ministers to examine the consequences and options for complying with the Kyoto Protocol. The Energy and Environment Ministers subsequently formed the National Climate Change Process (NCCP or the National Process). Under the National Process, 450 experts from industry, academia, non-governmental organizations and government formed 15 Issue Tables/Working Groups that reviewed seven key sectors of the economy and eight cross-cutting strategies. An analysis and modeling group used the results of that review to perform a preliminary analysis of the implications of options for meeting the Kyoto requirements.

The National Implementation Strategy, as it is currently available is just 44 pages long and is essentially a tool to determine whether Canada should even sign the Kyoto Protocol. Now that Canada has signed the Protocol and it has come into force, Canada shifts into Phase II: actions to meet the compliance deadline of 2008.

Those actions include a myriad of government programs and mandates, many on the provincial level. There is, however, a clear recognition that a broad policy instrument will be necessary to make serious progress towards meeting the Kyoto requirements. The consensus appears to be that that policy instrument would be some form of a domestic emissions trading scheme. Such a trading scheme could take two forms. The first would require "upstream" producers (refineries, cement producers, etc.) to hold permits equivalent to the greenhouse gas emissions resulting from the products they sell. The approach seems to have the least impact on both national GDP and the GDP of each province[20]; however, the approach only works because of an expected increase in consumer prices which drives down demand (a 6% increase in electricity prices and a 2% increase in gas and oil prices). The second form is much more similar to existing emissions trading schemes in the U.S. Large final emitters would have to hold permits from the government in a number sufficient to cover their emissions. Such a scheme controls a much smaller share of Canada's total greenhouse gas emissions (about 40%) largely because transportation cannot be included in a final emitters trading scheme. Modeling by the National Climate Change Process showed that such a scheme would have a negative impact on both national GDP and that of all provinces. The NCCP expects less negative impact if emitters can buy allowances outside the trading system (internationally for example) or if the government is allowed to auction off allowances rather than hand them out for free.

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[19] Prepared by Anna Sommer of Synapse Energy Economics, 1/14/05.

[20] "A Discussion Paper on Canada's Contribution to Addressing Climate Change," http://www.nccp.ca/NCCP/national_stakeholders/pdf/federal_discussion_e.pdf, 2002, page 25.

"A Discussion Paper on Canada's Contribution to Addressing Climate Change" modeled the economic impacts of such a final emitters scheme supplemented with targeted measures (advanced technology, etc.) and purchase of international permits.[21] The provinces' GDP was projected to be -0.5 to -1.5% below business as usual GDP, though the net forecasted GDP remained positive for all provinces. Electricity prices were expected to rise about 4%.[22]

To date, economic modeling of Kyoto (including that referenced above) has focused on economy-wide impacts to GDP and other measures of economic strength and not on forecasting the price of carbon allowances. Indeed, such modeling makes an *a priori* assumption of the allowance price (either $10/tonne or $50/tonne, the risk management price). Environment Canada explains the rationale for such an approach:[23]

> Canada is generally expected to be a net purchaser of international permits, so the international carbon price is an important factor in determining our overall costs. In the analysis reported in Appendices I and II, the AMG estimated the economic impacts under two price scenarios - $10/tonne and $50/tonne in Canadian dollars (Cdn$). There is good reason to believe that the $10/tonne scenario is the more likely one. For example, in 29 recent international studies of the price of carbon only four showed estimates as high as Cdn$50. Of 12 estimates used by other countries only one was as high as Cdn$50. The average price expectation of experts from 34 international companies is under US$11. International permits are currently trading at a price of less than US$8/tonne, although it is still a very young and thin market. The World Bank has estimated that there are available emissions reduction projects in developing countries that would generate credits amounting to many times Canada's total emissions gap at a price of US$3 to $4.

The 2002 *Climate Change Plan for Canada* made it clear that Canada considered an emissions trading scheme for final emitters to be the preferable choice. Canada will allocate permits to emitters involved in the trading scheme and emitters will be allowed to buy international permits to meet their additional greenhouse gas emissions. The federal government has committed to capping allowance costs at $15 per ton, though they have not specified how they will do so.

For more information about the strengths and weaknesses of various policy instruments including emissions trading see:

http://www.nrtee-trnee.ca/Publications/PDF/Report_Emissions-Options_E.pdf?52,67

Note: Environment Canada's modeling of the economic impacts of Kyoto has been updated a number of times.[24] There is now discussion about whether that modeling is accurate given some of the assumptions used. For example, it is now expected that Canada will have to reduce more emissions than previously thought. To our knowledge there is no indication of if or when the analyses will be revised.

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[21] For more information see: http://www.climatechange.gc.ca/english/publications/canadascontribution/appendix1.html and http://www.climatechange.gc.ca/english/publications/ecoimpacts/ecoimpacts.pdf (Note that the required emissions reduction in this modeling is 170 MT, 70 MT less than in the Discussion Paper. Projections of energy prices and GDP in this modeling should be taken as indicative of trends but not actual forecasts.

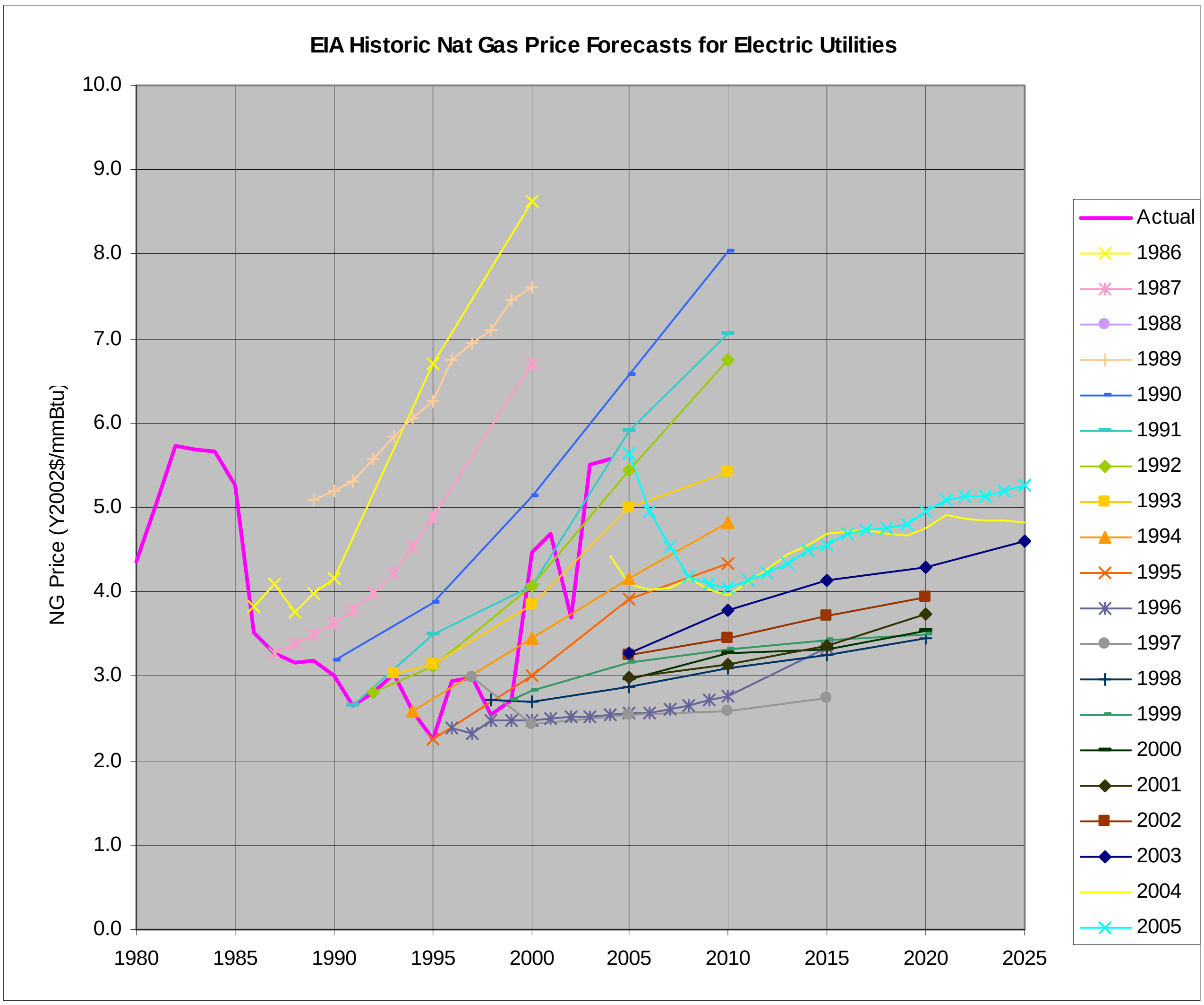
[22] "A Discussion Paper on Canada's Contribution to Addressing Climate Change," http://www.nccp.ca/NCCP/national_stakeholders/pdf/federal_discussion_e.pdf, 2002, page 33

[23] http://www.climatechange.gc.ca/english/publications/canadascontribution/concluded.html.

[24] See http://www.climatechange.gc.ca/english/publications/ecoimpacts/ecoimpacts.pdf.

Appendix K – The Uncertainty of Long Term Forecasting

The figure below shows the historic forecasts of future natural gas prices for electric generation in the US from the EIA since 1986. The actual prices up through 2003 are shown by the heavy solid line without point markers. The forecasts themselves show a considerable range, even from one year to the next. The forecasts from 1986 through 1995 predicted fairly rapid price increased. Those after 1995 show instead much lower increases in NG price. More recent forecasts have started from higher base levels reflecting current prices, but still with low rates of growth. The most interesting forecast is that from the most recent AEO (2005) which takes as steep downhill approach to 2010 where it then resumes a more typical growth rate. This background should be kept in mind when relying on electric price forecasts that are driven by underlying natural gas price projections.



Appendix L – Commentary on Modeling Uncertainty

The modeling of the St. Lawrence hydroelectric operations needs to take into consideration several kinds of uncertainty:

1. Hydrologic Resources – Depending on the rainfall and other environmental factors the amount of available water can vary on an annual and seasonal basis.
2. Electric Load – Demand for electricity varies on an hourly basis. Both cold and hot weather can result in peak loads. The range of predictability for weather is generally several days.
3. Electric Market – Electricity market prices basically rise and fall in response to load. The degree of response depends on the current relationship between load levels and the available resources. Typically prices are higher during the seasonal peaks, but high prices can occur at other times of year because loads are unusually high and/or some resources are not available.
4. Fuel Prices – Much electricity generation uses fossil fuels. There is long term uncertainty about the costs of oil and natural gas, in addition both of those markets have shown fluctuations at the daily, monthly, seasonal and annual level. Furthermore long-term price trends are also uncertain with, for example, widely different views on world petroleum resources.
5. Environmental Costs – Electric generation, especially those using fossil fuels, have environmental effects which are likely to be internalized to some extent in market prices. The key future factor is carbon emissions which over a 30 year period could make coal generation totally unviable.

Thus there are a number of sources of uncertainty related to the management of the operation of the St. Lawrence hydroelectric resources. For the first two of these we have historical records which provide some quantitative measure of those uncertainties. However the effects of global warming could cause those to change. For the others we have little historical record and they depend to a large degree on human political and economic behavior.

Given these multiple sources of uncertainty, our recommended approach would be to test various sets of operational rules to find those that perform well under a wide variety of circumstances. An “optimal” solution for an normal set of conditions might fail badly if conditions are other than normal.