Report of Mitchell Rothman

Part of Evidence of Énergie Brookfield Marketing Inc.

to Régie de l'énergie

R-3648-2007

Prepared for

Énergie Brookfield Marketing Inc.

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Navigant Consulting, Inc.

1 Adelaide Street East

Toronto, Ontario M5C 2V9

www.navigantconsulting.com

NAVIGANT CONSULTING

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1. INTRODUCTION

1.1 Mitchell Rothman and Navigant Consulting

My name is Mitchell Rothman. I am a managing consultant with the consulting firm Navigant Consulting, Inc. (Navigant Consulting). Before joining Navigant Consulting, I was a consultant with several other consulting companies. Prior to that, I was for eleven years the Chief Economist of Ontario Hydro. Almost all of my consulting has been with respect to the electricity industry, including design of electricity markets, assessment of electricity markets, and electricity regulation. I have developed forecasts of wholesale electricity prices and reviewed the structure of the Québec electricity market for several clients.

I have testified as an expert witness before the Ontario Energy Board, the National Energy Board, and an Environmental Assessment Board in Ontario.

My full curriculum vita is attached to this report as Appendix A.

Navigant Consulting is an independent consulting company with over 2000 consultants. Our energy practice has over 170 energy experts. We consult to all participants in the electricity industry, including buyers, sellers, financiers, suppliers, regulators and government agencies.

Énergie Brookfield Marketing Inc. (EBMI) has engaged me, and Navigant Consulting, to address several questions surrounding the creation and disposition of the energy surplus forecast by Hydro Québec Distribution (HQD). EBMI asked me to

1. Explore the nature of the anticipated surplus,
2. Using information on the nature of the surplus, estimate its market value if sold in the available neighboring markets,
3. Suggest and analyze potential modes of its disposition, and
4. Make recommendations with respect to its disposition in order to provide the greatest value to Hydro-Québec's ratepayers.

1.2 Background

Hydro Québec Distribution (HQD) has filed its long-term supply plan (the Plan) with the Régie de l'énergie (the Régie), which has assigned it the file number R-3648-2007. Included in this filing are forecasts of supply and demand for electricity in Québec. These projections include a forecast of significant surplus of energy in 2008 and 2009.[1] The Plan is not specific about the proposed disposition of these energy surpluses.

Under Québec regulations[2], HQD is entitled to a maximum of 178.9 TWh of energy from Hydro Québec Production (HQP) every year, at a fixed price of 2.79 cents per kWh (the patrimonial or Heritage Pool amount). Demand for electricity in Québec is now over 180 TWh per year, and is forecast to remain above that level[3] for the entire period of the Plan, even taking account of the impact of programs of conservation and demand management. For demand beyond this amount, HQP sells energy and capacity to HQD on a competitive basis as one of many suppliers that can serve HQD. In these competitive sales, the value that HQP creates from the resale of energy or the reshaping of energy through the use of its reservoirs to store energy and produce it when it is more valuable is not necessarily shared with HQD's customers.

Given its responsibility to ensure continued reliability of supply, HQD needed to find other sources of electricity beyond the patrimonial amount. HQD has signed 14 supply contracts with several providers. The three most important contracts are two contracts with HQP for 3.1 and 2.2 TWh/year respectively, and a contract with TransCanada Energy for between 3.7 and 4.3 TWh/year from the Becancourt Energy Center cogeneration combined cycle gas turbine (CCGT) plant. In addition, HQD has signed contracts with several suppliers of wind energy. HQP has agreed to firm up these contracts at their reliable capacity level.

However, although the actual level of demand in 2007 was above the patrimonial amount, it was not at the forecast level. At the time of the Hydro Québec Distribution filing, the supply surplus was estimated to be 2.1 TWh in 2007, 5.6 TWh in 2008 and a further 2.9 TWh in 2009. After those years, supply and demand were forecast to be roughly in balance.[4] Because HQD is committed to the suppliers by contract, these amounts of electricity should be efficiently disposed of such that the cost of this surplus is minimized.

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[1] R-3648-2007, HQD -1, Document 1, pg. 36, Table 1.

[2] Éditeur officiel du Québec (2001): *An Act Respecting the Régie de l'énergie*, Legal Deposit, Bibliothèque nationale du Québec.

[3] R-3648-2007, HQD -1, Document 1, pg. 36, Table 1.

[4] Ibid, pg. 38 Table 1 and line 10.

As Barry Green noted in his evidence before the Régie in R-3644-2007, the disposal of surplus energy raises a number of issues. These include the mechanism for disposal and the design of the product being offered.[5] HQD's plan contains only a sketch of its plans for disposal. For 2008, it notes that if the Régie approves its application in Proceeding R-3649-2007, it will have only 1.3 TWh of surplus for disposal. It proposes to handle these either by selling through RFPs or by individual agreements with the suppliers.[6]

For 2009, HQD proposes to assess the situation with respect to the electricity markets at that time and its implications for the surplus.[7] It does not give concrete plans as to what it might do, except that it might consider again asking TCE not to provide the contracted energy or to make short term sales into the market.

The electricity HQD has contracted for has value in the electricity markets outside Québec. That value may be more or less than the amount HQD has contracted to pay for the electricity. At issue is the value it has and the best method of extracting the value for the benefit of electricity consumers in Québec.

In evaluating methods of disposal, HQD must consider both the expected revenue from the sales and the degree of risk in that revenue. In general, the more risky the method of disposal the higher the average returns. A disposal method is not optimal if another method is available which can provide either a higher expected return for the same risk, or a lower risk for the same expected return.

The plans put forward by Hydro Québec Distribution are not definitive enough to provide assurance that it will optimize (properly balance returns with risks) the value of the contracts it has.[8] This report explores the value of specific alternatives for disposal of the electricity in order to determine whether there is a definitively better way for HQD to proceed.

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[5] Barry Green, Evidence of Barry Green in the Matter of Proceeding R-3644-2007, on behalf of Fédération canadienne de l enterprise indépendente, pg. 5.

[6] R-3648-2007, HQD -1, Document 1, pg. 39, lines 20-22.

[7] Ibid, pg. 40, lines 5-6.

[8] The value of the contracts for the surplus energy will be negative if the contracted prices are above market prices. In that case, maximizing the value means minimizing the disposal costs by minimizing the amount that HQD must pay out.

2. Overview of Methodology and Approach

2.1 Valuing Electricity

How much a seller can realize for electricity depends on where and when it is sold. As demand for electricity varies over time, the cost of its production also varies. The value of electricity at any given time is the cost of producing the last increment, because that is how much an additional unit of demand would cost to produce and how much would be saved by reducing demand by one unit.

In jurisdictions with competitive electricity markets (such as operate in New England, New York and Ontario with which HQ is interconnected and in which HQP participates), this basic value is discovered in real time through the interaction of demand with the varying capability of suppliers. Real-time markets are characterized by significant market price volatility given limited elasticity of demand and supply in real time. In addition, many such jurisdictions have markets that price and settle electricity in advance of real time, typically one day ahead. Day-ahead markets also reflect the changing value of the electricity over time. Electricity prices in real-time and day-ahead markets therefore discover its value at any given time.

Futures markets or forward purchases allow buyers to avoid the price volatility of the real-time and day-ahead markets in New York and New England and the real-time market in Ontario. Future contracts are exchange traded whereas forward purchases are contracts; both buy or sell a fixed quantity at a set point in time. As such, embedded in these futures or forward prices there may be a premium that reflects the uncertainty associated with real-time prices over the contract term. The presence and magnitude of such a premium depends on market dynamics. Suppliers with generation assets desire to contract the output of their projects to provide greater revenue certainty and lower risk. Such contracts reduce financing costs and in many instances are an essential part of securing long-term financing. Buyers also desire cost certainty and may prefer such contracts rather than being exposed to real-time prices.

The basic value of electricity is also determined by where it is available. Electricity can only be used if it can be transported from its point of generation to its point of consumption. Transporting electricity requires a system of wires and associated equipment which have finite capacity. If cheap electricity is not able to be transported to a location where its value is high, then it must be valued in the places where it can be consumed and it will have a lower value.

Both of these basic elements of electricity's value change rapidly over time and cannot be forecasted accurately. Both buyers and sellers, therefore, face risks in electricity markets. These risks can be mitigated by contractual arrangements that set prices in advance of their discovery on the markets. The variety of such arrangements is limited only by the imagination of the buyers and sellers and the practicalities of the electricity delivery system.

Electricity products commonly traded include:

- Baseload energy, a fixed amount for 7 days a week, 24 hours a day, often over a month;
- Peak energy, a fixed amount for 5 days a week, 16 hours a day; and
- Off-peak energy, a fixed amount for 5 days a week for the 8 off-peak hours a day and during weekends and holidays for 24 hours a day.

Other products are also traded, but are not as common.

These can be traded on various markets:

- Any of the above forms can be traded in over the counter (OTC) markets;
- Futures for peak and off-peak standard blocks are traded or cleared on commodity exchanges, such as the New York Mercantile Exchange (NYMEX); and
- Bilateral contract blocks of power, configured to meet the specific needs of a buyer or seller, are usually negotiated individually between buyers and sellers.

In such contractual arrangements, the characteristics of the electricity on offer determine its price. These characteristics include:

- When the electricity is available;
- Where it is available; and
- How reliable its availability is (e.g., is it contingent on the availability of a generating unit).

2.2 Valuing the HQD Surplus

Our analysis for this project will estimate this basic value for the surplus electricity expected by HQD.

Surplus electricity contracted by HQD often has little value in the province of Québec; it usually must be delivered to markets or jurisdictions outside Québec. HQD supplies virtually all customers in the province; if its customers do not need the electricity, then there are no other customers who can take it. For example, if the surplus electricity were sold to a large industrial customer in Québec, it would simply displace the electricity that the customer would otherwise have bought from HQD, leaving HQD with exactly the same surplus position.[9]

Markets for the surplus must therefore be sought outside the province of Québec. The value of the surplus electricity is its value in the most favourable such export market. As shown in Table 2.1, Québec has electrical connections with four external jurisdictions: New Brunswick, New

[9] This would not be true if such a sale were to displace electricity that the customer would otherwise generate for itself, as for example if it had its own cogeneration facilities. However, in general such customers operate their facilities to meet their operational needs, and would not shut their facilities down in favour of purchased electricity.

England, New York and Ontario. The actual transfer capability of these interconnections is often less than indicated given system reliability considerations.

Table 2.1: Total Export Capacity with Neighbouring Jurisdictions

External Jurisdictions	Export Capacity (MW)
New Brunswick	1,200
Ontario	1,295
New England	2,305
New York	2,125
Total	**6,925**

As of December 31, 2006[10]

All of these have markets that are open at least in part to competition. New England and New York have fully competitive wholesale markets with locational pricing. Ontario has a fully competitive wholesale market with uniform pricing. New Brunswick's market is much more circumscribed. New Brunswick can also be used to access the Nova Scotia, PEI and New England markets, but such transactions may be subject to transmission constraints and additional transmission charges.

2.3 Identifying and Valuing the Surplus

The time of availability of the surplus is critical to its value. The amount of the surplus is generated by the interaction between the amount of electricity coming from Hydro Québec Production as the patrimonial amount, the amounts of electricity contracted by HQD, and the ever-changing level of demand. To establish the time of the surplus, Navigant Consulting has largely relied on HQD's estimates of monthly surpluses, but adjusted them to take into account the suspension of the TCE contract in 2008, and underestimation of both sales and purchases in months that are close to being in balance. Availability by time of day was analyzed by examining the hourly history of differences between the amount of electricity supplied to HQD by HQP and the 8,760 hourly blocks available under the Heritage Pool Contract.

For valuation, we used two methods to estimate future prices: NYMEX futures prices for electricity in NYISO and ISO-NE, and NYMEX futures price for gas multiplied by historical market heat rates. Both methods give similar values, but the first method provides prices only for some years, and for the most part only as annual average prices, while the second method

[10] Hydro- Québec TransEnergie Website, http://www.hydroquebec.com/transenergie/en/reseau/bref.html), accessed March 11, 2008.

provides monthly prices. Prices were adjusted to reflect the costs of accessing the NYISO and ISO-NE markets.

To be valued in New York or New England, the electricity must be able to be delivered there. As part of this value estimate, therefore, we have analyzed data on the availability of transmission capacity between Québec and New York and New England. These data indicate the degree to which existing transmission reservations would prevent HQD or its agent from using these facilities to access these markets.

3. Identification of Surplus Power

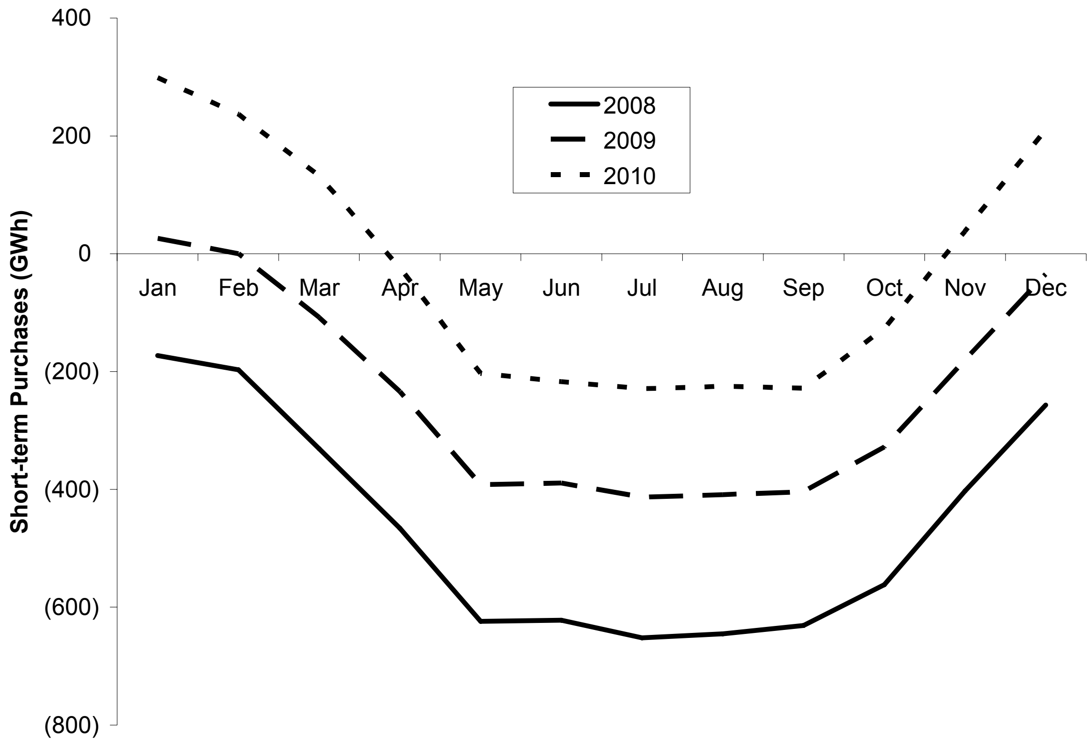
3.1 Estimated Sales by Month

In the Supply Plan[11], HQD estimates the short-term purchases and sales that will be required in each month of 2008 to 2010. These estimates are reproduced in Table 3.1 and Figure 3.1. Negative values represent sales.

Table 3.1: HQD Expected Short-Term Purchases and Sales By Month

(GWh)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
2008	(173)	(197)	(331)	(466)	(624)	(622)	(652)	(645)	(631)	(562)	(403)	(257)	**(5,563)**
2009	26	0	(108)	(234)	(392)	(389)	(413)	(409)	(404)	(328)	(180)	(35)	**(2,866)**
2010	299	237	132	(24)	(203)	(217)	(229)	(225)	(228)	(127)	38	211	**(336)**

Figure 3.1: HQD Expected Short-Term Purchases and Sales By Month



[11] R-3648-2007, HQD-2, Document 2, Annex 5A, pg. 237-239, Charts 5A-7 to 5A-9.

The annual totals match the "Additional Supply Required/Surplus" line of Table 5.1 of the Supply Plan[12] to the degree of precision shown in that table.

In response to EBMI's information request, question 2.2[13], HQD provided an estimate of expected short-term purchases and sales in 2008-2011. This is reproduced in Table 3.2[14].

Table 3.2: HQD Expected Short-Term Purchases and Sales by Year

(TWh)	2008*	2009	2010	2011
Additional Supply Required	**(5.6)**	**(2.9)**	**(0.3)**	**(0.1)**
Short-Term Purchases	0.0	0.1	1.0	1.2
Sales	5.6	3.0	1.3	1.3

*Including contract with TransCanada Energy.

In Table 3.3, short-term purchases and sales for 2008, 2009 and 2010 are compared to the sum of positive and negative short-term "purchases" shown in Table 3.1, with the sum of the positive numbers (i.e., months with net purchases), shown in the third row and the sum of the negative numbers (i.e., months with net sales), shown in the fourth (bottom) row.

Table 3.3: Purchases and Sales vs Positive and Negative Months

(TWh)	2008*	2009	2010
From Table 3.2			
Short-Term Purchases	0.0	0.1	1.0
Sales	5.6	3.0	1.3
From Table 3.1			
Sum of Positive Months	0.00	0.03	0.92
Sum of Negative Months	(5.56)	(2.89)	(1.25)

It is evident from this comparison that there is little room in HQD's estimates for purchases and sales occurring in the same month. These amount to approximately 0.1 TWh in each of 2009 and 2010.

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[12] R-3648-2007, HQD-2, Document 1, pg. 36, Table 5-1.

[13] R-3648-2007, Demande de Renseignments No 1d'EBMI au Distributeur , pg. 2.

[14] R-3648-2007, HQD-3, Document 4, pg. 6.

Evidence shows that this assumption may understate total sales. In its response to the Régie's request for information, Question 28.1[15], HQD provides a monthly accounting of short-term purchases and sales in 2007[16]. This is summarized in Table 3.4.

Table 3.4: Short-Term Purchases and Sales in 2007 by Month

(GWh)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total*
Short-Term Purchases	118	387	180	0	0	12	4	0	3	0	61	884	**1,772**
Sales	0	0	255	446	296	432	458	461	400	350	211	118	**3,427**

*Total Short-Term Purchases exceeds the sum of monthly quantities because it includes purchases under the Entente-Cadre, which are calculated after the fact.

Most months show either purchases or sales (except for minimal quantities), but three months (March, November and December) show significant quantities of both. Purchases offset by sales in the same month amounted to 378 GWh (0.4 TWh) in 2007, significantly more than the approximately 0.1 TWh (100 GWh) assumed in HQD's forecasts for future years. This difference of ~0.3 TWh/year amounts to 12% of expected sales over 2008-2011. We have no data on which to base an exact calculation of these additional gross sales in 2008-2011, but this evidence suggests that the HQD estimates understate the volume of electricity available for resale, and therefore the value of this resource.

The volumes of purchases and sales for 2008 shown in Tables 3.1, 3.2 and 3.3 are all based on the continuation of HQD's contract with TransCanada Energy (TCE) for the Becancour plant. HQD has reached an agreement with TCE to suspend operation of that plant for 2008. According to HQD's response to EBMI's information request Question 2.3[17], this will reduce HQD's surplus for the year by approximately 4.3 TWh, to 1.3 TWh, resulting in short-term purchases of 0.56 TWh and sales of 1.8 TWh[18].

I have re-estimated monthly sales for 2008-2010, and added monthly estimates for 2011, based on the following adjustments:

- reduction of the surplus for 2008 by 4.3 TWh
- offsetting purchases and sales in months when the net volume is close to zero
- continuation of the same seasonal pattern shown in Figure 3.1 into 2011.

My estimates are shown in Table 3.5. These form the basis for my calculations of the values of expected sales in the next chapter.

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[15] R-3648-2007, Demande de Renseignments No 1 de la Régie au Distributeur , pg. 18.

[16] R-3648-2007, HQD-3, Document 1, Annex 5, pg. 3-4.

[17] R-3648-2007, Demande de Renseignments No 1d'EBMI au Distributeur , pg. 2.

[18] R-3648-2007, HQD-3, Document 4, pg. 6.

Table 3.5: Revised Estimates of Sales by Month

(GWh)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
2008	0	6	117	207	280	285	294	290	289	249	175	43	**2,235**
2009	0	0	108	234	392	389	413	409	404	328	180	35	**2,892**
2010	0	0	0	24	203	217	229	225	228	127	0	0	**1,253**
2011	0	0	0	152	243	251	256	254	256	204	92	0	**1,707**

The above sales are based on HQD's load forecast, which shows a significant increase in demand in 2009 and continued growth in the following years, despite a decline in demand in 2008.[19] In response to EBMI's information request, HQD cited projects in the mining and metals sectors, particularly Alcan's project, and an expectation that it would add Papier Masson to its distribution network.[20]

This answer suggests that HQD's load forecast assumes that recent industrial load losses in Québec will not be sustained. However, the pulp and paper sector has experienced significant declines in industrial load as a result of both permanent and temporary mill closings.[21] There is a significant risk of continued deterioration in this sector. AbitibiBowater indicated in late November 2007: "Given the specific pressures in Eastern Canada relative to wood availability, energy and labor, a second phase of closures could take place by mid-2008."[22] (Québec has the highest concentration of AbitibiBowater mills in Eastern Canada.[23]) The economic forces that are contributing to the closing of these mills are largely structural, not cyclical. They include: (1) a high Canadian dollar which puts these mills at a competitive disadvantage relative to US mills; and (2) high delivered fibre costs. Two cyclical factors, the increasing prospect of a recession in the US and significant weakness in the US housing sector, which will adversely affect the wood products sector, suggest that market fundamentals aren't likely to turn around and lend strength. Therefore, there is significant risk that HQD's industrial load will continue to decline or will not rebound and that its demand will continue to be lower than forecast so that the surplus will be sustained beyond 2008. I have not reflected this in my analysis of HQD's

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19 HQD-1, Document 1, Table 2.3, pg. 14.

20 HWD-3, Document 4, pg. 4.

21 In late November AbitibiBowater announced Phase 1 of their Action Plan to Address Company Challenges; this included the closure of the Belgo plant in Shawinigan, Québec and the indefinite idling of the Donnacona plant. These closures are scheduled to take place in the first quarter of 2008. AbitibiBowater also plans to permanently shut down the #3 paper machine at its plant in Gatineau. In September of 2007 Kruger shut down one of its paper machines at their Wayagamack Mill in Trois-Rivieres, Québec indefinitely. In July 2007 Domtar announced that it would permanently close down its mill in Gatineau, Québec.

22 http://www.abitibibowater.com/media/latest-news.aspx?detail=true&reqid=1082781

23 http://www.abitibibowater.com/Resources/Documents/Corporate%20Overview.pdf

surplus. Therefore this forecast of the surplus may be conservative and understate the quantity of energy that HQD is likely to have available for sale.

3.2 Hourly Shape of Surplus

In estimating the value of HQD's electricity sales, it would be helpful to know not only the month in which the sales will occur, but the time of day, or at least whether most of the sales are during on-peak or off-peak hours. EMBI requested information that would have helped to address this question, in particular in its second information request, Questions 1.3, 1.4 and 1.5[24], but HQD did not provide the information requested. However, other information provided by HQD can give some insight into this question.

HQD reported that in 2006, it purchased 1.4 TWh of electricity under long-term baseload contracts and 2.4 TWh under short-term contracts (including 0.1 TWh under the entente-cadre), and re-sold 0.9 TWh, for a net purchase amount of 2.9 TWh.[25] In response to RNCREQ's and ROEÉ's joint request for information, Question 1.1[26] (as well as similar requests by other parties), HQD has supplied hourly accountings for 2005 and 2006 of purchases from all sources that were applied to meet regular demand. The total of all hourly purchase amounts for 2006, excluding purchases under the entente-cadre, comes to 2.76 TWh, which is consistent with 2.9 TWh (including purchases under the entente-cadre) shown above. It is therefore my understanding that the hourly amounts shown in R-3648-2007, HQD-3, Annexe 4, labelled Purchases ("Achats") are in fact net purchases, i.e., long-term contracts plus short-term purchases minus electricity re-sold[27].

Figure 3.2 shows the hourly distribution of these net purchases. (Times are in Eastern Standard Time with no adjustment for daylight savings time, and weekends and holidays are included.) During off-peak hours, net purchases amount to approximately 350 MW on average, while during on-peak hours, they average 265 MW, or 85 MW less. The most likely explanation, based on the information available, is that HQD sells much of its surplus electricity during on-peak hours; an average of 85 MW sold 16 hours a day for a full year amounts to 0.5 TWh, or over half of the amount sold by HQD in 2006.

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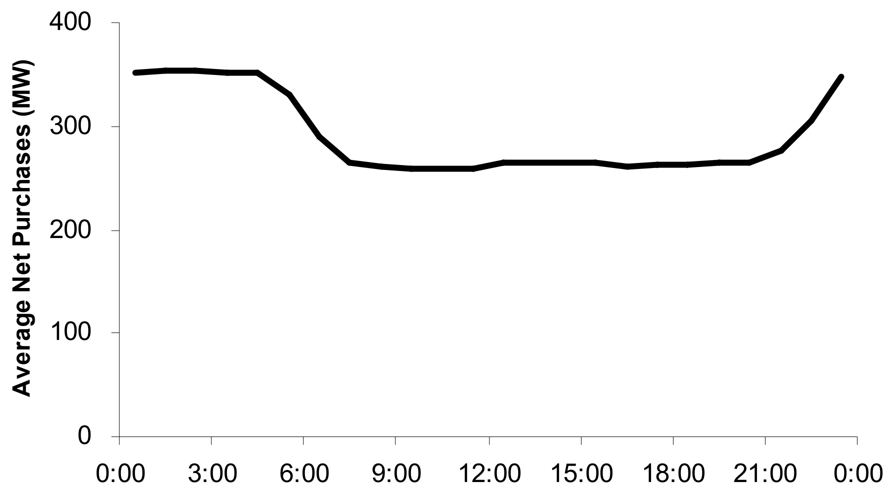
[24] R-3648-2007, Demande de Renseignments No 2 d'EMBI au Distributeur, p. 1

[25] R-3648-2007, HDQ-01, Document 2 (Annexes), p. 221.

[26] R-3648-2007, HQD-3, Document 9, p. 3-4 and Annexes 1-4.

[27] R-3648-2007, HQD-3, Document Annexes 1 to 4.

Figure 3.2: Average Net Purchases by Time of Day, 2006



Based on this analysis, it is likely that more surplus power will be available for resale in future years during on-peak hours than during off-peak hours. However, given the uncertainties, I have assumed in my analysis that there is no particular pattern of hourly availability, i.e., surplus power is equally available at all hours of the day. Given the evidence, this is a deliberately conservative assumption; that is, it is more likely to underestimate the value of the surplus energy than it is to overestimate it.

4. Value of Surplus Power

For the purpose of quantifying the value of the surplus power, I have assumed that the electricity available for resale will on average have a flat profile – i.e., it is no more likely to be available during on-peak times than off-peak times, or vice versa – so that the average market price across all hours of a month will apply to electricity sold in that month. The electricity could be sold as baseload (7x24) blocks, as combinations of on-peak and off-peak blocks, as individual hourly blocks, or in other forms. As noted, this is probably a conservative assumption because more power could be available at peak periods.

4.1 Energy Price Analysis

Two methodologies were used to estimate future electricity prices in NYISO and ISO-NE. The first was to take futures prices for each month from the NYMEX exchange, and adjust them for basis differentials[28] between the trading area on which the futures are based and the interfaces with Hydro-Québec's system. This approach is similar to that used by HQD when valuing the energy from the Becancour plant.

4.1.1 Using Future Electricity Prices

Table 4.1 summarizes futures prices for on-peak and off-peak electricity in NYISO and ISO-NE, as traded on NYMEX ClearPort between February 11 and March 10, 2008. Average prices are weighted by trade volume. The ClearPort data do not provide enough granularity to value the surplus for the out-years desired. This is evident from the gaps in this table. There were no trades for on-peak electricity to be delivered in 2010, and most of the trades for 2009, 2010 and 2011 appear to be for annual products and as such use the same price for the entire year rather than giving a separate price for each month. There were many days with no trades in any of these commodities.[29]

[28] The basis differential is the difference in value between the same commodity at two different points. It depends on transportation or other transfer costs (including congestion). The actual difference can vary from the basis differential due to market conditions.

[29] For days with no trades, NYMEX estimates an index price. Using the index prices without weighting for trade volume means relying more on NYMEX's estimates than on actual trades.

Table 4.1: NYMEX Futures Prices (US$/MWh)

		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
							On-Peak						
2008	NYISO Zone A			$73.33						$76.02			
	NYISO Zone G			$95.52									
	NYISO Zone J										$106.75	$106.75	
	ISO-NE Hub			$88.59		$91.21	$96.13	$111.88	$113.38				
2009	NYISO Zone A	$79.86	$79.86	$79.86	$79.86	$79.86	$79.86	$79.86	$79.86	$79.86	$79.86	$79.86	$79.86
	NYISO Zone G	$104.02	$104.02	$104.02	$104.02	$104.02	$104.02	$97.29	$97.29	$104.02	$104.02	$104.02	$104.02
	NYISO Zone J												
	ISO-NE Hub												
2010	NYISO Zone A												
	NYISO Zone G												
	NYISO Zone J												
	ISO-NE Hub												
2011	NYISO Zone A	$75.04	$75.04	$75.04	$75.04	$75.04	$75.04	$75.04	$75.04	$75.04	$75.04	$75.04	$75.04
	NYISO Zone G												
	NYISO Zone J												
	ISO-NE Hub												
							Off-Peak						
2008	NYISO Zone A			$53.55	$51.25	$48.33	$50.40	$56.51	$56.51	$53.75	$54.25	$54.25	$54.25
	NYISO Zone G												
	NYISO Zone J												
	ISO-NE Hub	$75.08	$75.08	$75.08	$75.08	$75.08	$75.08	$75.08	$75.08	$75.08	$75.08	$75.08	$75.08
2009	NYISO Zone A	$55.72	$55.72	$55.72	$55.72	$55.72	$55.72	$55.72	$55.72	$55.72	$55.72	$55.72	$55.72
	NYISO Zone G			$73.18	$70.96	$66.00	$68.40	$76.15	$76.15	$69.30	$70.01	$70.01	$70.01
	NYISO Zone J												
	ISO-NE Hub												
2010	NYISO Zone A												
	NYISO Zone G	$72.33	$72.33	$72.33	$72.33	$72.33	$72.33	$72.33	$72.33	$72.33	$72.33	$72.33	$72.33
	NYISO Zone J												
	ISO-NE Hub												
2011	NYISO Zone A												
	NYISO Zone G	$69.25	$69.25	$69.25	$69.25	$69.25	$69.25	$69.25	$69.25	$69.25	$69.25	$69.25	$69.25
	NYISO Zone J												
	ISO-NE Hub												

The futures prices were adjusted for basis differences to reflect prices at the Québec border. Table 4.2 shows the historical differences between prices in the zones on which futures prices are based and prices at the interfaces between the NYISO and ISO-NE systems.

Table 4.2: Historical Basis Differences

	HQ vs Zone A	NY-ISO HQ vs Zone G	HQ vs Zone J	ISO-NE Highgate vs Hub
	On-Peak			
2004	7%	-8%	-27%	-2%
2005	7%	-12%	-28%	-4%
2006	7%	-18%	-27%	-5%
2007	2%	-24%	-30%	-4%
Average	6%	-16%	-28%	-4%
	Off-Peak			
2004	9%	-7%	-19%	-2%
2005	14%	-6%	-18%	-3%
2006	12%	-10%	-17%	-3%
2007	17%	-16%	-19%	-3%
Average	13%	-10%	-18%	-3%
	Arithmetic Average			
2004	8%	-8%	-23%	-2%
2005	10%	-10%	-23%	-4%
2006	10%	-14%	-22%	-4%
2007	9%	-20%	-25%	-4%
Average	9%	-13%	-24%	-3%

The average on-peak and off-peak basis differences were applied to the average annual futures prices shown in Table 4.1, to estimate future electricity prices at the Québec border. These are shown in Table 4.3.

Table 4.3: Futures Prices Adjusted to Québec Border ($/MWh)

	Zone A	Zone G	Zone J	ISO-NE
		On-Peak		
2008	$80.22	$87.89	$78.36	$97.75
2009	$85.78	$94.68		
2010				
2011	$80.61			
		Off-Peak		
2008	$60.23			$72.88
2009	$62.95	$64.16		
2010		$65.35		
2011		$62.56		
		Average*		
2008	$69.54			$84.47
2009	$73.59	$78.39		
2010				
2011	$70.97			

* Average prices are calculated based on the number of on-peak and off-peak hours in a year. The average price for 2011 is based on the on-peak Zone A price and the off-peak Zone G price.

The results show that the prices are higher in the New England zone than in the New York zones. The range for 2008 is an average price of almost $70 per MWh in New York (for the only zone for which an average can be computed) to close to $85 per MWh in New England.

4.1.2 Using Future Gas Prices

The second methodology was based on average market heat rates, which are the ratio between electricity prices and gas prices. Both NYISO and ISO-NE are heavily dependent on gas, and their electricity prices are strongly correlated with gas prices. Future electricity prices can therefore be estimated by calculating historical average market heat rates, assuming that they will remain constant over the projection period, and applying them to gas futures prices. To the degree that these markets become more reliant on natural gas, as is likely, this assumption leads to conservative results that are likely to understate the value of the surplus.

Historical gas and electricity prices and market heat rates are shown in Table 4.4. The gas prices used are based on the Texas Eastern M-3 hub, which is located in Pennsylvania and serves new England and New York. Although other gas hubs are more directly related to electricity prices in NYISO and ISO-NE, they do not have established futures markets with adequate liquidity. As long as the basis difference between the hubs remains approximately the same in percentage terms, the specific hub used does not make a material difference.

Table 4.4: Historical Average Electricity and Gas Prices and Market Heat Rates

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Average Electricity Price @ HQ Interface with NYISO (US$/MWh)												
2004			$45.24	$47.05	$50.28	$47.01	$46.10	$42.60	$41.70	$46.34	$51.02	$53.01
2005	$61.91	$51.49	$58.06	$57.66	$53.80	$62.90	$69.99	$81.33	$99.29	$96.97	$71.39	$91.04
2006	$66.08	$60.09	$56.18	$56.55	$52.07	$53.66	$57.99	$62.55	$44.19	$48.99	$57.94	$43.54
2007	$49.92	$69.45	$59.18	$44.07	$47.74	$52.99	$55.10	$61.30	$53.54	$58.48	$59.66	$79.48
2008	$67.55	$65.50										
Average Electricity Price @ P1/P2 Interface with ISO-NE (US$/MWh)												
2004			$46.57	$51.10	$56.41	$52.58	$48.71	$45.94	$43.04	$48.75	$49.22	$57.64
2005	$67.85	$54.55	$61.02	$62.20	$56.65	$64.25	$71.17	$84.36	$99.53	$109.53	$77.77	$97.45
2006	$70.18	$66.71	$57.98	$59.04	$55.13	$56.00	$60.81	$63.67	$44.26	$51.77	$61.68	$53.84
2007	$58.23	$77.35	$66.12	$66.85	$64.26	$60.93	$59.60	$64.63	$58.27	$58.47	$61.04	$90.30
2008	$81.93	$73.12										
Average Gas Price @ Texas Easterm Zone M-3 (US$/MMBtu)												
2004			$5.88	$6.22	$6.83	$6.71	$6.33	$5.79	$5.36	$6.56	$6.44	$7.50
2005	$8.87	$6.85	$7.67	$7.70	$6.92	$7.70	$8.13	$9.99	$13.23	$14.62	$10.38	$14.02
2006	$9.39	$8.25	$7.48	$7.65	$6.70	$6.81	$6.78	$7.91	$5.32	$6.10	$7.80	$7.46
2007	$7.16	$10.07	$8.26	$8.41	$8.23	$8.00	$6.75	$6.92	$6.34	$7.13	$7.69	$8.41
2008	$10.52	$9.76										
Average Market Heat Rate - HQ-NYISO Interface (BTU/kWh)												
2004			7,692	7,562	7,365	7,005	7,284	7,363	7,784	7,063	7,928	7,064
2005	6,981	7,521	7,573	7,492	7,774	8,171	8,603	8,143	7,505	6,631	6,880	6,492
2006	7,039	7,281	7,510	7,388	7,770	7,882	8,551	7,906	8,312	8,028	7,429	5,835
2007	6,968	6,894	7,168	5,242	5,804	6,622	8,164	8,861	8,448	8,208	7,763	9,455
2008	6,422	6,714										
Average	**6,852**	**7,103**	**7,486**	**6,921**	**7,179**	**7,420**	**8,151**	**8,068**	**8,012**	**7,483**	**7,500**	**7,211**
Average Market Heat Rate - P1/P2 Interface (BTU/kWh)												
2004			7,917	8,212	8,263	7,835	7,697	7,939	8,035	7,430	7,649	7,681
2005	7,650	7,969	7,959	8,081	8,186	8,347	8,749	8,446	7,523	7,490	7,495	6,948
2006	7,475	8,083	7,750	7,713	8,228	8,225	8,968	8,047	8,325	8,485	7,910	7,216
2007	8,128	7,679	8,008	7,951	7,812	7,614	8,831	9,342	9,193	8,206	7,943	10,741
2008	7,788	7,494										
Average	**7,761**	**7,806**	**7,909**	**7,989**	**8,122**	**8,005**	**8,561**	**8,444**	**8,269**	**7,903**	**7,749**	**8,147**

Source: Energy Velocity

Table 4.5 shows NYMEX gas futures prices, and the resulting price projections based on multiplying these gas prices by the historical market heat rates. The gas futures prices are averages for trading days between February 11 and March 10, 2008, inclusive. The electricity prices are average or baseload prices. The prices are similar to those derived from futures prices.

Table 4.5: Projected Average Electricity Prices

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Average
Texas Eastern Zone M-3 Futures Price ($/MMBtu)													
2008	Actual Prices Available		$6.26	$9.91	$9.94	$9.99	$10.06	$10.12	$10.13	$10.20	$10.63	$11.59	**$9.88**
2009	$12.98	$12.79	$11.45	$9.34	$9.25	$9.30	$9.36	$9.41	$9.42	$9.49	$9.91	$10.90	**$10.30**
2010	$12.30	$12.13	$10.81	$8.99	$8.94	$8.99	$9.05	$9.10	$9.10	$9.17	$9.51	$10.48	**$9.88**
2011	$11.66	$11.71	$10.40	$8.89	$8.86	$8.92	$8.99	$9.04	$9.05	$9.12	$9.37	$10.34	**$9.70**
Projected Electricity Price @ NYISO-HQ Interface ($/MWh)													
MHR	6,852	7,103	7,486	6,921	7,179	7,420	8,151	8,068	8,012	7,483	7,500	7,211	**7,449**
2008	$67.55	$65.50	$46.86	$68.55	$71.34	$74.14	$82.02	$81.63	$81.13	$76.33	$79.69	$83.58	**$73.19**
2009	$88.97	$90.82	$85.73	$64.66	$66.41	$69.01	$76.28	$75.93	$75.47	$71.03	$74.34	$78.59	**$76.44**
2010	$84.28	$86.13	$80.95	$62.23	$64.15	$66.69	$73.75	$73.41	$72.94	$68.65	$71.30	$75.57	**$73.34**
2011	$79.89	$83.19	$77.88	$61.56	$63.64	$66.22	$73.28	$72.94	$72.51	$68.23	$70.27	$74.56	**$72.01**
Projected Electricity Price to HQD for Sales @ ISO-NE P1/P2 Interface ($/MWh)													
MHR	7,761	7,806	7,909	7,989	8,122	8,005	8,561	8,444	8,269	7,903	7,749	8,147	**8,055**
2008	$81.93	$73.12	$49.51	$79.14	$80.71	$79.98	$86.15	$85.43	$83.73	$80.62	$82.33	$94.43	**$79.76**
2009	$100.77	$99.82	$90.58	$74.64	$75.14	$74.45	$80.12	$79.46	$77.89	$75.02	$76.81	$88.78	**$82.79**
2010	$95.45	$94.66	$85.53	$71.83	$72.58	$71.95	$77.46	$76.82	$75.28	$72.50	$73.67	$85.37	**$79.43**
2011	$90.47	$91.44	$82.29	$71.07	$72.00	$71.45	$76.97	$76.33	$74.83	$72.06	$72.60	$84.23	**$77.98**

The price that HQD can expect to receive is less than this, because of three factors:

- HQD will be charged for transmission losses on HQT's system, at a rate of 5.2%. However, because of the way transmission costs are determined in Québec, the volume of electricity sold by HQD is not expected to materially change the transmission charges it pays. This is confirmed by HQD in its submission under R-3649-2007, HQD-2, Document 2, Appendices, p. 14.
- Brokerage fees and reservation fees on NYISO's or ISO-NE's systems. In its response to ACEF's information request, Question 28, HQD notes that it is charged $0.75/MWh by its broker for transactions on the DAM. In its submission under R-3649-2007, HQD-2, Document 2, Appendices, p. 13, brokerage fees combined with reservation fees on the New York system are estimated to amount to $0.91/MWh. Fees for other types of sales, such as bilateral contracts and RFPs, are likely to be much lower, but the price received may include a discount on the expected market price. The estimate of $0.91 is used here as no better estimate is currently available.
- Transmission congestion. There may be times when the buyer of HQD's surplus electricity is unable to access the NYISO and ISO-NE markets because the interfaces are already being used at or near their capacity. Table 4.6 shows the average Day-Ahead price at the HQ interfaces with NYISO and ISO-NE at all hours in each month of 2007, and during only those hours when there was more than 300 MW of spare capacity on the line. The differences between these prices reflects the lower price that HQD may receive if it can only sell its surplus electricity during uncongested hours. This is a very conservative estimate, in that the buyer of the electricity is likely to be able to obtain at least some transmission capacity even during hours when the transmission lines are near capacity.

Table 4.6: Potential Losses due to Congestion ($/MWh)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Average
						NYISO							
All Hours	$49.91	$69.44	$59.12	$44.12	$47.76	$52.95	$55.14	$61.27	$53.51	$58.51	$59.68	$79.49	$57.58
Uncongested	$48.54	$69.18	$56.70	$41.91	$46.11	$51.77	$53.65	$58.87	$53.37	$58.58	$54.45	$79.49	$56.05
Congestion Loss	$1.37	$0.26	$2.41	$2.22	$1.64	$1.18	$1.50	$2.40	$0.14	($0.07)	$5.23	$0.00	$1.52
						ISO-NE							
All Hours	$58.23	$77.35	$66.03	$66.85	$64.26	$60.91	$59.62	$64.60	$58.25	$58.50	$61.13	$90.30	$65.50
Uncongested	$44.39	$56.67	$60.51	$64.57	$58.04	$52.10	$55.41	$58.33	$57.07	$58.30	$53.39	$78.36	$58.10
Congestion Loss	$13.84	$20.68	$5.52	$2.28	$6.22	$8.81	$4.21	$6.27	$1.19	$0.20	$7.74	$11.94	$7.41

The prices that HQD could expect to receive for baseload sales on the DAM, after making these adjustments, are shown in Table 4.7. The actual price that HQD would receive could vary from these estimates for several reasons:

- Market prices could change, including gas prices, gas price basis differences between Texas Eastern M-3 Hub and the NYISO and ISO-NE markets, market heat rates within NYISO and ISO-NE, and electricity price basis differences between the main NYISO and ISO-NE markets and their interfaces with HQD.
- Charges for transmission losses and for brokerage and reservation fees could change.
- If HQD is able to sell most of its surplus electricity during on-peak hours, as was suggested at the end of Chapter 3, or to concentrate sales in days or seasons when prices are higher, the price it receives could increase.

Table 4.7: Projected Price to HQD

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Average
Projected Electricity Price to HQD for Sales @ NYISO-HQ Interface ($/MWh)													
2008	$61.93	$61.09	$41.22	$62.04	$65.26	$68.38	$75.56	$74.28	$76.07	$71.72	$69.61	$78.54	**$67.14**
2009	$82.30	$85.16	$78.17	$58.34	$60.58	$63.51	$70.10	$68.87	$70.70	$66.67	$64.52	$73.79	**$70.22**
2010	$77.83	$80.70	$73.63	$56.03	$58.42	$61.31	$67.70	$66.47	$68.29	$64.41	$61.63	$70.93	**$67.28**
2011	$73.66	$77.91	$70.71	$55.39	$57.94	$60.86	$67.25	$66.02	$67.88	$64.01	$60.65	$69.97	**$66.02**
Projected Electricity Price to HQD for Sales @ ISO-NE P1/P2 Interface ($/MWh)													
2008	$63.13	$47.91	$40.63	$72.04	$69.59	$66.31	$76.77	$74.02	$77.49	$75.53	$69.61	$76.91	**$67.50**
2009	$81.04	$73.29	$79.67	$67.77	$64.30	$61.05	$71.04	$68.36	$71.95	$70.21	$64.36	$71.54	**$70.38**
2010	$75.98	$68.39	$74.87	$65.09	$61.86	$58.68	$68.51	$65.84	$69.46	$67.81	$61.38	$68.30	**$67.18**
2011	$71.25	$65.33	$71.79	$64.36	$61.31	$58.20	$68.04	$65.38	$69.04	$67.39	$60.37	$67.22	**$65.81**

These prices are noticeably lower than those estimated using the electricity futures prices, but the two estimates are reasonably consistent, especially given that the electricity futures-based estimates did not explicitly adjust for congestion within the selling jurisdiction. Given the sparseness of the electricity futures market data, and again making the value estimate conservative, I based my estimate of the potential revenue on the gas-futures prices.

4.2 Estimated Revenue from Energy Sales

Table 4.8 estimates the revenue that HQD could receive if it sold all of its available surplus, as estimated in the previous chapter, in the DAM.

Table 4.8: Estimated Revenue from Sale of Surplus Electricity

	Revenue if sold at … NYISO-HQ Interface	P1/P2 Interface
$ million		
2008	$155.0	$159.1
2009	$192.3	$196.9
2010	$80.7	$81.8
2011	$107.7	$110.2
$/MWh		
2008	$69.3	$71.2
2009	$66.5	$68.1
2010	$64.4	$65.3
2011	$63.1	$64.6

Table 4.8 indicates that the annual revenues from the sale of surplus are significant and total $350 million in 2008 and 2009. This represents slightly less than 2% of HQD's annual revenue and demonstrates that the importance to HQD customers of how the surplus is disposed of and the need to optimize its value.

Table 4.8 also suggests that potential revenue is approximately the same in both the NYISO and ISO-NE markets, once congestion losses are taken into account. Prices tend to be higher in ISO-NE, but the P1/P2 and Highgate interfaces tend to be congested more frequently than the NYISO-HQ interface. However, when the transmission lines are not congested, it may be profitable to concentrate sales on the ISO-NE market.

Finally, the results of this analysis can be viewed as conservative. I have not considered the ability of HQD to optimize sales by selling into the market that offers the highest value. The values shown for the various interfaces assume that sales were just made at that interface and do not reflect the possibility of arbitraging these markets.

4.3 Capacity Sales

As noted in its response to the Régie, Question 28.2[30], HQD does not currently sell capacity, and does not intend to do so in 2008, because it would conflict with the spirit of the entente-cadre, in that it could be construed as resale of capacity provided by HQP. However, the entente-cadre expires at the end of 2008, and HQD had indicated that the possibility of capacity sales could be re-evaluated when it renegotiates this agreement.

Participation in the ISO-NE capacity market normally requires a firm commitment at least three years in advance. Capacity commitments are for a Delivery Year, which runs from June through the following May. Auctions are held approximately three years before the beginning of each Delivery Year. "Reconfiguration auctions" may be held between the initial auction and the Delivery Year, with the last one held in April just before the Delivery Year begins. Capacity can also be sold through bilateral contracts.

The amount of electricity that HQD has available for sale is the difference between its demand and its sources of supply. This is difficult to predict with any precision. It would therefore be difficult to make the kind of firm advance commitment expected in ISO-NE's capacity market.

NYISO holds three kinds of capacity auctions:

- A strip auction, for a six-month period (either May through October or November through April)
- A monthly auction, for each of the remaining months in the summer or winter periods.
- A spot auction, also for each of the remaining months in the summer or winter period.

The auctions are held as little as a week before the delivery period. For example, in the spot auction for April 2008, offers must be submitted by March 25.

Table 4.9 contains the auction results for the Hydro Québec price point for the strip and monthly auctions held since October 2006. Prices are on the order of $2/kW-month.

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[30] R-3648-2007, HQD-3, Document 1, p. 45-46.

Table 4.9: NYISO Auction Prices at the HQ Price Point ($/kW-month)

Date of Auction	Strip Auction Next 6 Months	Monthly Auction Next Month	2 Months Ahead	3 Months Ahead	4 Months Ahead	5 Months Ahead	6 Months Ahead
Oct-06	$2.50	$1.75				$2.07	$2.01
Nov-06		$2.25	$2.25	$2.25	$1.91	$1.91	
Dec-06				$1.80	$1.80		
Jan-07		$2.60	$1.80	$1.76			
Feb-07		$1.74	$1.71				
Mar-07		$1.30					
Apr-07	$2.25	$2.40	$2.18	$2.11	$2.05	$2.05	$2.05
May-07		$2.90	$2.39	$2.25	$2.19	$2.19	
Jun-07							
Jul-07							
Aug-07							
Sep-07							
Oct-07	$1.91	$1.90	$1.93	$2.01	$1.99	$1.40	$1.25
Nov-07		$1.99			$1.25	$1.25	
Dec-07							
Jan-08			$1.50	$1.48			
Feb-08		$1.50	$1.33				

As discussed in the previous chapter, it is assumed that HQD's surplus available for sale will be baseload energy, distributed equally over all hours. The amount of capacity corresponding to the surplus energy available in each month is summarized in Table 4.10, along with the capacity revenue that could be earned on the NYISO capacity market, assuming a capacity price of $2/kW-month. It might be possible to increase capacity revenues significantly by shifting some of the surplus from off-peak to peak hours.

Table 4.10: Potential NYISO Capacity Revenue

	Average UCAP (MW)	Potential Revenue ($ million)	($/MWh)
		$ million	
2008	241	$5.8	$2.59
2009	312	$7.5	$2.59
2010	135	$3.2	$2.59
2011	184	$4.4	$2.59

HQD could choose to sell capacity only in months when it had significant amounts of surplus energy. It could avoid the winter months when its own peak demand normally occurs, since these are the months when it tends to have less of a surplus available for resale. It has significant sources of supply in addition to the Heritage Pool Contract and the entente-cadre; these include Becancour, wind projects, other third-party contracts. It could commit to selling capacity without relying on the Heritage Pool Contract and the entente-cadre. Doing so would increase its revenues by approximately $5 million/year, and possibly more.

5. Modes of Disposition of Surplus

5.1 Maximizing the Value of the Surplus

HQD customers will be best served if HQD maximizes the value of the surplus within acceptable levels of risk. There are many options available to HQD for disposing of its surplus power, but they can be divided into two questions: what products to offer, and what process to use.

5.2 Product Selection

There are a number of different markets in which HQD could dispose of its surplus. These markets are differentiated in terms of products (baseload, peak/off-peak), location for delivery of the power (e.g., various NY ISO and ISO-NE zones and the Ontario market) and type of transaction (e.g., futures, forward, Day Ahead).

HQD currently offers a variety of products, including baseload, on-peak, off-peak and irregular blocks of power, but electricity is generally sold within Québec or at the Québec border, except for small amounts sold into the Day Ahead Market through an agent.

Efficient risk allocation would help to ensure that HQD receives reasonable value for the surplus. An inefficient risk allocation where buyers are bearing risks that they cannot reasonably manage will result in significant discounts to the price received. Selling standard products such as on-peak, off-peak or baseload blocks of power with standard terms and conditions increases the number of prospective buyers and better allows buyers to assess the value of the commodity, both of which are likely to increase the value received. Selling power where there are a significant number of buyers expands the potential market and the likely competitiveness of the sale.

The markets with the greatest liquidity that are readily accessible to Québec are the NYISO and ISO-NE markets. An important aspect of participating in these markets is purchasing and managing the transmission access and financial transmission rights (referred to as Transmission Congestion Contracts (TCCs) in New York) that allow a buyer to manage the risks of locational marginal pricing (LMP). In theory, the FTRs/TCCs allow the holder to hedge the risk of LMP. However, experience indicates that the markets for these FTRs/TCCs can be illiquid; can result in an excessive risk premium; and do not allow market participants to hedge transmission congestion risks over long distances.[31] While selling deeper into these markets is attractive given the higher LMPs offered, HQD clearly doesn't have the capabilities to manage the risks of such sales. Therefore, continuing to sell at the border is a reasonable alternative.

5.3 Process Selection

An appropriate approach for HQD would recognize its existing resources and capabilities and within these constraints maximize the value realized for the surplus considering the associated risks. As a distribution company, HQD doesn't have a formal trading operation like that of HQP or EBMI. Furthermore, HQD doesn't have authority from the US Federal Energy Regulatory Commission (FERC) to sell power at market-based rates in the U.S. nor is it a member or registered participant in any of its interconnected power markets. Therefore, HQD is required to sell power at the Québec border and could not optimally sell the power itself to customers in the United States.

Various other approaches could be used to dispose of HQD's surplus. The two most obvious alternatives are auctions of various designs and sales through agents. Auction designs that have been used extensively in the electricity sector include sealed bid auctions (i.e., requests for proposals) such as used by HQD to purchase long-term power supplies and dispose of surpluses, and the clock auction which was used in New Jersey for the procurement of Basic Generation Service.

Clock auctions have produced very competitive results, but have relatively high fixed costs and as such are appropriate for the sale of large blocks of power with the same attributes. This suggests that in order to use a clock auction effectively, HQD would have to dispose of most of its surplus at one time, which would value the surplus based on market conditions at that time and therefore increase overall risks.

Given the uncertainty regarding the magnitude of its surplus it is likely that HQD will have additional blocks of power available for sale over time. While HQD could use a clock auction for the initial volumes, given the smaller amount of power offered in subsequent sales a clock auction would not be appropriate for these volumes.

Requests for proposal processes are relatively easy to administer and their costs low. To be successful they must be adequately advertized, with proper notice given. While they don't

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[31] Emily S. Bartholomew, Afzal S. Siddiqui, Chris Marnay and Shmuel S. Oren, "The New York Transmission Congestion Contract Market: Is It Truly Working Efficiently?" Ernest Orlando Lawrence Berkeley National Laboratory, June 2003.

generate the same degree of competitive tension as a clock auction, they are appropriate for smaller volumes of power.

Another approach would be to sell electricity through an agent, as HQD now does when selling into the Day Ahead Market. Using an agent is fairly expensive; HQD reports that it pays brokerage fees of $0.75/MWh for sales into the DAM, and this is a simple transaction. Currently, HQD is required to use an agent for these transactions, because it is not a registered market participant in NYISO and ISO-NE. HQD has stated that it does not have the volume of transactions which could justify the expense of becoming a registered market participant in these markets[32].

[32] R-3648-2007, HQD-3, Document 1, p. 46.

6. Summary and Recommendations

HQD has forecast a significant surplus of energy produced by the Heritage Pool amount and long-term contracts relative to demand for the years 2008 to 2011. I have adjusted these amounts to account for gross sales in months likely to have both purchases and sales, resulting in an upward revision of the amounts of electricity which HQD must sell. Furthermore, as our analysis shows, there is a reasonable risk that HQD has understated the level of surplus given the potential for continued weakness in a number of industrial sectors that are HQD's largest industrial electricity users.

My analysis indicates that the market value of the surplus in 2008 and 2009 is close to $400 million, or almost 2% of HQD's annual revenue.

In this report, I have estimated the value of this surplus energy and discussed the relative merits of potential methods of its disposal. An estimate of value of this kind can help HQD to guide its disposal by setting an expectation of returns.

In my opinion, the size of this surplus, its estimated value, and the potential that it could be sustained longer than anticipated require that a systematic analytical approach be taken to its disposition. HQD should be put forward a formal plan to show how it intends to maximize the value of its surplus within acceptable levels of risk. Establishing a formal plan for the disposal of the surplus would help prospective purchasers plan for any RFPs or auctions and by so doing enhance the competitiveness of the processes and the value received.

Appendix A: CV for Mitchell Rothman

Mitchell Rothman
Managing Consultant

Navigant Consulting
2 Bloor Street West, Suite 2005
Toronto, Ontario M4W 3E2
Tel 647-288-5205
Fax 416-927-0541

mrothman@navigantconsulting.com

Education and professional

B.A. (cum laude) Economics, 1965 – Harvard University

MS Economics, 1970 – Carnegie-Mellon University

Ph.D. Program, Economics, 1971 – Carnegie-Mellon University

Employment

- Navigant Consulting
- PA Consulting, Inc/Hagler Bailly
- Canadian Energy Environmental Economics
- Acres International, Ltd.
- Ontario Hydro
- Canadian Imperial Bank of Commerce
- MPR Associates
- Faculty of Administrative Studies, York University

Professional associations

International Association for Energy Economics

Canadian Association for Business and Economics

Association of Power Producers of Ontario

Current Position

Mitchell Rothman is a Managing Consultant in Navigant Consulting's Toronto office.

(i) Professional Experience

An experienced economist and analyst for business decisions and government policy. Mr. Rothman's experience includes electricity market restructuring, regulatory testimony and support, environmental economics, energy efficiency, policy analysis, and energy economics.

Regulatory Processes and Testimony

- Preparation of material and testimony to support expert witness in damages case. Case related to damages from failure to deliver fuel for electricity generation. Damages calculations included determining the difference between costs incurred for substitute electricity or fuel used during fuel shortages and costs that would have been experienced had fuel been delivered as contracted.
- Testified as expert witness at National Energy Board hearing on application by New Brunswick on gas export licensing. Testimony included analysis of natural gas markets in Atlantic Canada and New England.
- For Enbridge Consumers Gas, advice and support for Ontario Energy Board hearing on natural gas storage rates and the possibility of forbearance. Support included analysis and report on FERC and other state practice, review of reports from other parties, and support for expert witness.
- For Enbridge Consumers Gas, review and evaluation of methodology for calculation of Total Factor Productivity, as part of preparation for and design of proposed second round PBR regime. Included attendance and presentation at stakeholder meeting.
- .Expert witness in Ontario Hydro rate hearings before

Ontario Energy Board for ten years. Testified annually to load forecasts, economic forecasts, forecasts of demand management effectiveness, and other economic matters.

- Expert witness in Ontario Hydro transmission hearings. Testified to load forecasts and other economic matters.

- Econometric analysis of marginal costs for Massachusetts utility. Included modelling and analysis of single and multiple regression models, analysis to account for multicollinearity, serial correlation, and heteroscedasticity, and final choice of recommended models for marginal cost of capacity-related capital investment, customer-related capital investment, and operations and maintenance expenses.

- Ontario Energy Board compliance function review. Review of the compliance function, including gathering and analyzing information on best practices in compliance among other regulators and making recommendations for organization and practice of OEB function.

- For Ontario Energy Board, member of design team for first round of Performance Based Regulation for electricity distribution utilities.

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Electricity Industry Organization and Restructuring

- For TransAlta, advice and analysis on potential changes in the design of the Ontario market. Important potential changes include the introduction of locational marginal pricing and day ahead market. Analysis includes likely impact of policy changes on TransAlta's operations in Ontario. Also includes attendance at stakeholder meetings to represent TransAlta.

- For several stakeholders in Nova Scotia, provided advice and assistance with respect to drafting of the Market Rules for the Nova Scotia electricity market.

- New Brunswick Market Design Committee. Project manager and lead consultant for provision of advice to the New Brunswick Market Design Committee. As the lead consultant, Navigant Consulting provided the Committee a broad range of advice, including assistance with the terms of reference and agendas, information on restructuring in other markets, preparation of issues papers and strawmen, and professional advice on the feasibility and desirability of market models, market rules, and all other aspects of market design. Advice included analysis of policies to encourage cogeneration in the restructured New Brunswick electricity market.

- Nova Scotia Electricity Marketplace Governance Committee. Project manager and lead consultant for advice to the Nova Scotia committee making recommendations to the government on the implementation of its *Energy Strategy*. Assistance has included identifying the issues and setting agenda, helping the Committee understand the issues, providing information on restructuring experience in other markets, producing issues papers and strawmen, and helping the Committee to agree on recommendations by advising on feasibility and desirability of market models. Included advice on recommendations relating to cogeneration.

- Western Australia Electricity Reform Task Force. Provided advice to the ERTF on market design to implement government policy. Helped Task Force to integrate submissions and its draft design, and modify design to be simpler and more workable in the Western Australian context. Provided briefings, strawmen, draft recommendations to Task Force.

- Ontario Energy Board Regulated Price Plan. Led working group consultations for the design of the RPP. Plan design included rate design for time of use rates associated with the installation of smart meters. Devised methodology for the RPP to meet the requirements of legislation, regulation, and Ontario government policy, including smart meter policy, and wrote manual on implementation. Assisted in supervision of quantitative analysis of price implications and setting of first prices and wrote report setting out resulting prices.

- Wrote the Foundation Paper for the Electricity Sector Issues Table, as part of the National Climate Change Process. Foundation Paper assessed the current state of the Canadian electricity industry and current trends and expectations of future directions, and set out critical issues for the Table to address in recommending ways to meet Canada's commitment under the Kyoto Protocol.

- Advice to the Government of Nova Scotia on energy strategy. Project manager and lead consultant for advice to the electricity market component of the Government of Nova Scotia's energy strategy development. Advice includes analysis of submissions to the Energy Strategy group, information on and analysis of possible directions for the Nova Scotia electricity industry, analysis of experience in other jurisdictions, identification of the lessons learned, and applications of lessons to Nova Scotia.

- Project manager for future structure, pricing and regulation of the electricity industry in the province of Newfoundland and Labrador. Produced analysis of industry and report with options for its future structure and regulation. Project considered the structure and size of the existing industry in the province, and the relative costs and benefits of potential electricity market structures.

- Member of Market Design Committee for Province of Ontario Electricity Restructuring. Committee was charged with making recommendations to the Minister for the complete design of a competitive electricity market in Ontario. The Committee considered all aspects of the design of a competitive market, including the nature of the wholesale power market, the nature and governance of the market makers, the development of the market rules, and the mitigation of market power created by generator dominance.

- Contributed to elasticity estimates for study on smart meters to determine the impact of smart meter implementation.

- Project manager for study of fuel price elasticities in Canada and design of a fuel tax regime that will reduce greenhouse gas emissions from transportation in Canada to meet the requirements of the Kyoto Protocol. This study included designing and implementing multi-stakeholder processes for development both of opinions on factual elements and of policy options.

Electricity Market Analyses

- Advise to Ontario Power Authority (OPA) on design of a Clean Energy Standard Offer Program. Included consultation with OPA and structured consideration of issues, potential approaches, and recommended standard offer conditions.
- For Toronto Hydro, research and calculation of Value of Lost Load, for use in evaluating potential investments to increase system reliability.
- Advice to the Ontario Independent Electricity System Operator on potential changes to its system of collateral support from market participants. Included analysis of cost and
- Advice to OPA on Renewable Energy Standard Offer Program. Included receiving submissions from stakeholders and making recommendations for program elements, drafting reports for OPA, quantitative analysis of impacts of potential standard offer program provisions, and advice on pros and cons of provisions.
- Project manager and main author for report on the potential for cogeneration of electricity and heat in Ontario. The report included information from industry participants, from public sources, and from internal company resources. Report analyzed data on energy end use to produce an estimate of technical potential for cogeneration in Ontario, and estimates of cogeneration costs to estimate economic potential, for cogeneration in the industrial and commercial sectors in Ontario up to 2010.
- Analyses of electricity markets in Canada for several private clients. Analyses include present and likely future path of structure and regulation, characteristics of current market participants, implications for industrial electricity customers, and implications for current and potential market participants.
- Analysis of impact on Ontario electricity market of increased interconnection to the Province of Québec. Analysis included impacts on market price, on Ontario generators, and on Ontario consumers. Testified at

Ontario Energy Board hearing into Hydro One application for leave to construct new transmission line.

- Analysis of impact on Ontario electricity market and on environmental performance of alternative treatments of Nanticoke generating station. Project used a large-scale model of the Eastern Interconnect to analyze options for Nanticoke. Analysis included determining optimal operation of Nanticoke, including decisions on emissions control investment, given expected environmental regulations in Ontario.

Energy Efficiency and Demand Management

- Study for the Ontario Power Authority on the roles of OPA and the local distribution companies in demand management and on the appropriate levels and allocation of spending. Study is ongoing.
- Study for Canadian Electricity Association, Canadian Gas Association and Natural Resources Canada on demand side management program frameworks, expenditure levels, and success measures. Study surveyed jurisdictions in Canada and the United States to determine how the programs are structured and measured and what entities should fulfil the critical roles in DSM programs.
- Study for a private client on planning, funds allocation and target setting for DSM programs. Study surveyed jurisdictions in North America with active and successful DSM programs to determine how the programs are planned, priorities and targets are set, and how funds are allocated to program areas.
- Responsible for chapter on energy efficiency for the Ontario Select Committee on Alternative Fuels, a committee of the Ontario legislature. Analysis considered barriers to energy efficiency and potential policies to overcome the barriers.
- Study on barriers to energy efficiency for the Ontario Ministry of Energy Science and Technology. Study identified and analyzed barriers and recommended immediate measures the Government of Ontario could

take to increase activity with respect to energy efficiency.

- During multi-stakeholder market design processes in New Brunswick and Nova Scotia, guided committees as they addressed energy efficiency issues. Guidance included writing issue papers to identify possible policies, creation of strawmen to help committees arrive at recommendations, and analysis for committee on impacts of recommendations.

- Responsible for Ontario Hydro studies on demand management (DSM) potential in industrial, residential and commercial electricity markets. Studies included consideration of appropriateness of program design, including screening criteria. Provided Ontario Hydro management with estimates of program effectiveness.

Energy and Environmental Economics

- Report for Hydro One on the value of energy efficiency. The report estimated the value of avoided environmental damage costs in order to determine the benefits of energy efficiency and the point at which their benefits outweigh the costs.

- Report for federal government on green power marketing in Canada, including evaluation of existing federal programs to support green power, assessment of state of green power market in Canada, recommendations to improve green power marketing in Canada and recommendations for specific changes to existing federal programs

- For Natural Resources Canada, environmental economic analysis for the study "Green Power Purchases for Federal Facilities", which analyzed electricity markets across Canada to estimate the benefits of green power purchases. The study used monetized estimates of the benefits of avoided environmental damage costs for each province and the value of hedging against fuel price increases. It also considered the potential for future cost reductions in renewables production. The Canadian government uses this study to help determine the price at which the benefits of green power exceed its cost, in order to set that as the amount it will pay under contracts to procure green power for its own facilities.

- At Ontario Hydro, responsible for estimation and regular updating of environmental damage costs from coal-fired generation. Estimates filed with National Energy Board to determine whether benefits from export of electricity from coal-fired sources brought benefits to Canada greater than its total cost.

- For the New Brunswick Market Design Committee and for the Nova Scotia Electricity Marketplace Governance Committee, wrote issues papers and led discussions on the potential for adoption of a renewables portfolio standard as part of the electricity restructuring in each province.

- Studies on economic impact of Ontario Hydro demand-side management programs in industrial, residential and commercial markets. Impacts assessed included employment and economic activity in affected industries.

- Project manager for data gathering project on load forecasts and transmission costs for all utilities in Canada. Gathered and synthesized data from Canadian provinces to produce report on and forecast of future loads and on transmission costs for better electrical interconnections in Canada as well as costs of integration of potential new generation. Included obtaining information on current and forecast load profiles.

- Responsible for all load forecasts for Ontario Hydro. Included aggregate short- and long-term forecasts, using a variety of methodologies as appropriate. Also included forecasts of impact of demand side management programs on electricity demand. For planning, transmission hearings and other purposes, produced forecasts of sub-provincial areas in Ontario. Testified at OEB rate hearings on load and economic forecasts.

- Review of forward price forecasts prepared for potential entrant into Ontario electricity market. Review included assessment of assumptions and results. Included review of assumptions on interconnections with US and with other Canadian provinces.

- Responsible for development and maintenance of load forecast and long-term macroeconomic forecast models at

Ontario Hydro. Supervised construction and revision of multi-equation econometric models.

- Study on future of Ontario distribution system for the Ontario Government. Study included quantitative and econometric analysis of distribution costs in the Ontario industry.
- Provided Ontario Hydro with regular economic forecasts for use in planning throughout the corporation. Long-term forecasts produced annually; medium-term forecasts produced three times a year. Forecasts included analysis of future of Ontario economy and its relation to electricity demand.
- Led a load forecast team in Ghana of three Canadian economists and up to eight Ghanaian engineers and economists. Produced new load forecast for Ghana, using methodologies new to Ghana including multi variate regressions.
- Study for the World Bank on determination and sharing of benefits of hydroelectric development on international waterways. Published as a World Bank discussion paper. The study reviewed practice on rent sharing in water and hydroelectric development, and developed principles for sharing in certain international developments.
- Taught courses on environmental economics for electricity utility staff and government officials in Nepal and Zimbabwe.