

# Additional Report of Mitchell Rothman

Part of Evidence of Énergie Brookfield Marketing  
Inc.

in Régie de l'énergie

R-3648-2007, Phase 1

Prepared for

Énergie Brookfield Marketing Inc.

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## 1. INTRODUCTION

### 1.1 Mitchell Rothman and Navigant Consulting

My name is Mitchell Rothman. My background is summarized in the report filed with the Régie de l'énergie and now assigned to Phase 2 of this proceeding.<sup>1</sup> My full curriculum vita is attached to that report as Appendix A. A copy of that Report is being filed as part of this Phase of the proceeding.

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.

For the first Report, Énergie Brookfield Marketing Inc. (EBMI) 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.

Subsequent to the preparation and filing of the Report, HQD filed several documents constituting an amendment to its original request.<sup>2</sup> With respect to this amended request, EBMI engaged me, and Navigant Consulting, to

1. Evaluate the proposals contained in the amended request to determine whether they are of benefit to electricity ratepayers in Québec;
2. Compare my results with those of HQD and provide reasons for any discrepancies; and
3. Investigate the implications of deviations from the assumptions made by HQD in their economic analysis.

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<sup>1</sup>R-3648-2007, C-12-8, Report of Mitchell Rothman, (Report).

<sup>2</sup>R-3648-2007, B-33 Demande amendée, HQD-1, Documents 3-5; Document 4 révisé; Document 5 révisé.

## 1.2 Background

Hydro Québec Distribution (HQD) filed its long-term supply plan (the Plan)<sup>3</sup> with the Régie de l'énergie (the Régie), which has assigned it the file number R-3648-2007. Projections in this filing included a forecast of significant surplus of energy in 2008 and 2009.<sup>4</sup> In my Report, I analyzed some implications of these energy surpluses.

Subsequently, HQD filed a number of documents constituting an amendment to the Plan, specifically with reference to the creation and disposition of the energy surpluses.<sup>5</sup> In the Amendment, HQD changed its forecast of demand from that in the Plan. For the 2008-2010 time period, forecast demand for electric energy in the Amendment is lower than that in the Plan. For the 2012-2017 time period, electricity demand in the Amendment is higher than that in the Plan.

These documents include proposed revisions to two supply contracts (the Revised Contracts) between HQD and Hydro Quebec Production (HQP) and a summary of these revisions. The analytical base is contained in the overall request to the Régie to approve these contract modifications.<sup>6</sup>

Essentially, these contract modifications would allow HQD to defer delivery of some electricity under two supply contracts with HQP. The two contracts are for 350 MW baseload and 250 MW cyclable electricity. They expire in 2020. Energy that was deferred can be delivered in subsequent contract years at the contract price for electricity delivered in those subsequent years. The Revised Contracts also specify that HQD cannot sell for profit any of the deferred electricity delivered under the contracts. At the end of the contract term (December 31, 2020) HQP will have the option to repurchase any deferred electricity then remaining, with the purchase price as described in Clause 2.2.8 of the Revised Contract, which will be essentially the price as of Dec. 31, 2020<sup>7</sup>.

The Amendment also refers to the possibility that HQD could renew for a year (2009) its agreement to suspend for the year all deliveries from the Bécancour cogeneration plant owned by TransCanada Energy. The analysis in the Amendment assumes that this suspension is in place.

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<sup>3</sup> R-3648-2007, HQD-1, Document 1. (the Plan)

<sup>4</sup> R-3648-2007, HQD -1, Document 1, pg. 36, Table 5.1.

<sup>5</sup> R-3648-2007, HQD-1, Documents 3 -5, Document 4 révisé, Document 5 révisé

<sup>6</sup> R-3648-2007, HQD -1, Document 5, Demande d'approbation des conventions relatives aux modifications apportées aux contrats d'approvisionnement en électricité en Base et cyclable – entre Hydro-Québec Distribution et Hydro-Québec Production. (The Amendment)

<sup>7</sup> R-3648-2007, HQD-1, Document 3, pg. 6; HQD-1, Document 4, pg. 6.

These Revised Contracts, combined with the further suspension of deliveries from the Bécancour plant, eliminate the surpluses forecast in the Plan.

## 2. OVERVIEW OF METHODOLOGY AND APPROACH

### 2.1 Comparative Economic Analysis

In the Amendment, HQD presented an economic analysis which indicated that the net impact of the Amendment, as HQD proposes to implement it, would provide a benefit to Québec ratepayers of about \$177 million.<sup>8</sup> The analysis compared the total cost over the 10-year period from 2008 to 2017 and found that the total costs to the ratepayer were lower if the deliveries could be deferred to the future.

The analysis in this Additional Report focuses on the same question: Are the total costs to consumers lower if deliveries from these two Revised Contracts are deferred (the Deferral Case), or are the total costs lower if the electricity is delivered according to the original contracts, with surpluses sold as they appear and purchases made as needed to fill subsequent gaps (the Resale Case)? Of interest is the relative total costs under the two cases. The analysis considers the cost to the ratepayers of meeting HQD's obligations under the supply contracts with HQD.

The analysis as carried out by HQD addresses the cost under the Deferral Case as being the cost of purchasing the power that it is obligated for under the contract in the years 2008-2011. In the Deferral Case, it will purchase some of that power in 2008-2011, as needed, and purchase the rest in the deferral period, 2012-2017. Therefore, the analysis requires the cost of buying power under the contracts during the period of deferral and the cost of buying the deferred power in the subsequent years.

Under the Resale Case, both HQD's analysis and Navigant Consulting's analysis assume that all of the contracted power would be purchased in 2008-2011 as contracted. Any amounts of that power identified as surplus in the Amendment would be sold into other markets in those years. This would provide additional revenue to HQD. In the deferral years, 2012-2017, HQD predicts that it will need more power than its existing contracts (with HQD, TCE and wind generators) will provide. It will therefore have to purchase additional power, and the cost of that power is part of the cost in the Deferral Case.

#### 2.1.1 Deferral Case

The Amendment provides the information necessary to compute the cost of buying power during the deferral period. It shows the annual average price under each of the two contracts and how much power HQD expects to purchase under each contract. It also shows the amount

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<sup>8</sup> R-3648-2007, Phase 1, HQD-1, Document 5 Révisé, pg. 14.

deferred in each of the years. The cost of power in 2008-2011 is therefore simply the amount of power taken under each contract times the price under the contract.

In the deferral years, the annual cost will be the price specified in the contract for purchases in those years, times the amount of deferred power purchased in that year.

### **2.1.2 Resale Case**

The Resale Case has costs and offsetting revenues in the first period (2008-2011) and only costs in the deferral period (2012-2017.)

The costs are the costs of purchasing the entire contracted amount in those years. HQD does not expect to be able to absorb within its own system all of the power for which it has contracted in those years, so it will have a surplus. In the Resale Case, HQD must dispose of this surplus by selling it to other markets.

I have already estimated, in my Report, the revenues which would be available to HQD from the sale of such surplus power to New York or New England during this time period. That analysis considered the impacts on the selling value of the transmission losses in Québec, of brokerage and other fees HQD would incur in selling to buyers in New York or New England, and the impact of transmission congestion on the selling price.

For the present analysis, I use a similar methodology. In the Report, I used a forecast of gas prices to estimate future electricity prices in New York in order to estimate the revenues available to HQD from the sale of its surplus electricity. I use a price forecast from the same source to estimate the revenues available to HQD from the sale of the revised amounts of surplus power shown in the Amendment. I extend that price estimate methodology to include the 2012-2017 period for HQD's cost of purchasing electricity from New York. As did HQD, I limit my analysis of the Resale Case to sales to New York. Unlike HQD, I have assumed that any future deficits would be filled by purchases from the New York market.

The major difference between the current methodology and that of my Report is that the current analysis is on an annual basis, while the methodology for my Report used monthly data. I am unable to perform the analysis of the Resale Case on a monthly basis, due to the fact that we were not able to obtain from HQD data on expected monthly surpluses and expected monthly deficits for the two periods under study. However, I have continued with monthly analysis to forecast market prices in New York, then averaged the monthly prices to obtain an annual price.

## **2.2 Identifying and Valuing Sales and Purchases**

In my previous Report, I analyzed information from HQD to obtain a monthly pattern of surplus energy. I then valued its sale on the basis of a monthly forecast of prices in New York and New England. To continue with a monthly analysis, we would require a means of

estimating the monthly pattern for the expected deferred deliveries, for the expected purchases in the future period, and for the expected surpluses which would be sold in the Resale Case. We have not been able to obtain such information. We have therefore performed this analysis on an annual basis, as HQD also did in the Amendment.

For the Resale Case, we still require estimates of sale prices in NYISO in the surplus period and purchase prices in NYISO for the later period. In my previous Report, I 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. Because the electricity futures market is relatively thin, I based my final estimate of NYISO prices on the NYMEX gas futures and future heat rate. As the present analysis requires a forecast of prices considerably farther into the future, I have used only the methodology drawing on the NYMEX futures. The prices we are using are an average of the prices over the most recent calendar month, and will therefore be slightly different from those in my previous Report.

The basis for the prices for both sales and purchases to New York is the price at the NYISO interconnection with Québec. However, there are transmission charges and other costs and fees which the seller to New York or the buyer from New York must pay. These must be taken into account in the economic analysis.

In the previous Report, I enumerated these costs with respect to a sale into New York. I included the costs of losses in Québec, brokerage fees for access to the New York market, and congestion on the interties when I estimated the price that HQD could receive for sales to New York. I have used the same methodology and the same estimates for this analysis.

Purchases from New York also require various payments in addition to the price paid for the energy. These include transmission charges, ancillary services charges, and fees to the system operator. I have added these payments to the cost of electricity purchases from New York.

### **2.3 Comparing Costs**

The essence of the Revised Contracts is to allow rescheduling of the delivery of power. That therefore would move expenditures from one period to another. A proper evaluation of whether such a time shift is economic requires considering the time value of money; that is, the fact that revenues received earlier are more valuable than those received later. To compare the two alternatives, therefore, we use a net present value (NPV) analysis.

### 3. DEMAND AND SURPLUS POWER

#### 3.1 Revised Estimates of Demand and Surplus

HQD's estimates of demand were revised in the Amendment<sup>9</sup> from those contained in the Supply Plan.<sup>10</sup> These changes in demand are shown in Table 3.1 below.

**Table 3.1: Demand Forecast Adjustments in Amendment**

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Demand in Plan	183.8	186.7	190.2	191.5	193.8	194.9	196.3	197.7	199.8	200.8
Forecast Adjustments	(1.4)	(2.5)	(3.4)	(3.7)	(4.0)	(4.3)	(4.5)	(4.6)	(4.6)	(4.5)
Additions for Industry	0.2	0.7	0.8	0.9	3.4	6.0	6.4	7.0	7.3	7.3
Net Additions (Reductions)	(1.2)	(1.8)	(2.6)	(2.7)	(0.5)	1.7	2.0	2.4	2.7	2.8
Adjusted Demand Forecast	182.6	184.9	187.6	188.8	193.3	196.6	198.3	200.1	202.5	203.6

In essence, HQD's revisions reduced the forecast level of demand for the deferral period of 2008-2011 and raised it for the recovery period of 2012-2017. This forecast revision therefore increases the amount of surplus energy in its early years and increases the energy supply that will be needed in the later years. Table 3.2 shows the impact of these revisions.<sup>11</sup>

In my Report, I commented that HQD's load forecast seemed to assume that recent industrial load losses in Québec will not be sustained, and that I saw a significant risk of continued deterioration in the pulp and paper sector. This revised demand forecast, while at lower levels throughout the deferral period, still predicts a rebound in energy demand in 2009 and 2010, though it is lower than the growth forecast in the Plan. There remains a significant risk that industrial demand will deteriorate further during that time period.

**Table 3.2: HQD Expected Purchases and Sales by Year**

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
<i>FORECAST IN PLAN</i>										
Energy Purchases Required	5.0	7.8	11.3	12.6	15.0	16.0	17.4	18.9	21.0	22.0
Energy Contracted	10.5	10.7	11.7	12.7	14.7	16.5	17.7	18.9	20.0	20.0
Additional Required (Surplus)	(5.6)	(2.9)	(0.3)	(0.1)	0.2	(0.5)	(0.3)	0.0	0.9	2.0
<i>REVISED FORECAST</i>										
Additional Requirements	3.8	6.1	8.7	9.9	14.4	17.7	19.4	21.3	23.6	24.8
Energy Contracted	6.5	6.7	11.7	12.7	14.7	16.5	17.7	18.9	20.0	20.0
Required Supply (Surplus)	(2.7)	(0.6)	(2.9)	(2.8)	(0.4)	1.2	1.7	2.4	3.6	4.8

<sup>9</sup> R-3648-2007, HQD-1, Document 5, pg. 9, Table 1

<sup>10</sup> R-3648-2007, HQD-1, Document 1, pg. 36, Table 5.1

<sup>11</sup> The Revised Forecast data in Table 3.2 also reflect the closure of the TCE plant for both 2008 and 2009. The Forecast in Plan data do not reflect the closure of the TCE plant for 2008.

### 3.2 Scheduling of Deferrals, Returns, Purchases and Sales

The amounts shown in Table 3.2 above are totals for the years involved. In the Amendment, HQD indicated that it would not defer deliveries for the months of January and February, in order to have the benefit of the contracted capacity during its peak demand period. Because this analysis is on an annual basis, I am not able to take this scheduling into account.

### 3.3 Demand Balance

Table 3.3 shows the demand balance as presented in the Amendment. This demand balance forms the basis for the analyses in this Report.

**Table 3.3: Demand Balance (TWh)**

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Plan Requirements	183.8	186.7	190.2	191.5	193.8	194.9	196.3	197.7	199.8	200.8
+ Withdrawal from reserve for new industrial projects	0.0	0.0	(1.1)	(1.4)	(1.8)	(2.1)	(2.2)	(2.3)	(2.4)	(2.3)
+ Impact of the February 2008 overview	(1.4)	(2.5)	(2.2)	(2.2)	(2.2)	(2.2)	(2.2)	(2.2)	(2.2)	(2.2)
Adjustments to Plan Requirements Sub-Total:	(1.4)	(2.5)	(3.4)	(3.7)	(4.0)	(4.3)	(4.5)	(4.6)	(4.6)	(4.5)
+ New Alcoa Requirements										
+ Increase between 66 to 200 MW	0.2	0.5	0.6	0.7	0.8	0.9	1.0	1.1	1.2	1.2
+ Baie-Comeau modernisation project (175 MW)	0.0	0.2	0.2	0.2	0.4	0.6	0.9	1.3	1.6	1.6
+ Additional Industrial Development (500 MW)	0.0	0.0	0.0	0.0	2.3	4.5	4.5	4.5	4.5	4.5
New Additions for Industry:	0.2	0.7	0.8	0.9	3.5	6.0	6.4	6.9	7.3	7.3
Adjusted Plan Requirements	182.6	184.9	187.6	188.7	193.3	196.6	198.2	200.0	202.5	203.6
Patrimonial Electricity Volume	178.9	178.9	178.9	178.9	178.9	178.9	178.9	178.9	178.9	178.9
Additional Supply Requirements	3.8	6.1	8.7	9.9	14.4	17.7	19.4	21.3	23.6	24.8
Non-Proprietary Supply	6.5	6.7	11.7	12.7	14.7	16.5	17.7	18.9	20.0	20.0
Required Supply (Surplus)	(2.7)	(0.6)	(2.9)	(2.8)	(0.4)	1.2	1.7	2.0	3.6	4.8

## 4. SALE AND PURCHASE PRICES

### 4.1 Deferral Case

We do not need estimates of the value of the power in other jurisdictions for the Deferral Case. The prices HQD will pay on delivery for the deferred power are set in the contracts with HQP and are shown clearly in Table 2 of the Amendment. There are different prices for the 350 MW baseload and 250 MW cycling contract. Our analysis uses these prices as they are computed from the Contracts.<sup>12</sup>

The relevant prices for purchases from HQD under the Contracts are repeated in Table 5.1 for the economic analysis.

### 4.2 Resale Case

For the Resale Case, the sale and purchase prices are not set in advance. This estimate assumes that HQD would take delivery and resell the power. As noted in my Report, there are effectively no markets in Québec for this surplus power, so it would have to be sold into other jurisdictions. In my Report, I analyzed the possible prices in both New York and New England. In this Additional Report, I have focused only on the New York market as a base case.

In the deferral period, HQD would be selling power into the New York market. In the recovery period, HQD would be buying power from the New York market.<sup>13</sup>

In my previous Report, we considered two methodologies to estimate future electricity prices in NYISO and ISO-NE. In this Report, we use only the method based on the NYMEX futures prices for gas. The methodology is explained in full in the Report.<sup>14</sup> The future electricity price analysis was performed on a monthly basis; the annual prices used for the computations is an average of the monthly prices.

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<sup>12</sup>R-3515-2003, HQD-1 Document 1 and Document 2 (the Contracts).The prices shown include capacity and energy charges..

<sup>13</sup> As was pointed out in a response to an Information Request from the Régie, this assumption may understate the sales revenues and overstate the purchase costs. With the new line to Ontario in place, HQD could sell to Ontario when its price is above that in New York and buy from Ontario when its price is below that in New York. We do not undertake a formal analysis of the value of these options because we do not have a reliable source of forecasts of electricity prices in Ontario.

<sup>14</sup> R-3648-2007, C-12-8, pp 17-18.

#### 4.2.1 Estimated Future Electricity Market Prices for HQD Sales

The methodology is based on historical average market heat rates, which are the ratio between electricity prices and gas prices. NYISO 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.<sup>15</sup> The market heat rates used in the computations are averages of historical heat rates.<sup>16</sup> I used the same market heat rate for every year.

My Report showed a monthly analysis of the relationship between historical gas and electricity prices and market heat rates. The gas prices used were based on the Texas Eastern M-3 hub, which is located in Pennsylvania and serves New England and New York. The complete analysis up to 2011 is in my Report.<sup>17</sup> For this analysis, I used the methodology from my first Report for the years up to 2011. I extended that methodology to 2012. However, NYMEX does not trade a gas futures contract based at the Texas Eastern M-3 hub for years beyond 2012. For years beyond 2012, therefore, I used the NYMEX futures price for gas at the Henry Hub and combined it with a forecast of the basis differential between Henry Hub and the Texas Eastern M-3 hub to arrive at a gas price forecast for this analysis.

Table 4.1 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 a recent month (20 trading days) 2008. The gas prices for the years up to 2011 (and consequently electricity prices) differ somewhat from those provided in my Report<sup>18</sup> because we have updated these gas prices by using the most recent monthly data.

**Table 4.1: Projected Gas Prices, Heat Rates and Average Electricity Prices**

	Annual Gas/NYISO Electricity Prices									
	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Texas Eastern Zone M-3 (\$/mmBtu)	\$10.95	\$11.03	\$10.28	\$9.95	\$9.88	\$9.85	\$9.95	\$10.09	\$10.28	\$10.49
Market Heat Rate (Btu/kWh)	7,450	7,451	7,451	7,451	7,450	7,451	7,451	7,451	7,450	7,451
NYISO-HQ Interface (\$/MWh)	\$83.50	\$81.81	\$76.30	\$73.93	\$73.40	\$73.24	\$73.93	\$74.99	\$76.38	\$77.95

<sup>15</sup> R-3648-2007, C-12-8, pg 17.

<sup>16</sup> For the analysis of market heat rates, see Table 4.4 of the Report, , R-3648-2007, C-12-8, pg. 18

<sup>17</sup> R-3648-2007, C-12-8, pp 17-18

<sup>18</sup> R-3648-2007, C-12-8, pg 18.

The bottom line in Table 4.1 is our projection of the New York market price at the NYISO/HQ interface. As noted in my Report, the price that HQD can expect to receive is less than this, because of three factors which are explained more fully in my Report<sup>19</sup>

- Transmission losses on HQT’s system, at a rate of 5.2%;
- Brokerage fees and reservation fees on NYISO’s system. These are estimated to amount to \$0.91/MWh in 2008. For this analysis, we assume that they increase at the same rate as is used for other escalation, or 2%.
- Transmission congestion. Table 4.6 in my Report<sup>20</sup> indicated an annual average price reduction of \$1.52 due to congestion on the interconnection between New York and Québec. I use this as a base value and escalate it by 2% per year. As noted in my Report<sup>21</sup>, this is a conservative estimate of the reduction in price due to congestion; that is, it likely overestimates the price reduction. In response to an information request from the Régie, I performed an analysis which indicated that the size of the price reduction is not very sensitive to the level of congestion.<sup>22</sup>

The prices that HQD could expect to receive for baseload sales, after making these adjustments, are shown in Table 4.2. 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 market, market heat rates within NYISO, and electricity price basis differences between the main NYISO and ISO-NE markets and its interface 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 in my Report<sup>23</sup>, or to concentrate sales in days or seasons when prices are higher, the price it receives could increase.

**Table 4.2: Sale and Purchase Prices for Electricity in New York**

	Projected Sales/Purchase Prices (\$/MWh)									
	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
HQD Sale Proceeds	\$78.22	\$76.68	\$71.59	\$69.42	-	-	-	-	-	-
HQD Purchase Prices	-	-	-	-	-	\$78.76	\$79.56	\$80.74	\$82.24	\$83.92

These sale prices are used for the computation of the revenues that HQD could expect to receive from sales of the surplus energy in the NYISO market.

<sup>19</sup> R-3648-2007, C-12-8, pg 19.

<sup>20</sup> Ibid.

<sup>21</sup> Ibid..

<sup>22</sup> R-3648-2007, C-12-12, pp 9-10

<sup>23</sup> R-3648-2007, C-12-8, pg 19

#### 4.2.2 Estimated Future Electricity Prices for HQD Purchases

Table 4.1 showed the estimate of NYISO market prices, which will be the cost of the bulk electricity. When HQD is buying from the New York market, it will pay a number of tariffs and fees in addition to the cost of the electricity.

Table 4.3 lists these costs and fees and their amounts in the first months of 2008. The costs include the transmission tariff, NYPA Transmission Adjustment Charge (NTAC), payments for requisite ancillary services like operating reserve, and payments to the system operator to support its operations. Some of these costs vary monthly; the values here are for the start of 2008. Together, the costs total about \$5 per MWh. We have used that value as an estimate of average current costs. For future years, this cost was escalated at a rate of 2% per year. The purchase prices shown in Table 4.2 reflect these costs and fees.

**Table 4.3: New York ISO Uplifts and Costs**

Charge	Amount (\$/MWh)
Combined Schedule 1 Rate for Withdrawals	\$0.63
OATT Rate Schedule 2 Charge	\$0.34
Transmission Service Charge (TSC) Rate	\$2.19
NYPA Transmission Adjustment Charge (NTAC)	\$0.50
Uplift and Operating Reserve (OR) Charge	\$0.74
Total	\$4.40

## 5. ECONOMIC ANALYSIS

### 5.1 Base Economic Analysis

The results of our economic analysis of the base case are shown below in Table 5.1. Our analysis shows the Resale Case to be preferred over the Deferral Case. The difference in net present value is about \$47 million.

**Table 5.1: Economic Analysis of Base Case**

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
<b>Prices in \$/MWh</b>										
HQP Price - 350 MW	\$50.07	\$51.07	\$52.09	\$53.13	\$54.19	\$55.28	\$56.38	\$57.51	\$58.66	\$59.83
HQP Price - 250 MW	\$53.86	\$54.94	\$56.04	\$57.16	\$58.30	\$59.47	\$60.65	\$61.87	\$63.11	\$64.37
NYISO Sale Price	\$78.22	\$76.68	\$71.59	\$69.42						
NYISO Purchase Price						\$78.76	\$79.56	\$80.74	\$82.24	\$83.92
<b>Deferral Case</b>										
<u>Volumes in TWh</u>										
HQD Deficit (Surplus)	(2.7)	(0.6)	(2.9)	(2.8)	(0.4)	1.2	1.7	2.4	3.6	4.8
Deferrals - 350-MW Contract	2.7	0.6	2.9	2.8						
Deferrals - 250-MW Contract										
Purchases - 350-MW Contract	0.3	2.5	0.1	0.3						
Purchases - 250-MW Contract	2.2	2.2	2.2	2.2						
Returns - 350-MW Contract						1.2	1.7	2.4	3.6	0.2
Returns - 250-MW Contract										
Cumulative Deferrals - 350-MW Contract	2.7	3.3	6.2	9.0	9.0	7.9	6.2	3.8	0.2	
Cumulative Deferrals - 250-MW Contract										
<u>Costs (Revenues) in \$ million</u>										
Purchases from HQP	\$134	\$247	\$130	\$140	\$0	\$65	\$95	\$138	\$211	\$11
Transactions with NYISO										
<b>TOTAL COST</b>	<b>\$134</b>	<b>\$247</b>	<b>\$130</b>	<b>\$140</b>	<b>\$0</b>	<b>\$65</b>	<b>\$95</b>	<b>\$138</b>	<b>\$211</b>	<b>\$11</b>
<b>Contract Case</b>										
<u>Volumes in TWh</u>										
Purchases - 350-MW Contract	3.1	3.1	3.1	3.1						
Purchases - 250-MW Contract	2.2	2.2	2.2	2.2						
Sales to NYISO	2.7	0.6	2.9	2.8						
Purchases from NYISO						1.2	1.7	2.4	3.6	0.2
<u>Costs (Revenues) in \$ million</u>										
Purchases from HQP	\$271	\$277	\$282	\$288	\$0	\$0	\$0	\$0	\$0	\$0
Transactions with NYISO	(\$214)	(\$45)	(\$209)	(\$194)	\$0	\$93	\$134	\$194	\$295	\$16
<b>TOTAL COST</b>	<b>\$57</b>	<b>\$232</b>	<b>\$73</b>	<b>\$94</b>	<b>\$0</b>	<b>\$93</b>	<b>\$134</b>	<b>\$194</b>	<b>\$295</b>	<b>\$16</b>
Net Cost of Deferral in \$ million	\$77	\$15	\$57	\$46	\$0	(\$28)	(\$39)	(\$56)	(\$85)	(\$4)
<b>Net Present Value in \$ million</b>	<b>\$47</b>									

The top lines of this table show the prices used for the analysis. The 2008 prices paid to HQP for the 350 MW and 250 MW contracts were computed from the original contracts as filed by HQD.<sup>24</sup> They include charges under the contract for both capacity and energy. These prices were then escalated at 2% per year. The middle section of the table analyzes the Deferral Case and the lower section shows the Resale Case.

<sup>24</sup> R-3515-2003, HQD-1 Document 1 and Document 2. HQD referred to these contracts in response to EBMI's information request No. 4.7.

The two rows at the bottom of Table 5.1 give the net cost for the Deferral Case. The value for each year is the cost of the Deferral Case minus the cost of the Resale Case. The Deferral Case is more costly in the years in which the deferrals occur, because the cost is not offset by profits from sales of the surplus power. The Deferral Case is less costly in the years when the power is being returned, because the power is being purchased under a contract that has lower prices than the market.

To compute a net benefit in 2008, we used a net present value analysis with a discount rate of 8.1%. This is the approved rate of return for HQD.<sup>25</sup> The net benefit of the Resale Case is \$47 million in NPV in 2008.

This advantage for the Resale Case comes from the fact that it reduces the expenditures on the contracted electricity in the early years while spending more in later years. Given the time value of money, as represented by the discounted NPV, this timing of costs and benefits helps the Resale Case. By contrast, the Deferral Case has higher costs in the early years in order to reduce costs in later years.

## 5.2 Comparison to the HQD Economic Analysis

This result is markedly different from the analysis presented by HQD in its Amendment. Its Economic Analysis table shows an advantage for the Deferral Case of about \$177 million in NPV.<sup>26</sup>

This difference is not due to the economic analysis of the Deferral Case. Our annual costs in that case are essentially identical to those shown in the Amendment.<sup>27</sup>

There are several sources of difference in our analysis of the Resale Case:

- Purchasing from New York power needed in the later period, rather than buying additional wind power;
- Lower adjustment to selling price in New York;
- Higher New York market price when selling to New York; and
- Higher discount rate.

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<sup>25</sup> D-2008-024, pg 4.

<sup>26</sup> R3648-2007, HQD-1, Document 5 révisé, pg. 14.

<sup>27</sup> R3648-2007, HQD-1, Document 5

Perhaps the most important is our use of a purchase from the New York market as the alternative to the return of deferred power. We consider a purchase from New York as representative of the likely cost of buying electricity on a market in 2012-2017. HQD used as its alternative the cost of additional generation from wind, which we do not consider representative of the cost in a power market. The cost of such renewables is greater than the cost of imported power. The use of renewables to fill any gaps in HQD procurement would be the result of a political decision by government. Current policy is to set a target for generation from wind; to make wind the marginal choice would require a political decision. In our analysis, we have assumed that HQD will act in the best economic interests of its ratepayers and purchase power from the most economical sources available.

Our analysis has higher sales revenues from the New York market. One important difference is the adjustments made to the New York border price. HQD applied a \$5 per MWh adjustment to the base price.<sup>28</sup> Our analysis adjusted the base price to account for price reductions due to congestion on the interconnection, but it was only \$1.52, based on the historic pattern of prices during congested and uncongested times.

The HQD analysis based its New York market price on the historical short-term average prices at Zone A for the first two months of 2008. The price was then adjusted by a basis differential to Zone M, which is where the electricity would enter the New York market.<sup>29</sup> We based our New York market price on an analysis of future gas prices. Table 5.2 compares the New York selling price from the Navigant Consulting analysis with those used by HQD in its analysis.<sup>30</sup>

An interesting observation from the data in Table 5.2 is that HQD's apparent underestimate of the sales price available to it in the New York market could affect its economic analysis of the suspension of the contract with TCE for deliveries from the Bécancour plant. As I noted in my Report, the sale of surplus power in New York can produce substantial revenues; an underestimate of those revenues underestimates the value of continuing to receive power from Bécancour and selling it to markets in the United States.

**Table 5.2: Comparison of Sale Price Estimates (\$/MWh)**

	2008	2009	2010	2011
Navigant Consulting Estimate of HQD Sale Proceeds	\$78.22	\$76.68	\$71.59	\$69.42
HQD Estimate of HQD Sale Proceeds	\$57.27	\$59.97	\$59.15	\$58.65

<sup>28</sup> R3648-2007, HQD-1, Document 5, pg. 13.

<sup>29</sup> R-3648-2007, HQD-3, Document 1, p. 46.

<sup>30</sup> R-3648-2007, HQD-1, Document 5 révisé, pg. 21.

Finally, we have used a higher discount rate than HQD. We inferred a discount rate of 6.38% from the information in their table. We have used a discount rate of 8.1%, which is HQD's approved rate of return<sup>31</sup> and therefore an appropriate way to express the time value of money to HQD.

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<sup>31</sup> D-2004-024, pg. 4.

## 6. ALTERNATIVE SCENARIO

I pointed out in Section 3 of this report that the Amendment's changes to HQD's demand forecast reduced expected load in the near future and increased it later. Much of this later increase (4.5 TWh per year) comes from the assumption that 500 MW of load will be added to the system during the year 2012, and will stay in place for the remainder of the period.

As an alternative scenario to test how crucial this assumption is, we have analyzed a scenario in which that additional 500 MW of demand does not appear. Table 6.1 below shows the result of this alternative assumption. Supply continues to be in surplus in every year until 2016.

**Table 6.1: Alternative Energy Balance (2008-2017)**

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Plan Requirements	183.8	186.7	190.2	191.5	193.8	194.9	196.3	197.7	199.8	200.8
+ Withdrawal from reserve for new industrial projects	0.0	0.0	(1.1)	(1.4)	(1.8)	(2.1)	(2.2)	(2.3)	(2.4)	(2.3)
+ Impact of the February 2008 overview	(1.4)	(2.5)	(2.2)	(2.2)	(2.2)	(2.2)	(2.2)	(2.2)	(2.2)	(2.2)
Adjustments to Plan Requirements Sub-Total:	(1.4)	(2.5)	(3.4)	(3.7)	(4.0)	(4.3)	(4.5)	(4.6)	(4.6)	(4.5)
+ New Alcoa Requirements										
+ Increase between 66 to 200 MW	0.2	0.5	0.6	0.7	0.8	0.9	1.0	1.1	1.2	1.2
+ Baie-Comeau modernisation project (175 MW)	0.0	0.2	0.2	0.2	0.4	0.6	0.9	1.3	1.6	1.6
+ Additional Industrial Development (500 MW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
New Additions for Industry:	0.2	0.7	0.8	0.9	1.2	1.5	1.9	2.4	2.8	2.8
Adjusted Plan Requirements	182.6	184.9	187.6	188.7	191.0	192.1	193.7	195.5	198.0	199.1
Patrimonial Electricity Volume	178.9	178.9	178.9	178.9	178.9	178.9	178.9	178.9	178.9	178.9
Additional Supply Requirements	3.7	6.0	8.7	9.8	12.1	13.2	14.8	16.6	19.1	20.2
Non-Proprietary Supply	6.5	6.7	11.7	12.7	14.7	16.5	17.7	18.9	20.0	20.0
Required Supply (Surplus)	(2.8)	(0.7)	(3.0)	(2.9)	(2.6)	(3.3)	(2.9)	(2.3)	(0.9)	0.2

As in the base case, we have analyzed two approaches to this ongoing surplus. The first is to defer delivery for all surplus amounts, allowing undelivered surplus to accumulate in the expectation that demand will increase in the future. This is the approach taken in the Deferral Case. The second, as in the Resale Case, is to take delivery of all of the contracted power under the contract and sell into the New York market all surpluses as they become available and to buy from the New York market electricity to meet any subsequent needs.

We used the same methodology and assumptions in this case as in the analysis of the Deferral Case, but we extended the analysis to 2020. Since the Plan does not have a demand forecast beyond 2017, we extended the forecast by projecting to then a trend from the last forecast years. In 2016 and 2017, the HQD deficit increases by 1.2 TWh per year, according to the forecast in the Plan. We extended the analysis to 2020 by assuming that the deficit would continue to increase by 1.2 TWh per year during the remaining three years of the contract.

In the Deferral Case for this scenario, the end-state provisions of the amended contract become important because a significant amount of undelivered deferred energy has accumulated when the contract expires at the end of 2020. At the end of the contract term (December 31, 2020)

HQP will have the option to repurchase any deferred electricity then remaining, with the purchase price as described in Clause 2.2.8 of the Revised Contracts, which will be essentially the price as of Dec. 31, 2020<sup>32</sup>.

The result of this economic analysis is presented in Table 6.2. It shows a net benefit of the Resale Case of \$258 million in NPV in 2008. This reflects the fact that, under this scenario, there are no positive annual returns to the Deferral Case until 2016. There is also a significant amount of power left undelivered, valued at a price that is well below the projected market price.

**Table 6.2: Economic Analysis of Alternative Case**

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
<b>Prices in \$/MWh</b>													
HQP Price - 350 MW	\$50.07	\$51.07	\$52.09	\$53.13	\$54.19	\$55.28	\$56.38	\$57.51	\$58.66	\$59.83	\$61.03	\$62.25	\$63.50
HQP Price - 250 MW	\$53.86	\$54.94	\$56.04	\$57.16	\$58.30	\$59.47	\$60.65	\$61.87	\$63.11	\$64.37	\$65.65	\$66.97	\$68.31
NYISO Sale Price	\$78.22	\$76.68	\$71.59	\$69.42	\$68.94	\$68.81	\$69.47	\$70.48	\$71.79				
NYISO Purchase Price										\$83.92	\$85.65	\$87.47	\$89.59
<b>Scenario With Deferrals</b>													
<b>Volumes in TWh</b>													
HQD Surplus (Deficit) - Original	(2.7)	(0.6)	(2.9)	(2.8)	(0.4)	1.2	1.7	2.4	3.6	4.8	6.0	7.2	8.4
Excluding Additional 500 MW					(2.3)	(4.5)	(4.5)	(4.5)	(4.5)	(4.5)	(4.5)	(4.5)	(4.5)
HQD Surplus (Deficit)	(2.7)	(0.6)	(2.9)	(2.8)	(2.7)	(3.3)	(2.8)	(2.1)	(0.9)	0.3	1.5	2.7	3.9
Deferrals - 350-MW Contract	2.7	0.6	2.9	2.8	2.7	3.1	2.8	2.1	0.9				
Deferrals - 250-MW Contract						0.3							
Purchases - 350-MW Contract	0.3	2.5	0.1	0.3	0.4		0.3	1.0	2.2	3.1	3.1	3.1	3.1
Purchases - 250-MW Contract	2.2	2.2	2.2	2.2	2.2	1.9	2.2	2.2	2.2	2.2	2.2	2.2	2.2
Returns - 350-MW Contract										0.3	1.5	2.7	3.5
Returns - 250-MW Contract													0.3
Cumulative Deferrals - 350-MW Contract	2.7	3.3	6.2	9.0	11.7	14.8	17.6	19.7	20.6	20.3	18.8	16.1	12.6
Cumulative Deferrals - 250-MW Contract						0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
<b>Costs (Revenues) in \$ million</b>													
Purchases from HQP	\$134	\$247	\$130	\$140	\$148	\$115	\$147	\$191	\$265	\$342	\$422	\$506	\$567
Disposition of Unused Deferrals Transactions w/ NYISO													(\$31)
<b>TOTAL COST</b>	<b>\$134</b>	<b>\$247</b>	<b>\$130</b>	<b>\$140</b>	<b>\$148</b>	<b>\$115</b>	<b>\$147</b>	<b>\$191</b>	<b>\$265</b>	<b>\$342</b>	<b>\$422</b>	<b>\$506</b>	<b>\$536</b>
<b>Scenario Without Deferrals</b>													
<b>Volumes in TWh</b>													
Purchases - 350-MW Contract	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1
Purchases - 250-MW Contract	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2
Sales to NYISO	2.7	0.6	2.9	2.8	2.7	3.3	2.8	2.1	0.9	0.0	0.0	0.0	0.0
Purchased from NYISO	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3	1.5	2.7	3.8
<b>Costs (Revenues) in \$ million</b>													
Purchases from HQP	\$271	\$277	\$282	\$288	\$294	\$300	\$306	\$312	\$318	\$324	\$331	\$338	\$344
Transactions with NYISO	(\$214)	(\$45)	(\$209)	(\$194)	(\$186)	(\$229)	(\$195)	(\$148)	(\$65)	\$25	\$128	\$236	\$337
<b>TOTAL COST</b>	<b>\$57</b>	<b>\$232</b>	<b>\$73</b>	<b>\$94</b>	<b>\$108</b>	<b>\$71</b>	<b>\$110</b>	<b>\$164</b>	<b>\$253</b>	<b>\$350</b>	<b>\$459</b>	<b>\$574</b>	<b>\$681</b>
Net Cost of Deferral in \$ million	\$77	\$15	\$57	\$46	\$40	\$44	\$37	\$27	\$12	(\$7)	(\$37)	(\$68)	(\$145)
<b>Net Present Value in \$ million</b>	<b>\$258</b>												

This analysis illustrates that there are risks to the application of the Revised Contracts. Because they do not allow HQD to sell the deferred power at a profit when it is delivered, it could force HQD to forego the benefits of the contracted electricity by allowing HQP to purchase it back at the end of the contract term.

Further, my analysis concludes that the use of deferrals is less economic than taking and selling the power, and not without risk to HQD.

<sup>32</sup> R-3648-2007, HQD-1, Document 3, pg. 6; HQD-1, Document 4, pg. 6.

## 7. CONCLUSIONS

In this Additional Report, I have analyzed the economic consequences of the Revised Contracts as HQD has indicated they would implement them. Unlike HQD, I come to the conclusion that this proposed use of these contracts would impose an overall economic cost on Québec ratepayers. This cost comes from the fact that the proposed use of the Revised Contracts would forego profits in the short term in favour of lower costs in the longer term. But given the time value of money and the relative sizes of the foregone short-term profits and the longer-term savings, the overall evaluation has a negative net present value.

Further, my analysis concludes that the use of deferrals under the Revised Contracts is not without risk to HQD. These risks arise in the case where HQD faces continued surpluses and continues to defer delivery under the Revised Contracts.