

RÉGIE DE L'ÉNERGIE

DOSSIER : R-3648-2007

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**RÉPONSES D'ÉNERGIE BROOKFIELD MARKETING INC.  
(« EBMI ») À LA DEMANDE DE RENSEIGNEMENTS N° 1  
DE LA RÉGIE DE L'ÉNERGIE  
PHASE II**

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**Question 1**

1. **Références :** (i) Pièce C-12.8-EBMI, rapport d'expert, page 20;  
 (ii) Pièce B-1-HQD-1, document 1, page 42.

**Préambule :**

La référence (i) présente le tableau suivant relatif aux revenus estimés découlant de la revente des surplus d'électricité :

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	\$198.9
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

À la référence (ii), le Distributeur mentionne que :

« [...] même si la nouvelle interconnexion avec l'Ontario donnera accès à un marché additionnel, le bilan en puissance et les objectifs du Ontario Power Authority laissent toutefois peu de marge de manoeuvre afin qu'une portion de la puissance installée, dans ce marché, puisse contribuer à satisfaire les besoins du Québec. »

**Demandes :**

- 1.1 Veuillez indiquer les revenus estimés de revente en tenant compte de la nouvelle interconnexion avec l'Ontario (référence (ii)).

**R1.1 :** We estimated the resale revenues shown in Table 4.8 of the referenced document, Piece C-12.8-EBMI, rapport d'expert, pg. 20 (the Report), using a forward-looking analysis. The forecast we used was of monthly electricity prices in the potential export markets of New York and New England, based on a forecast of market heat rates and gas prices.<sup>1</sup> For a full analysis of the answer to this question, we would need a comparable forecast of electricity prices in Ontario in order to estimate the resale revenue in that market given the improved access to be granted by the new transmission line.

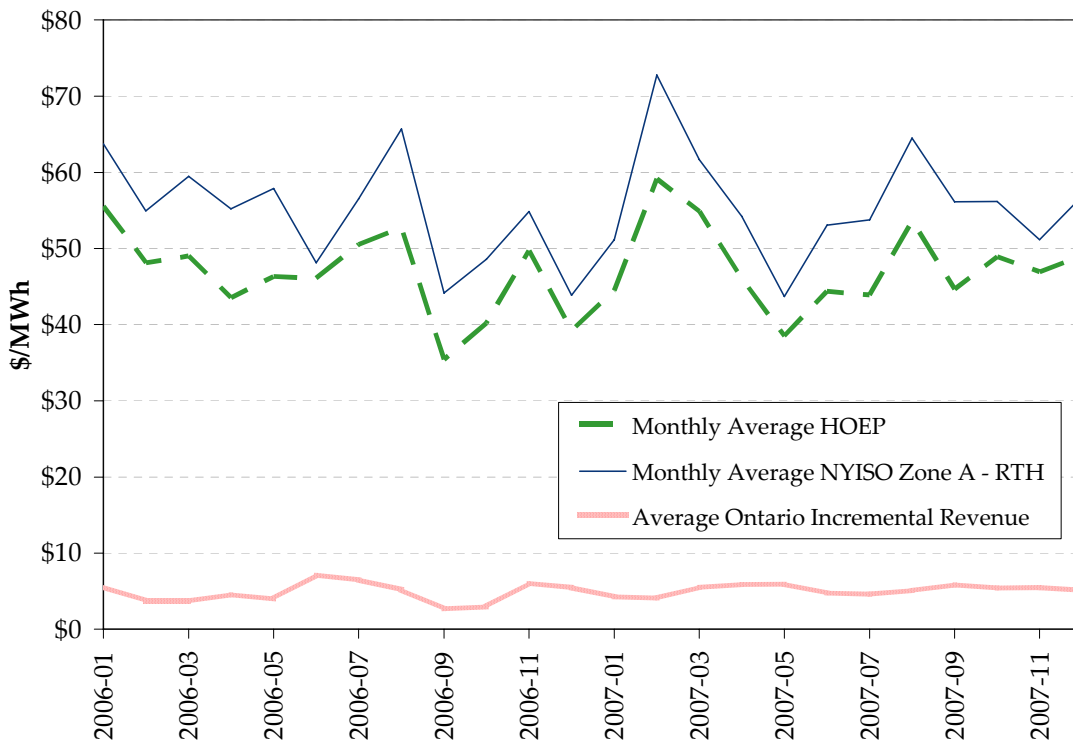
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<sup>1</sup> Piece C-12.8-EBMI, rapport d'expert, pg. 20.

However, we cannot apply the same methodology to forecast electricity prices in Ontario. The Ontario electricity system is not as reliant on gas as are the New York and New England systems, and there is no market for electricity futures in Ontario that is as open and transparent as NYMEX. To answer this question, therefore, we have estimated the impact based on an analysis of the history of the difference between the Ontario market prices (the Hourly Ontario Energy Price, HOEP) and the New York market prices.

We have performed this analysis on the hourly prices in both markets for the calendar years 2006 and 2007. We found that the average monthly prices were higher in New York than Ontario in all of those months. However, even though the average New York price was higher in all months, there were also some hours in each month when the Ontario price was above the New York price. The average monthly prices and monthly incremental revenue are shown in Figure 1.1 below.

**Figure 1.1 Monthly Average Hourly Electricity Prices and Incremental Revenue in New York and Ontario (2006-2007)**

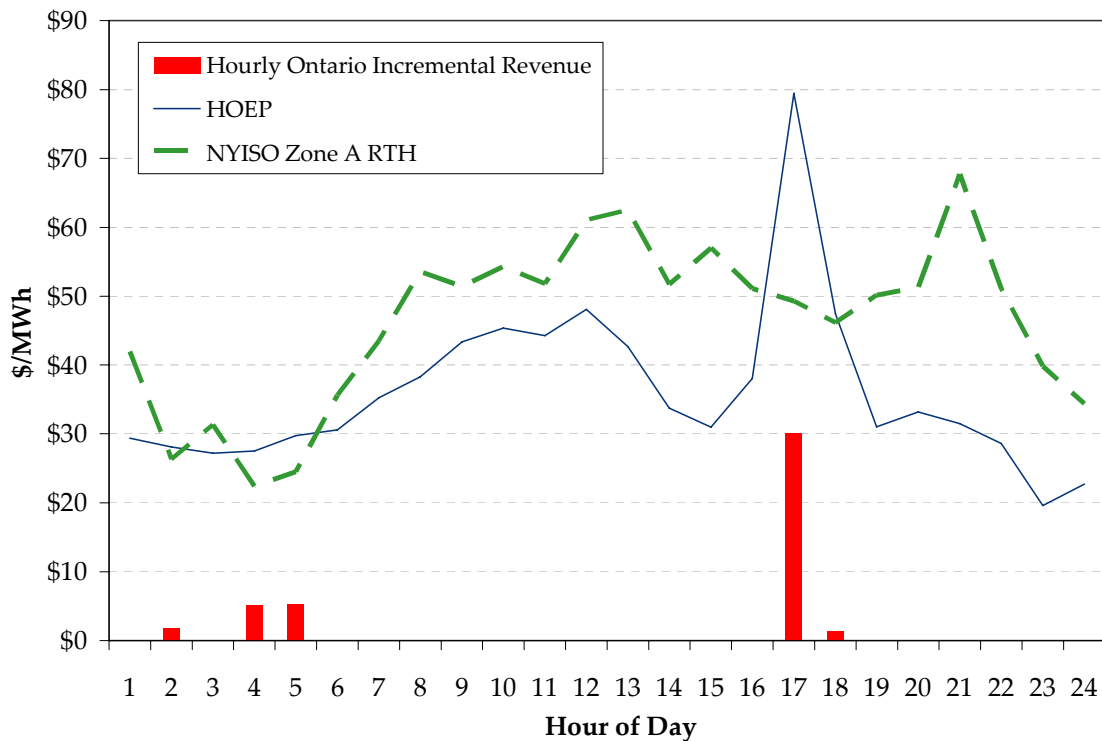


Data source: NYISO, Ontario IESO.

We therefore can treat New York as the primary market for the sales; as a secondary market, we assume that the surplus would be sold to Ontario only in those hours when its price is higher than the New York price. To illustrate the times when the Ontario price is above the New York price, Figure 1.2 shows a representative day. In most hours, the New York price is above the Ontario price, but the reverse is true in five

hours. The difference is small in two of those hours, about \$5 in two hours, and about \$30 in one hour. We are considering these differences to be the incremental revenue available from selling into Ontario rather than New York.

**Figure 1.2: Typical Day Hourly Electricity Price and Incremental Revenue Profile**



Data source: NYISO, Ontario IESO

Finally, we have computed the resulting monthly incremental revenue (in \$/MWh) for the two years 2006-2007. Compared to the electricity prices to be received by HQD as computed in the Report, these are in the range of an additional 5-10%. These prices, of course, refer to the years 2006-2007, while the Report refers to the years 2008-2011.

These prices are the result of an analysis performed specifically to answer this question which is not to be taken as a definitive analysis. As already noted, these prices are historical rather than forward-looking, so they are not directly comparable. The analysis assumes that the electricity could be sold into Ontario so as to realize all of the positive differential between Ontario and New York prices, ignoring any seams or other transactions issues and ignoring transmission congestion. The incremental revenues shown here are not adjusted for the factors listed on pg. 19 of the Report.<sup>2</sup>

<sup>2</sup> Piece C-12.8-EBMI, rapport d'expert, pg. 19

**Table 1.1 : Monthly Average Hourly Prices and Monthly Incremental Revenue (2006-2007)**

Year-Month	Average of HOEP (\$/MWh)	Average of RTH Price (\$/MWh)	Average Incremental Ontario Revenue (\$/MWh)
2006-01	\$55.54	\$63.76	\$5.52
2006-02	\$48.12	\$54.92	\$3.73
2006-03	\$49.01	\$59.48	\$3.73
2006-04	\$43.52	\$55.18	\$4.57
2006-05	\$46.32	\$57.87	\$3.97
2006-06	\$46.08	\$48.11	\$7.12
2006-07	\$50.52	\$56.50	\$6.48
2006-08	\$52.72	\$65.66	\$5.18
2006-09	\$35.42	\$44.13	\$2.67
2006-10	\$40.20	\$48.57	\$2.94
2006-11	\$49.71	\$54.82	\$6.06
2006-12	\$39.25	\$43.85	\$5.48
2007-01	\$44.48	\$51.12	\$4.24
2007-02	\$59.12	\$72.78	\$4.08
2007-03	\$54.85	\$61.68	\$5.50
2007-04	\$46.05	\$54.19	\$5.88
2007-05	\$38.50	\$43.69	\$5.93
2007-06	\$44.38	\$53.04	\$4.75
2007-07	\$43.90	\$53.79	\$4.62
2007-08	\$53.62	\$64.50	\$5.07
2007-09	\$44.63	\$56.13	\$5.84
2007-10	\$48.91	\$56.16	\$5.41
2007-11	\$46.95	\$51.13	\$5.48
2007-12	\$49.08	\$56.90	\$5.11
<b>Average</b>	<b>\$47.12</b>	<b>\$55.33</b>	<b>\$4.97</b>

Data source: NYISO, Ontario IESO

1.2 Veuillez indiquer si le marché de l'électricité de l'Ontario pourrait être complémentaire au marché du Québec (lequel présente une demande élevée en hiver), une fois la nouvelle interconnexion avec l'Ontario mise en service. Veuillez expliquer votre réponse.

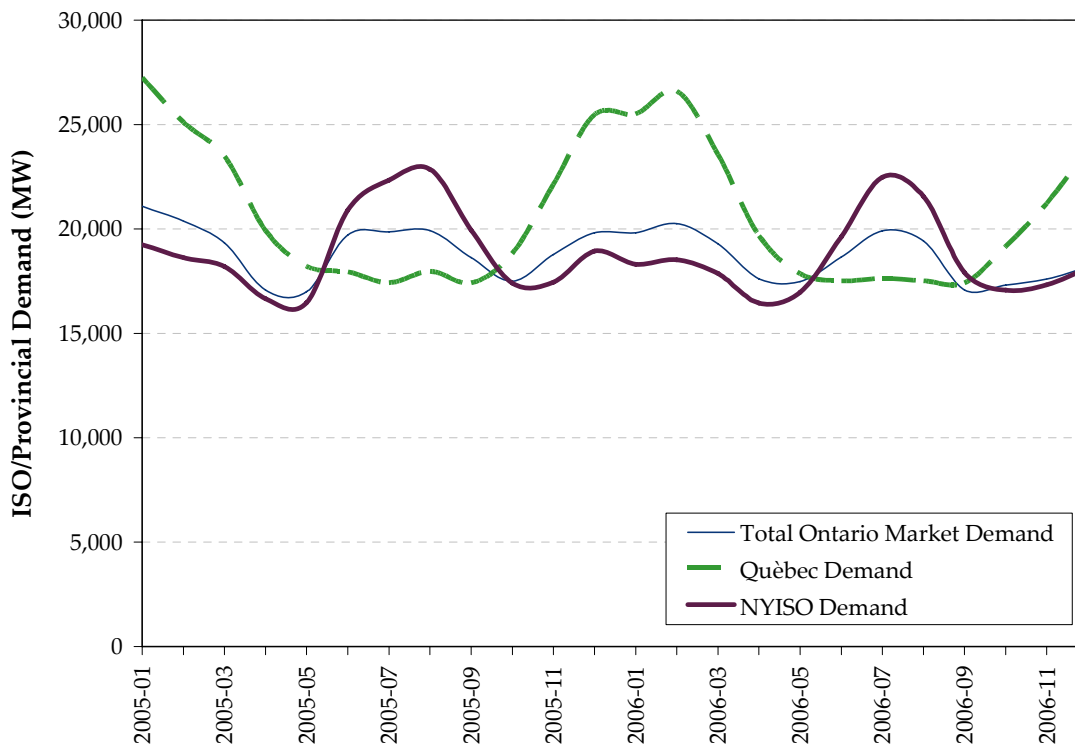
**R1.2 :** For this question, we have analyzed the seasonal patterns of demand and compared the markets in Ontario and Québec. Our analysis shows that they are complementary in the sense that Ontario's demand peaks in the summer months and demand in Québec peaks in the winter months. However, Ontario also has a significant winter load, such that the average monthly demand in the winter months is

very close to that in the summer months. Québec's load does not rise noticeably in the summer months.

Also, we observe that New York has a seasonal pattern similar to that of Ontario, though its summer peak is much more pronounced.

Figure 1.3 show the average monthly electricity demands in the three markets.

**Figure 1.3: Average Monthly Electricity Demand by Province/ISO (2005-2006)**



Data source: NYISO, Ontario IESO, HQD.

**Question 2**

2. **Référence** : Pièce C-12.8-EBMI, rapport d'expert, page 20.

**Préambule :**

« *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. »*

**Demandes :**

2.1 Veuillez élaborer sur les variables pouvant influencer le risque de congestion aux interconnexions (par exemple mais sans s'y limiter : capacité de production croissante d'Hydro-Québec Production qui est un acteur dominant sur les interconnexions, capacité accrue de transport entre le Nouveau-Brunswick et la Nouvelle-Angleterre, nouvelle interconnexion entre le Québec et l'Ontario, etc.).

**R2.1 :** A number of factors could influence the risk of congestion on the interconnections between Québec and other markets. These include, among others,

- Increases in Hydro Québec Production's (HQP) capacity,
- The recent increase in interconnection capacity between New Brunswick and New England,
- The expected increase in interconnection capacity between Ontario and Québec,
- Increased exports of electricity from renewables, particularly wind, from New Brunswick and PEI to New England; and
- Increases or decreases in electricity demand in Québec.

Without having made a complete analysis of the risk of congestion, we want to provide you with comments pertaining to certain of these factors and how they may act on the risk of congestion in expected directions:

- Increases in HQP's production capacity will increase supply in Québec. Other things equal, if this increased supply is not contracted to Québec consumers or to HQD, it will increase the availability of electricity for export over the interconnections. This will increase the risk of congestion on those interconnections. HQP currently has projects under construction which are scheduled to come into service during the 2008-2011 time frame: Rapide des Coeurs, Chute Allard, and Eastmain 1A/Rupert Diversion.
- Export (and import) capacity between New Brunswick and New England increased in December, 2007 with the opening of the International Power Line, a new transmission line between Maine and New Brunswick. Such an increase in import capacity, other things equal, can be expected to decrease the risk of congestion on the interconnections.

However, as the Régie de l'énergie noted, HQD is a dominant actor on the interconnections. HQD has all of the firm transmission rights on this new line. Therefore, the impact of this new line on the availability of interconnection capacity will depend on the intensity with which HQD exercises its transmission rights. The more uncommitted generation capacity owned by HQD, the more it

is likely to use those rights and the greater the risk of congestion on the interconnection.

- A new 1250 kV connection between Ontario and Québec is currently under construction. This line, and associated transmission upgrades within Québec, will increase the transfer capability between the two provinces and therefore reduce the risk of congestion in the interconnection. It is anticipated to be in service in 2009.

However, the dominance of HQP could mitigate the impact of these two new interconnections. HQP owns all 300 MW of the firm transmission rights on the International Power Line between New Brunswick and Maine and all of the firm transmission rights on the new interconnection between Ontario and Québec which is currently under construction. HQP's ownership of these transmission reservation rights could reduce the ability of other parties to access these interconnections.

- Prince Edward Island has the potential for significant development of renewable generation using wind turbines located in its coastal areas. Total electricity demand in PEI is relatively low. The developers and potential developers of these renewable resources may look to export the electricity through New Brunswick to New England, where, in addition to electricity sales, they could receive payment for the Renewable Energy Credits (RECs) they create. To obtain these credits, they must deliver the electricity to New England. This generation adds to the possibility of congestion on the interconnections between New Brunswick and New England. For example, the West Cape Wind Farm exported power and sold RECs to New England in May, 2007. This project is expected to complete construction in 2008.
- Any increase in electricity demand in Québec would reduce the risk of congestion on the interconnection (in the direction of exports from Québec) by reducing the amount of energy available for export. Conversely, a decrease in electricity demand in Québec would increase the risk of congestion on the interconnections in the direction of exports from Québec.

2.2 Veuillez indiquer si les risques de congestion aux interconnexions entre le Québec et les réseaux voisins peuvent changer durant la période couverte par l'analyse, soit de 2008 à 2011. Veuillez expliquer votre réponse.

**R2.2 :** The risk of congestion on the interconnection will change over the period from 2008 to 2011. Three of the factors cited in the response to R2.1 (HQD generation capacity, the new interconnection with Ontario, and PEI wind generation), as noted in that response, will change during this time period. Others may also change.

2.3 Le cas échéant, veuillez produire une analyse de sensibilité de votre évaluation des revenus de revente en fonction de la variabilité des risques de congestion.

**R2.3:** The prices in Table 4.7 of the Report,<sup>3</sup> which were used to compute the estimated revenue in Table 4.8 of the Report,<sup>4</sup> were adjusted by the congestion effects shown in Table 4.6 of the Report.<sup>5</sup> The price impacts shown in Table 4.6 were based on the price differentials in all hours and those hours when there was at least 300 MW of unused capacity on the interconnection.<sup>6</sup> To perform a sensitivity analysis on the impact of congestion, therefore, we have repeated the analysis of Table 4.6 using periods when there was at least 200 MW and at least 400 MW of unused capacity on the interconnection. This methodology measures the sensitivity of the revenues to the degree of congestion on the intertie by computing the revenues at three different levels of intertie availability –two new levels of 200 and 400 MW as well as the 300 MW level previously assumed.

**Table 2.1: Potential Losses Due to Congestion by Availability**

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Average
<b>NYISO (&gt;200 MW Available Capacity)</b>													
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	<b>\$57.58</b>
Uncongested	\$49.05	\$69.34	\$57.27	\$42.86	\$45.68	\$53.32	\$54.35	\$59.35	\$53.35	\$59.12	\$57.47	\$79.49	<b>\$56.72</b>
Congestion Loss	\$0.86	\$0.10	\$1.85	\$1.26	\$2.07	(\$0.37)	\$0.80	\$1.92	\$0.16	(\$0.61)	\$2.22	\$0.00	<b>\$0.86</b>
<b>NYISO (&gt;400 MW Available Capacity)</b>													
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	<b>\$57.58</b>
Uncongested	\$48.10	\$69.33	\$56.49	\$40.05	\$46.30	\$50.29	\$52.86	\$58.06	\$53.18	\$58.21	\$52.21	\$79.46	<b>\$55.38</b>
Congestion Loss	\$1.81	\$0.11	\$2.63	\$4.07	\$1.46	\$2.66	\$2.28	\$3.22	\$0.33	\$0.30	\$7.47	\$0.03	<b>\$2.20</b>

Data Source: NYISO

Table 2.1 shows the results of this analysis. The first line in each group shows the average price, by month, for all hours. The second line in the upper group shows the average price, by month, for only those hours when at least 200 MW of intertie capacity was available; that is, those hours when the interconnection was not fully congested. In general, it can be expected that the greater the electricity demand in New York, the more congested the interconnection will be and the higher the prices will be. The periods of greater congestion are therefore expected to be the periods of higher prices. Therefore, the average shown on the second line does not include the highest-price hours, so this price is lower than the all-hours price. The price differential occurs because congestion reduces the ability of the exporter to cash in on those high-price hours. The lower group shows a similar calculation for the case when the line is even less congested, with at least 400 MW of interconnection capacity available. The results in Table 2.1 show that the more high-price hours the exporter can sell into, the lower the price differential. This table is analogous to Table 4.6 in the Report.

<sup>3</sup> Piece C-12.8-EBMI, rapport d'expert, pg. 20.

<sup>4</sup> Ibid.

<sup>5</sup> Piece C-12.8-EBMI, rapport d'expert, pg. 19.

<sup>6</sup> Ibid.

The next step in the analysis is to compute the projected prices to HQD given the different hourly prices in New York. These are shown in Table 2.2 below. It is analogous to Table 4.7 in the Report, and shows the prices expected by HQD, net of the impacts of congestion, transmission losses and transactions costs.

**Table 2.2: Projected Prices to HQD Showing Sensitivity to Congestion (\$US/MWh)**

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Average
<b>Projected Electricity Price to HQD for Sales @ NYISO-HQ Interface (&gt;200 MW Available Capacity)</b>													
2008	\$62.44	\$61.25	\$41.78	\$63.00	\$64.83	\$69.94	\$76.26	\$74.76	\$76.05	\$72.26	\$72.62	\$78.54	\$67.81
2009	\$82.80	\$85.32	\$78.73	\$59.30	\$60.15	\$65.06	\$70.80	\$69.34	\$70.67	\$67.22	\$67.54	\$73.79	\$70.89
2010	\$78.34	\$80.86	\$74.19	\$56.98	\$57.99	\$62.86	\$68.40	\$66.94	\$68.26	\$64.96	\$64.65	\$70.93	\$67.95
2011	\$74.16	\$78.07	\$71.27	\$56.35	\$57.51	\$62.41	\$67.95	\$66.50	\$67.86	\$64.56	\$63.67	\$69.97	\$66.69
<b>Projected Electricity Price to HQD for Sales @ NYISO-HQ Interface (&gt;400 MW Available Capacity)</b>													
2008	\$61.49	\$61.24	\$41.00	\$60.18	\$65.44	\$66.91	\$74.77	\$73.47	\$75.88	\$71.34	\$67.37	\$78.51	\$66.47
2009	\$81.86	\$85.31	\$77.95	\$56.48	\$60.76	\$62.03	\$69.32	\$68.05	\$70.50	\$66.30	\$62.28	\$73.76	\$69.55
2010	\$77.39	\$80.85	\$73.41	\$54.17	\$58.61	\$59.83	\$66.92	\$65.65	\$68.09	\$64.04	\$59.40	\$70.89	\$66.60
2011	\$73.22	\$78.06	\$70.49	\$53.53	\$58.12	\$59.38	\$66.46	\$65.20	\$67.68	\$63.64	\$58.42	\$69.93	\$65.35

Finally, the impact on revenue to HQD is computed in Table 2.3. It indicates that the total revenues are not sensitive to the range of congestion shown here. The difference between the 200 MW case and the 400 MW case is under 2% in all cases. This table is analogous to Table 4.8 in the Report. The revenues reported in that Table fall between the values reported for the sensitivity cases.<sup>7</sup>

**Table 2.3: Estimated Revenue from Sale of Surplus Electricity at NYISO-HQ Interface (\$US)**

	>200 MW of Available Capacity	>400 MW of Available Capacity
<b>\$million</b>		
2008	\$156.5	\$153.2
2009	\$194.2	\$190.1
2010	\$81.3	\$79.9
2011	\$108.8	\$106.4
<b>\$/MWh</b>		
2008	\$70.0	\$68.5
2009	\$67.2	\$65.7
2010	\$64.9	\$63.8
2011	\$63.8	\$62.3

<sup>7</sup> Piece C-12.8-EBMI, rapport d'expert, pg. 20.