Manitoba Hydro 2010/11 & 2011/12 GRA
Book of Documents Volume 3 – PUB Counsel

INDEX

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Book of Documents Volume 3 – PUB Counsel

INDEX

51

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MANITOBA HYDRO

2002-2004 DROUGHT RISK MANAGEMENT REVIEW

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Prepared by Tim J. Simard and Jim R. Joyce
Principal Consultants, RiskAdvisory
610, 1414 – 8th Street SW
Calgary, Alberta, Canada T2R 1J6
Tel: (403) 263-7475
Fax: (403) 263-2945
www.riskadvisory.com

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Table of Contents

Scope of Report

RiskAdvisory has been retained by Manitoba Hydro ("Hydro" or "the Company") to review the Company's energy portfolio management activities as they pertained to the drought experienced by the Company from 2002-2004 and prepare a report on its findings.

Specifically, the analysis will focus on Hydro's responses to the drought including forward purchases of electricity, book-outs of physical electricity, the acquisition of natural gas storage, call and put option transactions on electricity and natural gas, natural gas tolling transactions, and the subsequent unwinding of natural gas transactions.

The review will also look at the decision-making process deployed by Hydro in acquiring the various risk management products.

RiskAdvisory interviewed key Hydro personnel involved in the drought management including Executives, Management, the Power Trading Department, and the Operations Planning staff.

RiskAdvisory reviewed key pieces of data including

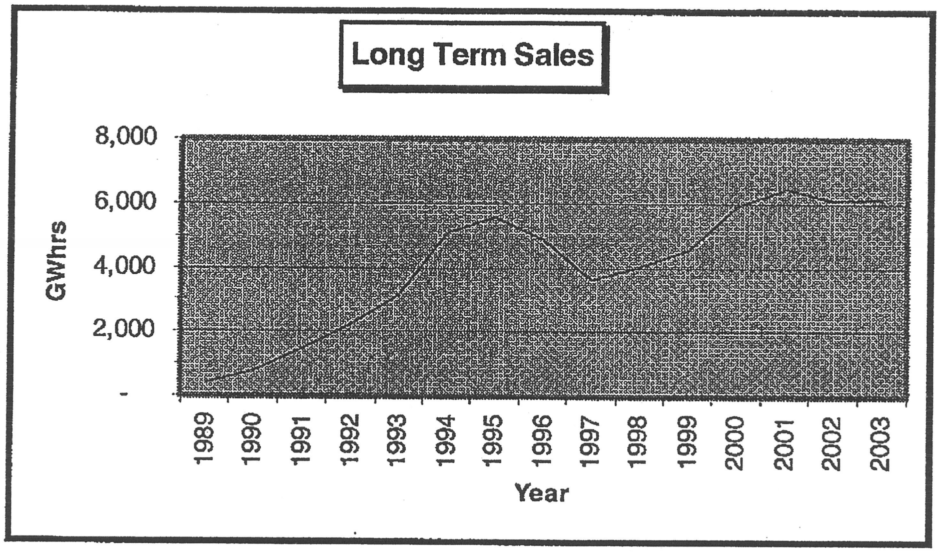
- Master Purchase and Sale Agreements;
- Electricity Transaction Confirmations;
- Natural Gas Transaction Confirmations;
- Storage Injection and Withdrawal Schedules;
- Optic Transaction Confirmations;
- Corporate Import/Export Policies and Procedures;
- Export Strategy Documentation;
- Analytics behind decisions;
- Correspondence (Internal and External).

Background

In 1989-1990, Manitoba Hydro suffered its third worst drought since 1912 when records were first retained with respect to hydrological input data. Hydro did not suffer another drought until the spring of 2002. By June of 2003, Manitoba Hydro was experiencing the second lowest water inflows since 1911 and was in drought conditions until April 2004.

The single biggest financial loss in the Company's history occurred in 1989 when they experienced a $28mm dollar loss. In the '03 drought, the Company lost $436mm. The major factors that can be attributed to the substantial difference in financial performance from the '89 drought to the '03 drought include:

- Significant increases in long-term fixed price export sales. In 1989, the Company had 423 GWhs of long-term commitments. In 2003, the Company had over 6,100 GWhs of long-term commitments (see figure 1 for historical perspective). These sales generate a substantial amount of revenue for the Company in average, above average, and even moderately below average water flow years. The reverse is true in significantly below average years. In drought, the Company does not have enough generation to meet domestic Manitoba load and fulfill their obligations under the long-term export sales arrangements without draining reservoirs and risking energy shortages should drought conditions persist longer than anticipated. In order to minimize the risk during drought years, Hydro must use alternate sources of supply to meet its export sales volumes.



- The wholesale electricity market has undergone deregulation and the majority of energy is now transacted under market-based rates as opposed to cost-based rates that were in place in 1989. However, although electricity transacted at market-based rates has to be "fair and reasonable", the "fair and reasonable" test is so broadly defined that it cannot be relied upon to eliminate the risk of "shortage pricing". As an example, prices at Cinergy in the Midwest have traded above $5,000 per MWh on several occasions over the past five years. Shortage pricing occurs when electricity sellers do not have sufficient power to sell into the marketplace to meet demand and are therefore able to command significant premiums over the cost of the most inefficient unit in the marketplace.

- Most of Hydro's market activities are with the NERC region known as MAPP. MAPP has a significant amount of hydro, coal, and natural gas fired units. When the region experiences a drought, "shortage pricing" may exist during peak demand periods. The likelihood of shortage pricing conditions in MAPP is exacerbated by the fact that limited transmission availability from other NERC districts into MAPP, and between northern and southern MAPP, constrains the ability to acquire lower-cost electricity from neighbouring regions.
- Manitoba Hydro has gas-fired generation in its mix of generation assets. These units did not exist in the '89 drought but now account for approximately 400 MWs of generation with an above-market heat rate of approximately 12.5. This makes Hydro's units less efficient than the vast majority of generating units in the region. The initial capital investment in these plants was based on the understanding that they would be used for reliability purposes and the trade-off was accepted between unit efficiency and upfront capital costs. As such, the units will only be turned on in emergency situations, drought conditions or when shortage pricing exists in the region where significant premiums are being asked from the marketplace.
- Natural gas prices were (and still are) trading at very high levels relative to historical prices. For much of the period from 1989 to 2002, Canadian natural gas prices traded from $2.00 to $3.00 per gigajoule ("GJ"). Since 2002, gas prices have been trading above $5.00/GJ with occasional short-term spikes above $9.00. This served

to make it more expensive to run Hydro's gas units and increased the cost to cover export sales commitments given the positive correlation between regional gas and power prices.

It should be noted that while the Company was feeling the financial impact of the drought, at no point was Manitoba load in immediate danger of being curtailed.

The '03 Drought

The '03 drought actually began in the summer of 2002. June 18, 2002 was the last major storm that Manitoba Hydro experienced until March '04. By mid-July '03, the Winnipeg River Basin was at 40% of normal production. Manitoba Hydro did draw some water out of the reservoirs during the winter of 2003. However, it was evident that there was very little snowpack in the winter and the failure of normal spring rains would result in a serious drought and significant losses.

In January '03, the Power Sales and Operations Division had estimated that the potential reduction in net revenue mainly caused by a drought and continued high natural gas prices could reach as much as $700 million. This figure was discussed with the Company's executive team.

The Manitoba Hydro Board of Directors was apprised of the potential for a drought in January 2003. However, the Corporation's financial exposure was not discussed in detail at that time given the probability of such an extreme deterioration in net revenues was still low. The Board of Directors was advised that there was nothing to indicate that the spring and summer rains would not be normal and that it was still premature to begin purchasing natural gas or power to hedge Manitoba Hydro's drought exposure.

By the spring of '03, although there were near-normal water conditions in the most westerly water sheds, elsewhere water conditions were extremely poor and overall reservoir levels were at their lowest point in 27 years. By the end of June '03, the Company was witnessing its second lowest water inputs in the 92 years of history on record (worst year on record was 1940/41). It was during the second quarter of '03 that a drought management plan was put in place.

The Drought Management Plan

The premise of the Drought Management Plan was to avoid expenditures as long as possible while at the same time ensuring that the ability to serve Hydro load was not jeopardized through the maintenance of sufficient hydro reserves.

The key points to the plan were:

- Use the river flows to meet the obligations of the Manitoba load;
- Maintain hydro reserves as per the Operations Planning Criteria discussed in the next section. It should be noted that while costs may be incurred during the current period by deferring the use of hydro reserves until a later period, the net cost effect of this decision should include the revenue generated in the future period.

These incremental revenues would not have been earned if the reserves had been consumed during the prior period;

- Gradually respond to drought conditions as necessary on a largely mechanistic basis tied to updated volumetric forecasts;
- When necessary, use the U.S. wholesale market to buy back the Company's export market obligations. Since the Company does not have the ability to transact in the US, the Company would look to enter into bookouts[1] with their export sales customers.
- Delay expenditure commitments as much as possible to allow for the mean-reverting nature of hydrological inflows. History shows that while droughts do occur, their length and severity cannot be determined on an upfront basis. If the Company had booked out transactions immediately and the rains had arrived in late spring or early summer, the Company would have incurred significant opportunity costs in a non-drought environment.
- Develop Operations Planning Criteria for determining the energy surpluses/shortfalls in an extended drought condition.

The Company's executives approved the Drought Management Plan in May '03.

[1] A "Bookout" is a transaction between two counterparties that offsets all or part of a previous transaction that had been entered into between those two counterparties. The physical delivery requirements of the original contract covering the agreed-upon bookout volumes are offset with the bookout transaction. Since the delivery of the product is perfectly offset in the two transactions, there is only a cash payment made from one party to the other party. The cash difference represents the difference between the contract price in the original transaction and the contract price in the bookout transaction.

Operations Planning Criteria

An Operation Planning Criteria was developed in May '03. The model assumptions for planning purposes were:

- A 5% worst-case water supply for the balance of the year;
- An extremely cold winter (10^{th} percentile winter);
- Must be able to survive a drought in '04 given '03 drought conditions. In other words, the Company required sufficient water in storage to last another year assuming lowest historical flows. The requisite hydraulic reserves would be determined on at least a weekly basis recognizing updated snowpack conditions;
- The Company intended to meet all firm Export Sales obligations. This would be done through bookouts or through physical delivery from the gas plants and/or 3^{rd} party purchases.

The Planning model would look at the future on a weekly basis for the first 90 days and monthly thereafter.

Operations Planning Criteria Results

In May '03, the Company ran its Operations Planning Model with the drought management criteria for the first time and the results showed a tremendous shortfall of energy in the fall and winter periods. The amount of the shortfall was up to 1,800 MWs in each hour with a maximum between 700,000 and 800,000 MWhs in each month.

The Company justifiably believed that the consistent purchase of 1,800 MWs on the spot market would lead to at least two negative consequences:

- Shortage-pricing[2] in the marketplace; and
- Transmission constraints on the northern tie line.

Given that Manitoba Hydro is usually a seller in the spot market, the shortage-pricing factor would be exacerbated once the market sensed that Manitoba Hydro was a large buyer.

Fears of transmission constraints were brought to bear in the winter of '04 as there were several periods of transmission overload in southern MAPP when Hydro purchased 1000 MWs. The capability to run 400 MWs of gas-fired generation was needed to serve domestic load during these periods transmission system overload. This led to a requirement to plan for natural gas purchases for delivery in the winter of '04.

The results of the Operations Plan led to a plan to acquire natural gas for winter deliveries and to execute a series of complicated bookouts with customers on Hydro's existing export sales.

[2] Shortage pricing occurs when the marketplace determines that a market participant is in dire need of buying or selling the underlying commodity. In this case, the Company would be short and in dire need of buying large quantities of energy. Sellers would quickly detect the Company's circumstances and begin charging incrementally higher prices for the commodity. Shortage pricing at the Cinergy delivery point (one wheel away from Manitoba Hydro) has reached in excess of $5,000 on a handful of occasions over the past 5 years.

Bookouts of Export Sales

In 2003, Manitoba Hydro had over 6,100 GWhs of long-term sales[3]. Under the Operations Planning Criteria, these sales were in danger of not being met if the Company experienced an extended drought. Beginning in late spring '03, the Company embarked on a program to approach all of their customers with long-term sales, looking to enter into agreements with them to bookout as much of the sales as possible from the fall of '03 through the spring of '04.

Manitoba Hydro had a great deal of success in booking out the seasonal non-peak periods of these transactions with the majority of its customers. Bookouts of summer transactions were purposely avoided with the recognition that Hydro's customers relied on the security of the Company's summer supplies. A move to reduce these summer supply commitments in the forward markets could have had long-term negative repercussions on Hydro's reputation for reliable electricity deliveries.

In some cases, due to the internal policies of the Customers, bookouts were not possible. In these cases, the Company worked with suppliers to divert power so that the commitment was offset even though a true bookout did not exist.

By September '03, the majority of the commitments had been eliminated in the market. However, there still existed a gap of approximately 650 MWs of on-peak exposure that needed to be covered.

[3] "Long-term sales" are sales that have durations of longer than 1 year.

It was at this time that Manitoba Hydro and [redacted] reached an agreement whereby MH purchased a [redacted] MW call option from [redacted] with a strike price tied to [redacted] actual cost of gas multiplied by a heat rate of 12.5. The contract term was from [redacted] '03 to [redacted] '04. It would be reasonable to assume that [redacted] cost of gas correlates very highly to the Demarcation delivery point on the Northern Natural Gas Transmission Line.

The Company also purchased a [redacted] call option from [redacted] This transaction had a strike price of [redacted] per MWh plus [redacted]' fuel cost adjustment. The contract term was from [redacted] Even though the plant was in the [redacted] owned firm transmission from the plant to [redacted] so that the final delivery point was [redacted]. The nature of the [redacted] fuel cost adjustment meant that the strike price of this option was below prevailing market rates most of the time, resulting in the Company's exercise of the option even in those periods where physical electricity was not required to meet its commitments. The power purchased under this option was then assigned to [redacted] for subsequent resale.

One of the hindrances in covering the export sales was the lack of market liquidity at the delivery point underlying these sales contracts. All of the Company's export sales occur at the US/Canada border, largely driven by financial considerations. When the Company is required to offset these positions, it is necessary to take into account the lack of liquidity at the delivery point. Hydro is not authorized to buy and re-sell electricity in the US because it does not have a Power Marketers Authorization ("PMA") from the

Federal Energy Regulatory Commission ("FERC"). With this in mind, the Company entered into these two call options as the best alternative taking into account deliverability and reliability concerns.

These two transactions left the Company with minimal power price exposure over the winter '04 period. The effect of the option transactions served to convert Hydro's exposure from illiquid electricity markets to more liquid natural gas markets through the winter months. Coupled with potential natural gas requirements for the Company's plants in Manitoba, this led to a significant exposure to winter gas prices.

Natural Gas Requirements

Based on the Operations Planning Criteria developed in May '03, the Company determined its winter gas requirements for its plants to be the following:

Table 1

Month	Required Gas Volumes (Dth) May 21, 2003 Power Sales & Operations Report	Required Gas Volumes (Dth) June 11,2003 Power Sales & Operations Report
Nov '03	270,000	806,000
Dec '03	1,030,000	2,247,000
Jan '04	1,220,000	1,896,000
Feb '04	1,230,000	1,871,000
Mar '04	1,230,000	1,803,000

Total Winter	4,980,000	8,623,000

As can be seen in Table 1, the output of the Operations Planning Model can show significant changes in short periods of time as a result of shifts in forecast hydro availability. (Table 1 references requirements for the Company's own gas-fired generation as the forecasts pre-date Hydro's option arrangements with [redacted] and [redacted]. It was for this reason that the Company instituted a "just-in-time" hedging policy for its natural gas requirements. The plan was to execute one-sixth of its requirements each month from May to October. This would defer the expenditure as long as possible in an effort to capture any significant change in water flows.

Once the power call options were signed in September with [redacted] and [redacted] an additional gas exposure was layered on. With only two months until the winter season, those incremental gas risks had to be managed expeditiously. The gas requirements for the power call options were as follows:

Table 2

Month	Required Gas Volumes (Dth) Sep 18, 2003 Power Sales & Operations Report
Nov '03	1,651,000
Dec '03	3,128,000
Jan '04	2,919,000
Feb '04	2,451,000

Mar '04	202,000
Total Winter	10,351,000

Natural Gas Hedging Arrangements

In March '02, Manitoba Hydro entered into a Fuel Supply and Fuel Management Services Agreement ("[redacted] Agreement") with [redacted] This contract allowed Manitoba Hydro access to natural gas expertise on an intermittent basis when required. The [redacted] Agreement provided a cost-effective alternative to the establishment of an internal gas procurement function whose expertise would only be called upon during drought year scenarios.

The [redacted] Agreement covered a range of functions and services:

- Gas supply, including the resale of any excess gas supply;
- Gas Delivery Services to the Centra/TCPL receipt point;
- [redacted]
- Pipeline nominations;
- Pipeline and storage balancing;
- [redacted]

- Fuel Management Services [redacted]

The [redacted] agreement was, in part, an exclusive agreement between the Company and [redacted] This meant that the Company was precluded from acquiring gas supply or other gas services from other market participants for Manitoba Hydro plants. No such exclusivity arrangement was in place related to the Company's U.S. activities.

Once the results of the Operations Planning Model were accepted, the Company realized that it had a large exposure to rising natural gas prices for gas deliveries for the winter '04. The Company initiated conversations with [redacted] and discussed alternatives with respect to the management of the gas exposure. Subsequently, Manitoba Hydro embarked on a gas acquisition strategy that would cover the exposure to gas prices and the use of interruptible transport on TCPL.

The first hedging agreement that the Company entered into was in late May '03 and by the end of May, the Company had acquired a total of 1,489,600 Dths of natural gas at AECO for the winter period at a fixed price of US$5.656/Dth. This covered approximately 30% of the total expected winter requirements. This transaction was a physical purchase of natural gas for deliveries at AECO of 9,800 Dths/day from Nov. 1/03 to Mar. 31/04.

Subsequently but also in May, a decision was made to acquire 1.5 Bcf of natural gas storage at the Union/Dawn facility in Ontario. The storage allowed for flexible injections and withdrawals and also allowed for a combination of firm and interruptible withdrawals. If the Company did require gas supply on any given day during the winter, it knew it had several options in getting the gas to the Centra/TCPL delivery point including backhauls or diversions. The storage contract was acquired at a cost of $1,125,000. The Company also had to purchase gas to inject into storage. This was done during the month of June with injections ranging from 30,000 Dths/day to 75,000 Dths/day.

The volumes of gas injected each day were tied largely to a mechanistic approach based on the required levels of storage gas as per the Natural Gas Requirements report issued on at least a weekly basis by the Operations Planning Department. [redacted] injection and deliverability information were also considered in the injection decision-making process. The net result was an average injection price of $6.102. If the Company had injected ratable volumes each day, at the same price levels, the average cost of gas would have been $6.127. On 1.5bcf of gas, this represented a savings of $37,500.

In late June, the decision was made to acquire an additional 2 Bcf of Union/Dawn storage at a cost of $1.5mm. Once again, the Company needed to acquire the natural gas and they did so from July 1 until September 30. The injections were done much more ratably than the first series of injections and were done under the following schedule:

Table 3

Dates	Volume (Dths/day)

July 1-July 17	32,300 Dths/day
July 18-July 31	19,000 Dths/day
Aug 1-Aug31	28,500 Dths/day
Sept 1-Sept 30	10,490 Dths/day

As can be seen in the above table, there was some discretion on how much to inject each month. The average price of the 2 Bcf was $5.189/Dth. If the Company had injected ratable volumes each day, at the same price levels, the average cost of gas would have been $5.109. On 2.0bcf of gas, this represented an additional cost of $160,000. It should be noted that the Company did not use discretion in trying to predict gas prices, but used discretion in timing as a result of strategy to delay purchasing gas as long as possible in an effort to take advantage of any rainfall that may occur. Also, it should be noted that the Company did not necessary embark on a strategy to inject the maximum amount of storage, but to inject their forecasted requirements.

The combination of the two storage transactions and the AECO hedge represented a purchase of 5.0 Bcf of gas or roughly 60% of the potential requirements for the upcoming winter season. It was felt that the remaining balance would be left unhedged in order to avoid the costs if the gas supply was not necessary. Given the uncertainty with the supply situation, this was a rational and prudent approach.

In July '03, the Company was sitting on 5.0 Bcf of fixed price natural gas. While this provided a very good hedge against rising prices in the winter if the Company required the gas, it also opened up the Company to the risk of a downward price movement should the Company not require the gas. The uncertainty of the water situation led the Company to purchase physical put options to protect against falling prices.

From July to September '03, the Company entered into a series of put options that totaled 2.55 Bcf. The put options had to be exercised at the beginning of the month and the strike prices ranged from US$5.25 to US$5.75 per Dth and cost US$485,500. They were all options that gave Manitoba Hydro the right to put gas to [redacted] at Union/Dawn in exchange for the strike price. Each of the options was for the January to March time period and could be struck at the beginning of each delivery month.

This protected Manitoba Hydro from a fall in gas prices until the beginning of each month. However, it did not protect the Company from a subsequent fall in prices during the delivery month.

Once the Company purchased the two power call options in the US, it was exposed to rising natural gas prices should they require the power. The decision was made to acquire 4.5 Bcf of natural gas storage at three locations in Oklahoma and Kansas. These locations are in close proximity to Northern Natural's Demarcation delivery point. Because it was so late in the injection year, no open storage was available. [redacted] had therefore already injected the natural gas into the storage fields. Therefore the gas was transferred at a price of US$5.45 to Manitoba Hydro for a gas cost of

US$24,525,000. In addition the cost of storage asset rights was US$3,800,000.

Once again, the Company was hedged against rising prices should it require the gas, but was left exposed to falling prices should the gas not be required. The Company purchased a financially settled put option against NYMEX settlement prices for 3.65 Bcf for a cost of US$1.6mm. This protected the Company against NYMEX prices falling below the $5.45 price level for the January to March timeframe. Again, these puts were monthly settled options. They protected the Company from falling prices until the beginning of the month, but left the company exposed to movements in the gas price after the first of the month. The Company did look at daily settled options, but they were deemed to be uneconomic.

Unwinding Hedges

The first hedge to be unwound was the initial gas supply hedge with deliveries at AECO. Once the storage was put in place, Manitoba Hydro reviewed the merits of their initial hedge at AECO. There were several issues with this hedge that made it a very inefficient hedge. The issues included:

- The delivery was a fixed volume per day. The likelihood of the Company requiring the gas each day was very small. However, on days that the gas was required, the Company would require up to 80,000 Dths/day. If the Company continued to buy hedges in this fashion, the exposure to falling prices when gas had to be re-sold would have been greater than the exposure to rising prices in the absence of a hedge.

The delivery location was NIT (Nova Inventory Transfer). [redacted] could not guarantee that they could deliver the gas to the Centra/TCPL delivery location. This created a very low risk that on an extremely cold day in the winter, the Company would not receive delivery of the physical gas at its plants.

In July '03, while working with [redacted] to continually develop an adequate gas management plan for the winter, the Company decided to sell the previously AECO acquired hedges. The sale of the physical purchase was made at a price of US$4.615. This represented a loss of $1.041/Dth for a total loss of approximately $1.5mm. This loss was taken to avoid future losses if prices fell further and the hedges were not required. Also note that the second tranche of Union/Dawn storage that was acquired by Hydro was viewed as a replacement for the physical purchase hedge. The original physical purchase in effect acted as a hedge of the potential cost of injecting storage from the timing of the initiation of the physical purchase in May to the acquisition of the storage in late June.

As the Company continued through the winter, Operations Planning would update the hydro conditions on at least a weekly basis and forecast gas requirements through the winter. Each storage contract was constrained by having to have 100% of the gas withdrawn by March 31 '04. There were also daily limitations on how much firm and interruptible gas could be withdrawn under each contract. The Power Trading Department would get updated numbers from the Operations Planning Department and would analyze the future gas needs weighed against the need to withdraw all the gas by the end of the withdrawal season.

Beginning in January '04, the Power Trading Department began selling off the excess natural gas. They did this first by determining if the put options were in the money[4]. If they were in the money, those options would have been exercised. However, most of the options expired out of the money and as such, the Company ended up selling the excess gas into the daily-spot or month-ahead market.

The majority of the gas was sold in the daily-spot market. This was done at fixed prices for the Union/Dawn storage gas and at the Gas Daily index for the US storage gas. The balance of the gas was sold on a monthly fixed price basis and delivered on a daily withdrawal basis once it was deemed surplus.

Once gas was deemed to be surplus under the Operations Planning Criteria, the Company exercised some degree of discretion when making these sales taking into account conditions in the gas marketplace and [redacted] understanding of market developments. The Company did not hold excess gas positions for an extended period of time after being notified of the excess position from the Operations Planning Department.

[4] The put options would be considered in-the-money if the monthly index price underlying the put contracts settled below the strike price of the puts.

Observations and Recommendations

The following represents the observations and recommendations of RiskAdvisory with respect to the actions that Manitoba Hydro undertook to manage the drought of 2003-2004.

General

We believe that for the most part, Manitoba Hydro managed the drought in a very commendable and prudent manner.

RiskAdvisory has worked with several hydro operators and gas storage operators in the past. It is difficult enough to manage gas storage when you know what your starting point and end point will be. The key to managing that type of storage is optimizing the injection and withdrawal. The problem with the Hydro storage is you don't know the injection schedule or the total amount of energy that you will have when you start the winter season. This results in making estimations that include several large-impact assumptions. The most material assumptions surround the timing and magnitude of precipitation. This cannot be answered with any degree of certainty, but the water flow analysis and planning curves that Manitoba Hydro uses appear to be credible solutions. This is an area that the Company focuses a great deal of effort on enhancing and RiskAdvisory supports a continuation of this effort.

The losses that the Company experienced could have been over $1 billion[5] if the exposures had not been managed properly. Alternatively, the Company

[5] The loss could have reached this level as a result of purchasing a large amount of power on an hourly basis in shortage pricing market conditions coupled with the potential for high natural gas prices.

may have been forced to drain the reservoirs, creating the risk of delivery shortfalls if the drought had continued. While there were costs associated with the hedging activity, the need to avoid material income swings and maintain balance sheet stability more than outweighed those costs.

Given that the majority of employees responsible for implementing the Drought Management Plan had not had previous drought experience, the ingenuity and intelligence that was shown in creating and implementing the Drought Management Plan exceeded expectations.

The "averaging-in" hedging strategy is a sound strategy for the situation that the Company was in. The uncertainty around the water forecasts and the liquidity considerations of the delivery points at which the Company needed to transact are the most valid reasons for this type of hedging activity.

Bookouts

The use of book-outs for the majority of the power hedges was necessary for this drought. However, RiskAdvisory does have concerns with this approach in the future. Based on years of experience in the energy markets, RiskAdvisory believes that any kind of captive transaction leads to less attractive prices. For example, if a customer of Manitoba Hydro usually buys from Manitoba Hydro, and then is asked to sell to Manitoba Hydro at the same delivery location, that customer is apt to think that problems exist and the only reason Manitoba Hydro would be doing this is that the Company is in some kind of trouble. While the Company made its customers aware that it had other options available, the customers would no doubt still apply a premium to the market for the sale.

The reliance on captive bookout transactions could be reduced in the future with the application for a FERC PMA. Transmission considerations tied to the constraint on Manitoba's import capacity will mean that bookouts cannot be eliminated. However, access to a broader network of buyers and sellers associated with the PMA should create opportunities to acquire and re-sell power with more efficiency. Most notably, contracts would not have to be assigned to third parties, thereby reducing incentive payments to these counterparties.

The PMA application does not come without costs and FERC requirements. The Company may opt not to do this for other corporate reasons. Our recommendation is to study the feasibility of receiving market-based rate authority and weigh the portfolio risk management advantages against the perceived disadvantages.

Storage

The use of storage is often misused as a financial risk management tool. That is because the flexibility that storage provides from a physical perspective is not required to manage many companies' financial and operational risk. That is not the case with Manitoba Hydro.

Because of the Company's need for large amounts of gas at sporadic moments in time, a ratable purchase of natural gas would have the hedger either being tremendously short on days when it did need the gas, or tremendously long on days that it did not need the gas. The volumetric flexibility of storage withdrawals gives the Company the desired amount of supply on a daily basis as it is required.

The Company used a forward purchase of AECO gas as a foothold for a hedge until they could get a proper amount of storage put in place. Again, this is a common way of establishing a hedge at illiquid points.

An alternative to storage as a hedge could be the purchase of call options. The Company analyzed this strategy and it was deemed too expensive relative to the benefits that call options gave them. In fact, by purchasing forward gas, and buying put options, the Company ended up purchasing what are called "synthetic call options". Synthetic options provide the same economic protection as conventional call options. By purchasing the forward, the Company has exposure to falling prices and will benefit in rising prices. When the Company purchases the put option, it will benefit from a fall in prices and simply forfeit the fixed premium if prices rise. The combination of the two structures leaves the Company benefiting from a rise in prices with no downside to falling prices. This is the same economic condition that exists when owning a call option. By using storage as the forward position for the synthetic calls, the Company gained the required delivery flexibility and was protected against upside risk with reduced downside risk.

The problem with the put options that the company acquired was that they expired at the first of the month. Therefore, if the first of the month price was higher than the strike price, the Company would make the choice not to exercise :he option. Once this happened, the Company had exposure to falling prices because there was no put option to give protection and there existed downside risk to the storage gas.

During the '02-'03 time period, a number of gas marketing and trading companies had suspended operations, with a resulting adverse effect on liquidity. Companies were less willing to enter into complex option structures. Market liquidity and the willingness to consider complex transactions have subsequently rebounded. RiskAdvisory believes that Hydro should look at other option strategies as an alternative to storage the next time this occurs.

A very good fit for Hydro would be to purchase daily call options that can be exercised on any day of the winter, but can only be exercised on a limited number of days during the winter (i.e. 40 days out of the 151 winter days). For example, the Company might acquire these options on a volume of 75,000 Dth per day for a total of 3 Bcf of options. Under the monthly settled call option, that 3 Bcf of options would give the Company the ability to call on approximately 20,000 Dth per day. Therefore, the Company would have to buy 3.5 times the amount of options to give it the same protection as the restricted daily call option described above. While the option that gives one the right to select the specific exercise days during the winter is more expensive on a per Dth basis.

RiskAdvisory does not believe this type of option would have been available to Hydro at a commercially reasonable price during the drought year given liquidity conditions in the gas market at the time. This is meant as a recommendation for consideration during the next drought management situation.

Tolling Agreements

RiskAdvisory believes that this was a very innovative hedging mechanism to add additional resources. Essentially, the Company capped the amount of shortage pricing that it would be paying into the market at a [redacted] heat rate. Since the market expectation for a heat rate in the MAPP region for that time period was around 7.0, this tolling arrangement was similar to an out-of-the-money call option that could be struck on a daily basis. Hydro was able to cap the amount of shortage pricing premium that it would see in the market at approximately $30.25 [redacted] gas price per MWh. This is far lower than what could have been experienced in the market if the market determined that the Company was experiencing a major drought. From a hedging perspective, the tolling agreements also served to convert the exposure from daily power price movements, which are extremely difficult to hedge to a daily natural gas exposure where more liquidity and portfolio flexibility exist.

Put Option Strategy

There are two concerns with the put option strategy used by Hydro. First, the Company acquired monthly-settled puts and so Hydro did not have any price protection between the time when the monthly index price was set and the day within the month when the gas was sold out of storage. With the puts, Hydro did obtain protection for the period from the date the puts were acquired to the first-of-the-month index point. This was meaningful protection, but it did not provide complete protection given that there was no insulation against a decline in prices during the delivery month. To offset some of this risk when surplus gas existed and when the puts were in the money, Manitoba Hydro sold the underlying volume at the put strike price eliminating any forward downside on that volume.

If this strategy is employed again, Hydro must ensure that stakeholders are aware that while the monthly puts do protect against part of a potential price decline, the protection is not complete. Second, the NYMEX options that were entered into were not for physical delivery, but were financially settled. The Company does not have a policy in place that authorizes the use of financial options for hedging the power portfolio. There was a solid rationale behind their purchase, but the Company must put in place policies to govern the use of these types of structures. Transactions should not be executed unless they are permitted by Policy, or the Risk Management Committee grants an exception to the Policy.

[redacted]

The [redacted] Agreement is meant to give Hydro access to people with gas market experience and expertise. [redacted] is a highly regarded firm with qualified people and Hydro does have access to those people. RiskAdvisory would not recommend changing the advisory component of the [redacted] Agreement. The contract does contain an exclusivity feature, which Hydro management recognized at the time the contract was signed provided incremental value to [redacted] Given the Company's likely sporadic involvement in gas markets primarily during infrequent drought periods, it was deemed necessary to provide this exclusivity as a further benefit to the natural gas counterparty to ensure that Hydro received superior attention and coverage when the gas market services were needed. Despite the rationale for the inclusion of these exclusivity features, RiskAdvisory does have concerns with this aspect of the contract. These concerns center around competitive pricing, idea generation, and credit.

Under terms of the contract, every gas and storage contract, for Manitoba Hydro plants, signed by Hydro has to be with [redacted] Therefore, there is no way of knowing whether Hydro is getting the best possible price in the market. The Company did however check the pricing from [redacted] against published indices as a reasonableness test. It is likely that [redacted] was able to build in incremental margin on the pricing of its transactions with Hydro because of this captive relationship.

By talking with multiple suppliers, Hydro also has access to a broader suite of market experts with a range of risk management and gas portfolio ideas. RiskAdvisory recommends that Hydro should lever off some of the relationships that Centra Manitoba has developed in the gas marketplace. While it is recognized that Hydro has completely different needs, the Company can benefit from the market intelligence that Centra's relationships provide assuming there are no regulatory impediments for doing so.

The key concern with the [redacted] relationship centers around credit. For the most part, Hydro purchases gas from [redacted] and there exists very little credit exposure with that type of activity. However, the credit exposure went up dramatically when Hydro purchased storage assets from [redacted]. The storage agreements that Hydro entered into are with [redacted] not the storage operator. [redacted] was the counterparty with the storage operator.

Hydro would then buy the gas from [redacted] and inject it into the storage field. At that point in time, [redacted] was legally holding the Company's asset – that asset being the gas. The Storage Operator did not know that it was Hydro's gas. From the Storage Operator's perspective, [redacted] was the owner of the gas. Therefore, if [redacted] were to run into credit problems, the Storage Operator could take control of the gas and sell it in the open market to pay for [redacted] obligations. Hydro 's only recourse would be to launch a claim against an un-creditworthy [redacted].

Although such an event did not happen, Hydro should be aware that they had a significant exposure to [redacted] that should have been backed up by a letter of credit. A better solution yet is to be able to deal with the Storage Operators directly so that Manitoba Hydro retains control and title over the storage gas.

Hydro also incurred significant credit exposure to [redacted] with respect to the put transactions. If gas prices had plummeted and [redacted] was unable to perform on its contractual obligations to Hydro, the credit loss could have been material. A US$2.00 fall in NYMEX and Union/Dawn gas prices below the put strike prices combined with a performance failure by [redacted] would have resulted in the incurrence of a US$12.4 million credit loss.

RiskAdvisory believes that Hydro should continue to engage [redacted] on the advisory side. However, the [redacted] Agreement should be restructured to eliminate the transactional exclusivity. In addition, credit support terms must be negotiated if further transactions are contemplated with [redacted]

Management Reporting

One of the key objectives associated with risk management reporting is the reduction of "surprises" that can have a material impact on revenues and income. A concern with the Hydro drought situation was that there appeared to be an element of surprise among the executive team around the magnitude of losses as they unfolded. While the Power Sales and Operations Division did discuss the potential magnitude of losses with senior management, there was more focus placed on the mean expectation of the forecast revenue, as opposed to the distribution around this mean outcome. The Integrated Financial Forecast ("IFF") projected the expected revenue, and management's attention was tied more to this estimate than the information that was provided around the potential for deviations from this estimate.

RiskAdvisory believes that Hydro needs to improve the management reporting to include the mean cases, but also give sensitivities and probabilities around the mean scenario. These reports should be produced on at least a monthly basis, with more frequent reporting in the midst of a drought scenario. This would provide management with a clearer picture of the worst-case scenario, allowing for enhanced contingency planning and reducing the likelihood of negative surprises.

Establishing Limits

Decisions around the timing of portfolio hedge transactions, the size of these hedge positions and the choice of structure were partially based on quantitative analysis and indications of the potential volume underlying the exposures in both the power and the gas markets. Hedges were established largely to ensure that volumetric exposures were reduced to levels that created comfort within the Power Sales and Operations management group.

RiskAdvisory believes that going forward two alternatives should be considered. First, a Policy document could be drafted that outlines the maximum volumetric exposure that the Company is willing to take to power prices and gas prices. This could be broken down by month and by on-peak versus off-peak positions. The power volumetric limits would be based on the maximum acceptable short position based on a low-water scenario. Gas limits would be based both on a maximum short position, and the maximum long position.

The concern with volumetric limits is that they do not automatically adjust based on volatility conditions in the underlying markets. While a certain volumetric limit may be deemed to be appropriate today, this may not apply in the future if volatility levels have increased or decreased dramatically. The alternative approach is to define a maximum dollar exposure that the Company is willing to absorb during a drought year scenario taken to a 95% confidence interval. A complex risk model would then be used to determine the potential exposure at a 95% confidence interval taking into account movements in gas and power markets, foreign exchange, hydro availability and load fluctuations. If the risk exposure estimated by this model lies below the maximum dollar exposure limit, no hedging would be required. However, if this limit is exceeded, hedges must be established that bring the exposure back within the limit. If hydro, load or market conditions deteriorate further, incremental hedges will be required to keep the Company within its risk tolerance.

Note that the establishment of the maximum dollar exposure limit ties in with the concept of using the balance sheet to self-insure against the drought year scenario. A strong balance sheet will allow Hydro to set a higher maximum dollar exposure limit, resulting in the need for less hedge activity as the drought year scenario unfolds. If one has less room from a balance sheet perspective to absorb material losses, the maximum dollar exposure limit would have to be reduced, resulting in more active use of external hedging mechanisms.

Conclusion

Overall, the Company did an outstanding job in managing the drought. There is an inappropriate tendency to apply 20/20 hindsight to risk management decisions. However, any judgment must be based on market circumstances at the time, and the need to manage both financial and reliability risks. While the Company did incur incremental costs to avoid draining reservoirs, it did so for the sole purpose of protecting the Manitoba consumer from potential outages in the future. As mentioned earlier, the estimate of these incremental costs should be reduced by the incremental revenue generated in subsequent periods through the deferred sale of electricity out of these reservoirs.

Any analysis of Hydro's actions must begin with the understanding that it is impossible to predict the duration of a drought, and sudden changes in water conditions can have a material impact on Hydro's supply portfolio. Against this backdrop is the corporate strategy supporting long-term export sales. History has shown that by terming up these exports as opposed to selling generation excess on a real-time basis, Hydro is able to earn a significant price premium. Also, by entering into long-term contracts with customers in MAPP, Hydro serves to defer the construction of new competing generation facilities in its export market. The downside is that during a drought, the Company will be exposed to significant losses as it seeks to cover positions and maintain reliability. Past experiences have shown that the annual benefits in most years outweigh the risks during a drought. Hydro staff involved in the drought management activities now has additional experience in these operations and lessons have been learned. This will be a large benefit if another drought hits soon. The Company may not have been perfect in the development and implementation of their drought strategy, but the risk-reducing benefits of the hedging strategy far outweighed the implementation cost of the strategy.

52

Report on Risks Faced by Manitoba Hydro in Power Exports.

By

Nalinaksha Bhattacharyya Ph.D

July 4, 2007

Report on Risks Faced by Manitoba Hydro in Power Exports.

Summary of Findings and Recommendations

1. Risks associated with energy exports are:
   a. Market Access Risk
   b. Credit Risk
   c. Foreign Exchange Risk
   d. Forecasting Risk
   e. Over-commitment Risk.

2. Apart from selling surplus power to export markets Manitoba Hydro is also engaged in merchant transactions which are power trading activities. Should the Corporation increase the amount of these activities it may become advantageous to create a wholly owned subsidiary to manage them. In creating a wholly owned subsidiary a clearer risk management process can be developed and pure merchant transactions could be pursued. Separation also ensures that core corporate activities, such as the selling of surplus power, are not exposed to possible taxation laws.

3. When Manitoba Hydro chooses to sell power under long term commitments it obtains a firm price for a specific quantity of power but it also exposes the Corporation to additional risk of selling beyond its capabilities of dependable energy when water flows/reservoir conditions are in or near drought conditions or future domestic load increases are above projections. With the creation of

regional energy markets and the ability to transact available surplus power in real time and day ahead markets the need to have such long term commitments in place is not as important. In the future it may become advantageous to continue to reduce these types of long term sales as a percentage of the corporation's total export sales.

4. Manitoba Hydro uses several different forecasting demand and supply models to determine its energy position. These multiple systems can create problems as there is a greater possibility of error and because they might use different assumptions and methods which conceivably could result in suboptimal decisions. The Corporation should continue to automate the input processes of these models as much as possible and in the future consider a company wide optimization system for these operational decisions.

5. The middle office should be set up under the control of the Accounting and Finance Branch. Two persons are required in the Middle Office-one a commerce graduate and the other a graduate in a quantitative discipline like Mathematics or Statistics with some course credits in Forecasting.

Report on Risks Faced by Manitoba Hydro in Power Exports.

Table of Contents

Report on Risks Faced by Manitoba Hydro in Power Exports.

List of Tables

Report on Risks Faced by Manitoba Hydro in Power Exports.

List of Figures

Report on Risks Faced by Manitoba Hydro in Power Exports.

By

Nalinaksha Bhattacharyya, Ph.D

Introduction

Manitoba Hydro or Hydro for short is the crown corporation owned by the Province of Manitoba and charged with the responsibility of meeting the electricity needs of the province of Manitoba as directed under the Manitoba Hydro Act. The average annual electricity generation is about 30 billion kilowatt-hours of which 98% is generated from hydroelectric sources with the remaining 2% being produced by thermal and diesel generation. In addition to its own generation Hydro also has a commitment under a long term power purchase agreement to buy all electricity produced by the province's first privately owned wind farm located in St. Leon. The electricity produced by this wind farm will not significantly alter the supply mix of the utility.

As directed under the Manitoba Hydro Act, Hydro is mandated to meet the electrical power requirements of the province. However, the utility has generating capacity over and above that needed to meet this Manitoba demand and exports the surplus generation. Table 1 shows the level of energy export by Hydro for the years

1997 to 2006.

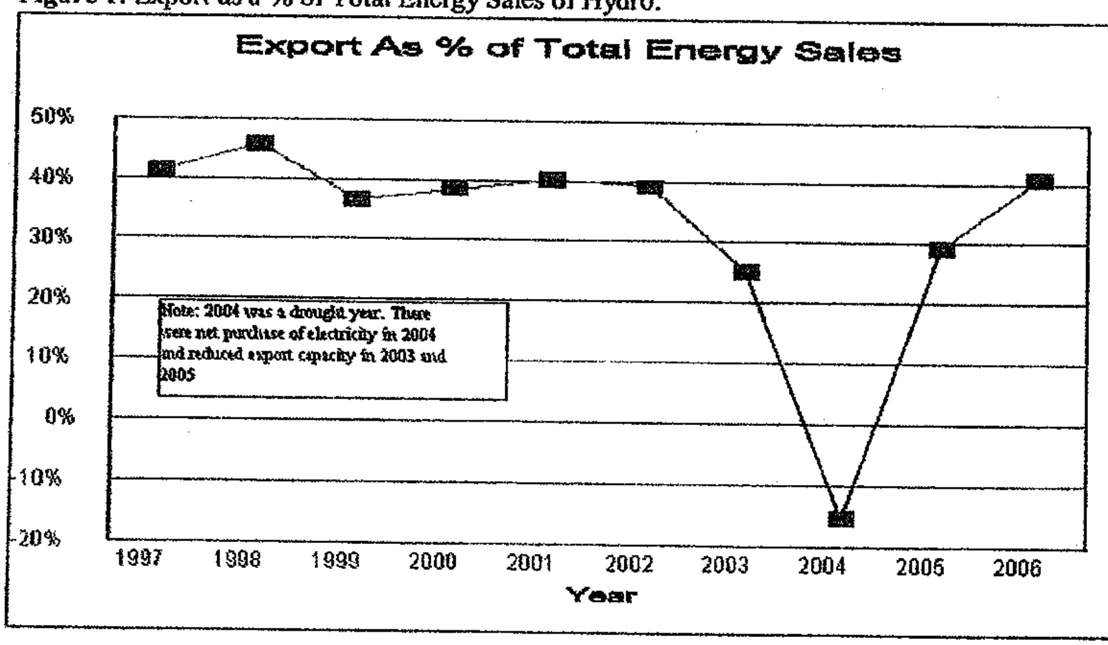
Table 1:Energy Export In Manitoba Hydro From 1997 to 2006 in GWh

Year	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
Total Energy Sold in GWh	27454	29348	25800	25726	27945	27869	25331	16745	27994	33682
Net Metered Export in GWh.	11330	13399	9469	9906	11247	10911	6378	-2578	8213	13706
Export as a % of Total Energy sold	41%	46%	37%	39%	40%	39%	25%	-15%	29%	41%

Source: Annual Report 2006

In non drought years Hydro has been exporting around 40% of its total energy sold. This can be seen from **Figure 1**.

Figure 1: Export as a % of Total Energy Sales of Hydro.



Manitoba Hydro, like any other organization, faces risks in its operations and exporting power has risks and opportunities associated with it. This report seeks to identify the risks faced by Hydro due to export, provide suggestions as to how these should be measured and recommend an organizational monitoring mechanism that should be used to effectively manage these risks.

Terms of Reference

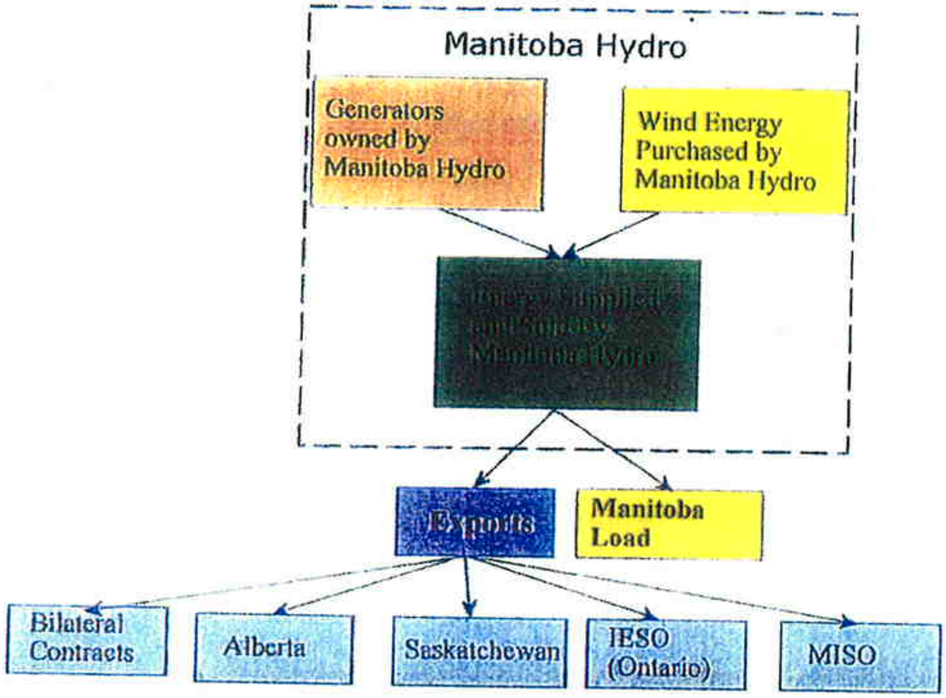
The terms of reference for this assignment are as below:

1. The identification and documentation of all risks associated with the export of electricity through the Power Sales and Operations Division.
2. The provision of recommendations regarding the appropriate measures to monitor, quantify and report on identified risks.
3. The provision of recommendations regarding the appropriate organization and staffing of the independent Middle Office.

Modeling The Core Business of Manitoba Hydro

The core business function of Manitoba Hydro can be modeled as in **Figure 2.** Manitoba Hydro generates power and sells it to its domestic and export customers and into four export markets. Most of the power generation is hydro-electric with a smaller role for Gas and Coal fired generation. As an environmentally progressive organization, Hydro is committed to buy all the wind energy generated by a private firm. The role of wind energy is insignificant in the supply mix.

Figure 2:Core Business Functions for Manitoba Hydro



The first priority of Hydro, by virtue of its mandate, is to supply the Manitoba Load. Hydro has to meet the electricity demand from Manitoba. Since Hydro generation is more than the Manitoba demand, the surplus is exported.

When exporting , Hydro has a choice of selling its power either bilaterally or in four other markets. Bilateral contracts are negotiated with counter parties and these contracts specify the quantity of power, price and when the power is to be delivered.

Markets available to Hydro to sell power are:

- **MISO**, the Midwest ISO is an independent, nonprofit organization that supports the constant availability of electricity in 15 U.S. states and the province of Manitoba. This responsibility is carried out by ensuring the reliable operations of nearly 94,000 miles of interconnected high voltage power lines that support the transmission of more than 100,000 MW of energy.
- **IESO**, manages Ontario's electricity system and operates the wholesale electricity market. It forecasts the demand for electricity and ensures that there are available supplies to meet that demand.
- **Saskatchewan**, the province does not have a power market, sales are made to SaskPower on a contractual basis.
- AESO, Alberta Electric System Operator is responsible the economic planning and operation of the Alberta Interconnected Electric System. The AESO provides open and non-discriminatory access to Alberta's interconnected power grid for generation and distribution companies. The AESO ensure system reliability and manages settlement of the hourly wholesale market and transmission system services.

Of these markets MISO constitutes the largest market for Manitoba Hydro followed by IESO. Saskatchewan and Alberta are much smaller markets as far as Manitoba Hydro is concerned but do present possible opportunities in the future and should they grow significantly would reduce the relative importance of the MISO market. The characteristics of these markets are shown in **Figure 3** and the relative percentage of Hydro's export trading activity in these different markets are shown in **Table 2.**

Figure 3: Characteristics of Markets

- Limit order market means that you can specify the price below which you will not sell or above which you will not buy.
- Forward market means that you can finalize the transaction details like price and quantity in advance of execution. In the context of power markets these are day-ahead markets.
- Spot markets are markets where the transaction is executed as soon as the transaction details are finalized. In the context of power markets, spot markets are real time markets.

Table 2:Structure of Power Export for Manitoba Hydro.

Year	Type of Trade	Market				
		Bilateral Contracts	Alberta	Sask.	IESO (Ontario)	MISO
2006 - 2007	Long Term	37%	-	-	-	-
	Short Term	35%	-	-	-	-
	Day-Ahead	6%	-	-	-	13%
	Real Time	1%	1%	-	3%	4%
	Total	**79%**	**1%**	**-**	**3%**	**17%**
2005 - 2006	Long Term	30%	-	-	-	-
	Short Term	19%	-	-	-	-
	Day-Ahead	10%	-	-	-	25%
	Real Time	-	1%	-	13%	2%
	Total	**59%**	**1%**	**-**	**13%**	**27%**

These percentages are based on dollar values. Long term means greater than two years. Short term means from two weeks to two years.

Test For Identifying Risks of Exporting Power

Having identified the role of exports in the core business of Manitoba Hydro, we are now in a position to understand the risks associated with the export of power. However, at this point we need to reiterate that we are considering only those risks that Hydro assumes because of the export activity. The appropriate test to identify these risks is to ask ourselves whether a particular risk will remain if we do not do the export activity. In case a risk remains even if we decide to abandon export activity, then such a risk is not related to exports. As for example, it is well known that the operations of Hydro is critically dependent on water availability. This risk depends on whether a drought will occur or not and is not dependent on exports. As such it is not a risk related to exports.

Risks In Power Exports

We are now in a position to identify the risks associated with exports. **First**, the export market itself may be shut out due to legislative action. This gives rise to the **Market Access Risk. Second**, when we export power under bilateral agreements, there is a chance that the counter party could default. This is the **Credit Risk. Third**, the power exports are typically done in US$. This exposes Hydro to **Foreign Exchange Risk. Fourth**, Hydro sales in the export market are done on the basis of generation and load forecasts. These forecasts are generated using some underlying model. It could happen that due to fundamental change in economic dynamics, the forecasting model will cease to be accurate. Hydro will then be exposed to **Forecasting Risk. Fifth**, Hydro could be selling power long term and thereby could conceivably be in a situation where they have committed themselves to a position beyond the generating capability. Hydro is thus exposed to the **Over-Commitment risk**. We therefore see that Hydro is exposed to the following five risks due to its export activity[1]:

* Market Access Risk
* Credit Risk
* Foreign Exchange Risk
* Forecasting Risk
* Over-commitment Risk.

Measuring Export Risk

We now need to examine the question of risk measurement and risk management. Clearly some risks are not measurable-e.g. Market Access Risk. The best that can be done here is to be aware of the political developments in the US and do scenario planning. For Credit Risk, two types of measurements are possible. One is to look at the credit ratings of counter parties and specify credit limits for each credit ratings. The second is to monitor outstanding dues and stop further sales if outstanding remain unpaid for a certain time. For Foreign Exchange Risk, measurements like VaR are possible. But for an organization like Hydro, export earnings are naturally hedged by debt servicing requirements in US dollar. I would therefore recommend that there

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[1] There is of course the risk associated with any organization that there could be a human failure or a system failure. It is not unique for power exports and hence not mentioned in this report exclusively. These risks are normally managed through formally established policy, procedure and guidelines and the best way to ensure adherence to guidelines, policy and procedure is through an extensive compliance review program.

is no need for measuring foreign exchange risk separately for power exports. Rather, Foreign Exchange Risk Management should be done at an aggregate corporate level. Forecasting Risk can be measured in several standard ways. The most common method is to compute the Mean Squared Error or MSE. Another way is to use a regression approach. I have put the technical details in the **Appendix A.** For managing risk of Over-Commitment, it is advisable to put a policy cap on the amount of power that could be committed long term. It is also advisable to put a limit by which the power sold in the day-ahead market could exceed the forecast.

Middle Office

Risk management and measurement are ongoing processes that should be preformed by or watched over by a middle office function. Sound corporate governance requires that the personnel measuring and performing the risk management function be outside the control of the organizational unit they are charged to oversee, in this case, outside the control of the Power Sales and Operations Division.

They should be reporting to the Accounting and Financing side of the organization as this side is traditionally entrusted with the responsibility of overall organizational control. There should be two persons in this middle office. One entrusted with measuring and monitoring credit risk and over-commitment risk and the other entrusted with measuring and monitoring the forecasting risk. The assessment of market access risk should be done at a higher level in the organization as it involves assessing the political situation. The person entrusted with measuring forecasting risk should have an undergraduate major in either Mathematics or Statistics and should preferably pass a course in forecasting. The person entrusted with monitoring credit risk and over-commitment risk should have an undergraduate degree and preferably a commerce undergraduate degree or some accounting/finance professional designation.

The middle office will act as a control and advisory function and be responsible for:

- Ensuring that all potential risk exposures for export power operations are identified.
- Assessing the appropriateness and accuracy of risk exposure / measurement information.
    - Ensuring that appropriate quantitative methodologies and systems are in place to measure risk exposures.
    - Testing methodologies and systems to ensure accuracy and adherence to stated objectives and logic.
    - Ensuring that measurement information is accurately calculated, prepared in a timely manner and clearly communicated.
    - Performing stress and back testing and when appropriate scenario analysis

on risk exposures.

- Ensuring that appropriate risk treatment has been established.
  - Reviewing all formal policy, procedure and guideline documents to identify gaps or weaknesses and provide recommendations to improve risk mitigation.
  - Ensuring that appropriate risk tolerances are established, they provide direction and operations are within the established limits.
- Monitoring activities to ensure adherence to established policy, procedure and guideline and assess the effectiveness of controls.
  - Reviewing activities on an ongoing basis and where possible incorporating exception reporting into those systems used for tracking and reporting of trading activities.
  - Reporting on weaknesses and all non compliance issues.
- Reviewing all new products to identify the risks around these new products and reporting the results of the review.

The risks due to exports, their measurement and the responsibility for monitoring are summarized in Table 3.

Hedging or Trading

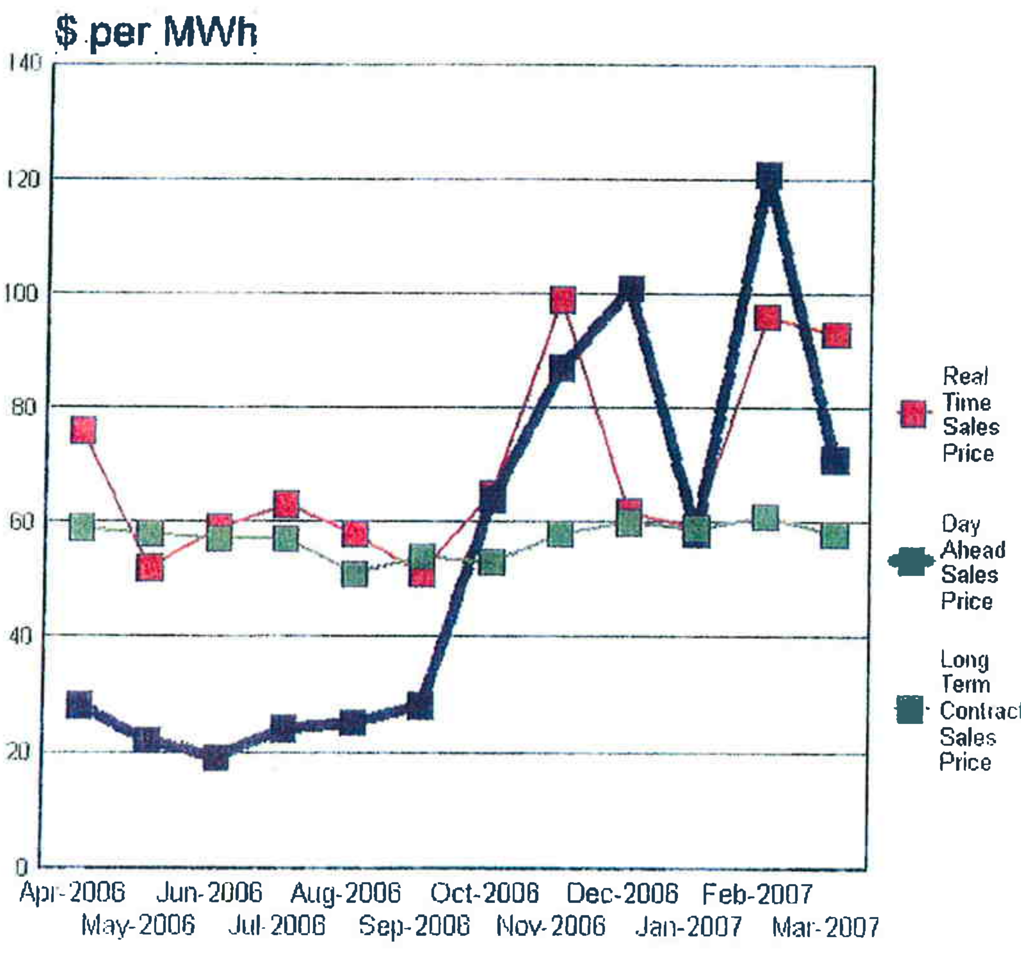
Currently, Hydro also does virtual trading, trading in Financial Transmission Rights (FTR) and trading for supplying power to Ontario by buying it from MISO. I was told that virtual trading and trading in FTRs are done for hedging the risk. I think these activities do not hedge any risk. Rather they are arbitrage activities meant to profit form an assessment of superior capacity on the part of Hydro to spot mispricing. The supply of power to Ontario by purchasing it in MISO is pure trading in power. It is up to the Hydro management to decide if they want to continue doing these arbitrage and trading activities. My point is that these activities have nothing to do with hedging risks of power exports. I have explored these issues in **Appendix B** in greater detail.

If Hydro decides to continue with these trading activities then it is best done by a wholly owned subsidiary. For Hydro, power export should be viewed as a way of selling surplus power after meeting Manitoba Demand. Long term sales commitment should be minimal because nobody can predict the water availability in the long term. Instead Hydro should take advantage of MISO and sell its forecast surplus in the Day-Ahead market. Real time market should be used to iron out any temporary excess or shortfall in trade execution. It can also be seen from **Figure 4** that in the second half of 2006-2007, both day-ahead and real time prices have been higher than the prices obtained in the long term contract.

Table 3:Summary of Risks for Power Exports

Number	Type of Risk	Description	Measurement	Responsibility
1.	Market Access Risk	Risk that access to US market may be cut off.	It's a binary event. Periodically political developments be analyzed and implications assessed.	Higher Management
2.	Credit Risk	Risk of selling to bad credit counter parties or default by counter parties	Credit Monitoring, Credit Limits, Receivable Outstanding.	Middle office personnel in charge of credit risk monitoring.
3.	Foreign Exchange Risk	Risk of unfavorable movement in US$ which is the currency of trading.	Measurements are possible, but this risk is best managed in an aggregate manner for the whole organization	Treasury
4.	Forecasting Risk	Risk of erroneous forecasts or forecasting model being outdated.	Mean Squared Error; Regression Approach	Middle office personnel in charge of monitoring forecasting risks.
5.	Over-Commitment Risk	Risk of selling power beyond the generating ability.	Monitoring of commitment vis a vis forecast	Policy on Cap by Higher Management. Monitoring by middle office.

Figure 4: Average Power Prices in 2006-2007.



Other Issues

It appears that a number of forecasting methods and systems are in use. It is advisable that Hydro selects and implements a single forecasting system for decision making. There should be an audit trail established for this forecasting system.

It also appears that there is no single method to model and optimize the operations of Manitoba Hydro. Therefore decisions on power generation and power purchase may not always be taken in a co-ordinated manner. Therefore, I would recommend that Hydro takes step to implement an optimization program and operational decisions should be linked to the output of this optimization program. Such a program can be run dynamically and optimal output/selling decisions may be communicated to the implementing units.

Summary of Findings and Recommendations

1. Risks associated with energy exports are:

    a. Market Access Risk

    b. Credit Risk

    c. Foreign Exchange Risk

    d. Forecasting Risk

    e. Over-commitment Risk.

2. Apart from selling surplus power to export markets Manitoba Hydro is also engaged in merchant transactions which are power trading activities. Should the Corporation increase the amount of these activities it may become advantageous to create a wholly owned subsidiary to manage them. In creating a wholly owned subsidiary a clearer risk management process can be developed and pure merchant transactions could be pursued. Separation also ensures that core corporate activities, such as the selling of surplus power, are not exposed to possible taxation laws.

3. When Manitoba Hydro chooses to sell power under long term commitments it obtains a firm price for a specific quantity of power but it also exposes the Corporation to additional risk of selling beyond its capabilities of dependable energy when water flows/reservoir conditions are in or near drought conditions

or future domestic load increases are above projections. With the creation of regional energy markets and the ability to transact available surplus power in real time and day ahead markets the need to have such long term commitments in place is not as important. In the future it may become advantageous to continue to reduce these types of long term sales as a percentage of the corporation's total export sales.

4. Manitoba Hydro uses several different forecasting demand and supply models to determine its energy position. These multiple systems can create problems as there is a greater possibility of error and because they might use different assumptions and methods which conceivably could result in suboptimal decisions. The Corporation should continue to automate the input processes of these models as much as possible and in the future consider a company wide optimization system for these operational decisions.

5. The middle office should be set up under the control of the Accounting and Finance Branch. Two persons are required in the Middle Office-one a commerce graduate and the other a graduate in a quantitative discipline like Mathematics or Statistics with some course credits in Forecasting.

Appendix A

Method For Measuring Forecasting Risk

Suppose y_t is the forecast value of some measured attribute and x_t is the actual realized value of the same attribute.

Then Mean Square Error (MSE) = $\frac{1}{n}\sum_{t}(y_t - x_t)^2$ where n is the sample size.

Suppose we write[2]

$$e_t = y_t - x_t$$
$$\delta_t = (y_t - \bar{y}) + (x_t - \bar{x})$$

Regress e_t (dependent variable) on δ_t (Independent Variable).

The intercept, if significant, will give an estimate of the bias and the coefficient of δ_t, if significant will give an estimate of the error due to difference in variance of the forecast series and the actual series.

[2] I wish to acknowledge my intellectual debt and my thanks to my co-author Dr. Larry Bauer of Memorial University for suggesting this approach for measuring forecasting risk.

Appendix B

Analysis of Hedging Activity

Hydro undertakes virtual trading and buys FTR. There were three arguments advanced as a rationale for entering into theses activities. These arguments are:

★ These activities hedge risk due to export marketing.

★ These activities make money for Hydro by buying energy low and selling it high.

★ Buying FTRs is necessary to protect Hydro from higher congestion charges while buying power. Hydro needs to buy power because prior long term commitments have resulted in Hydro being short on generating capacity and Hydro needs to make up this shortfall by purchasing power in MISO.

Let us examine these rationales.

On Virtual Trades and FTRs as Instruments for Hedging Risk.

Virtual trading means taking a trading position without lining up the corresponding closing transaction. Thus when one sells electricity virtually one is selling electricity without having the corresponding generation lined up. Similarly, when one does a virtual purchase of electricity, one does not have a corresponding load for that electricity. Virtual transaction will have to be reversed and I fail to see how virtual transactions could be used to hedge risks. Rather virtual transactions open the party to the risk that prices might move unfavorably and at the time of closing the party might lose money.

Financial Transmission Rights (FTR) are used to hedge price risks arising out of line congestion. The important thing about FTRs is that these instruments are to be used by loads to hedge the price risk due to higher congestion. The generator does not need to use FTR. Manitoba Hydro is in the business of generating electricity. It is not a net load or at any rate it is not supposed to be a net load. Hence, FTRs are not meant to be instruments for Hydro. In view of the preceding arguments, I am skeptical about the claim that virtual trading and purchase of FTRs hedge risk due to export marketing.

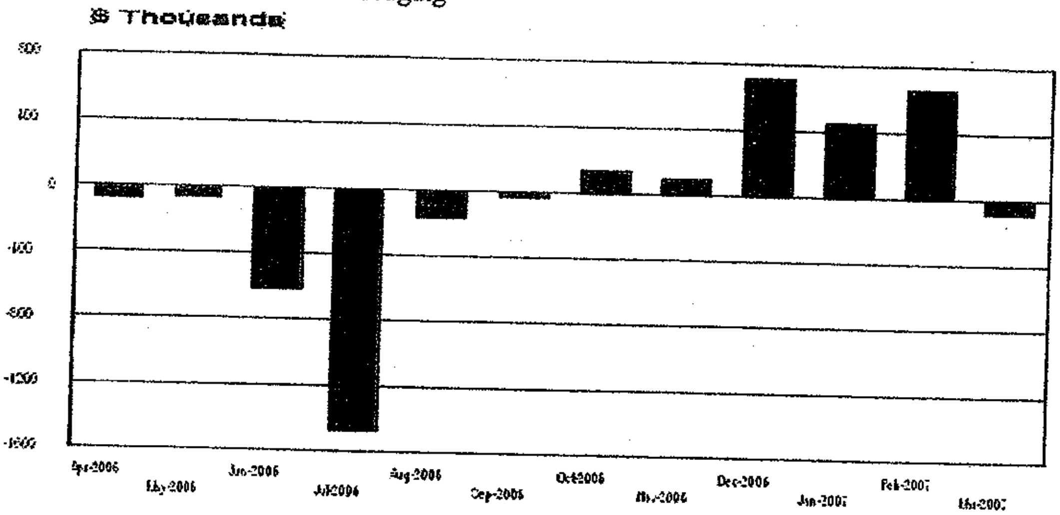
On Virtual Trading and FTRs As Money Making Activities For Hydro.

Table 4 shows the net revenue from hedging in 2006-2007. **Figure 5** shows the same data graphically.

Table 4: Net Revenue from Hedging in 2006-2007

	Apr-2006	May-2006	Jun-2006	Jul-2006	Aug-2006	Sep-2006	Oct-2006	Nov-2006	Dec-2006	Jan-2007	Feb-2007	Mar-2007	For the Year 2006 - 2007
Net Revenue From Hedging $ Thousands	(74)	(60)	(616)	(1,472)	(164)	(29)	138	100	713	448	659	(86)	(443)

Figure 5: Net Revenue From Hedging



It is clear that in 2006-2007 hedging has not been a profitable activity for Hydro. Generating money from trading activity requires an ability to buy low and sell high. **Figure 6** gives the ratio of average monthly purchase price to the average monthly selling price for 2006-2007. In order to be profitable the graph should be below the 100% line (because under the 100% line purchase price is less than the selling price).

Figure 6:Average Purchase Price As Percentage Of Average Selling Price

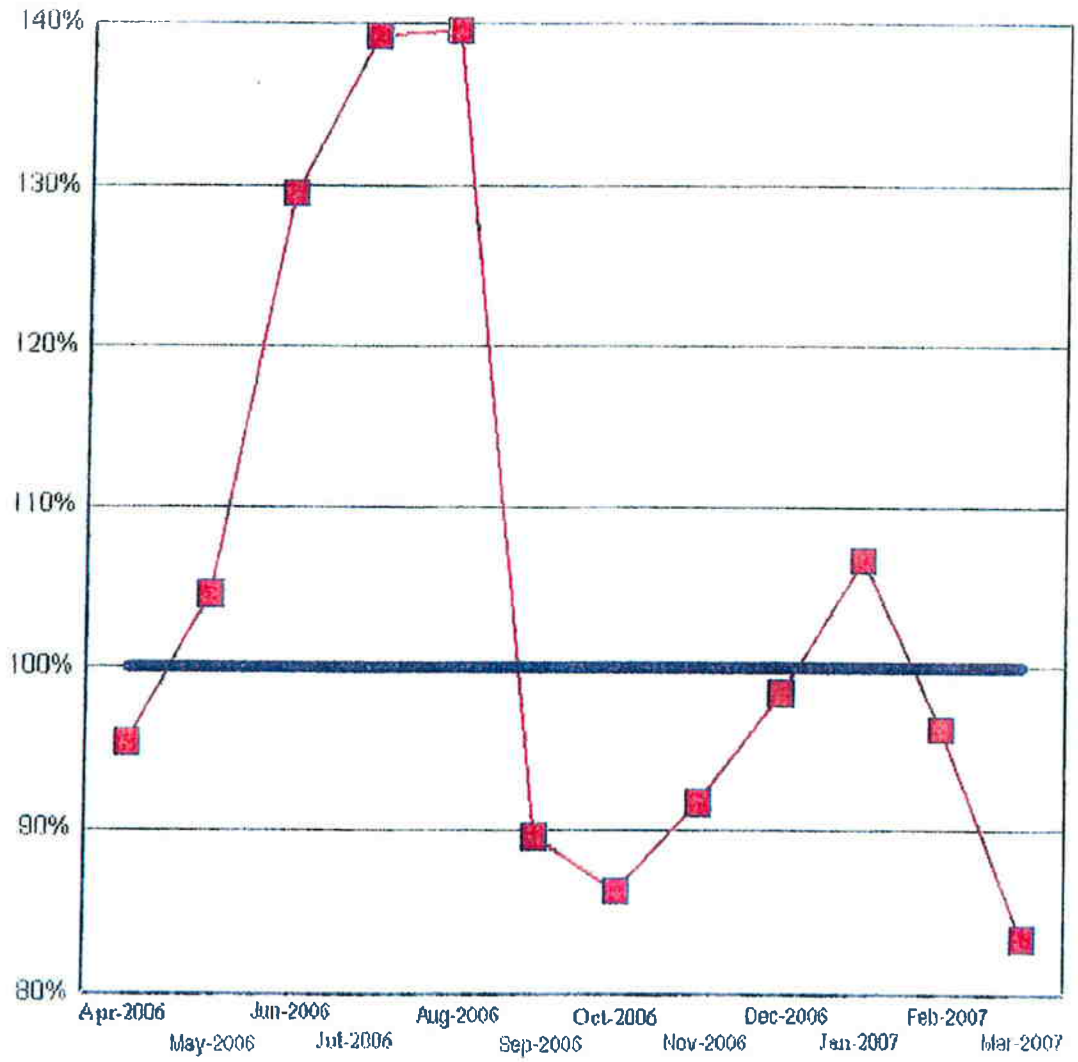
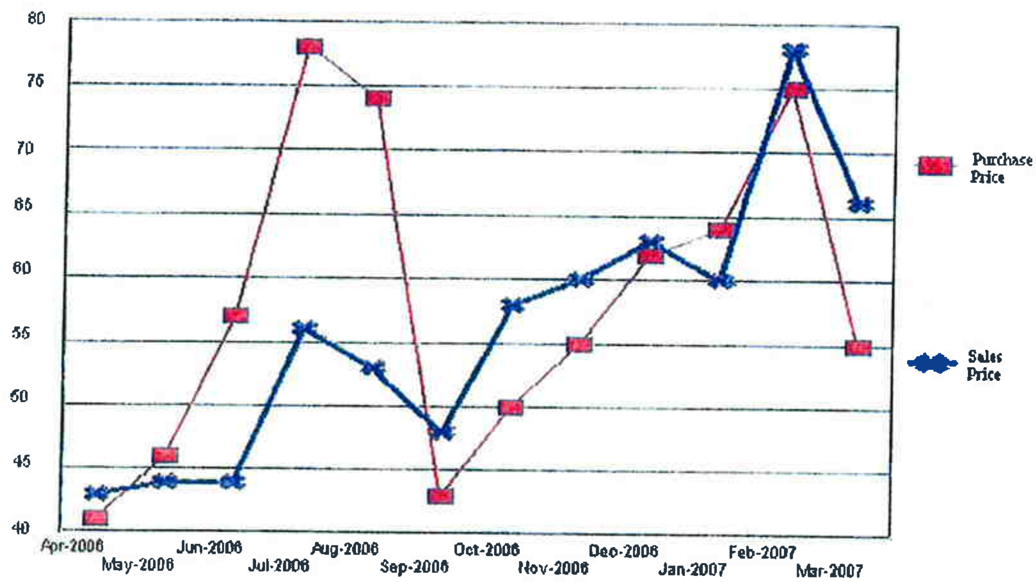


Figure 7 shows the average monthly purchase price and the average monthly

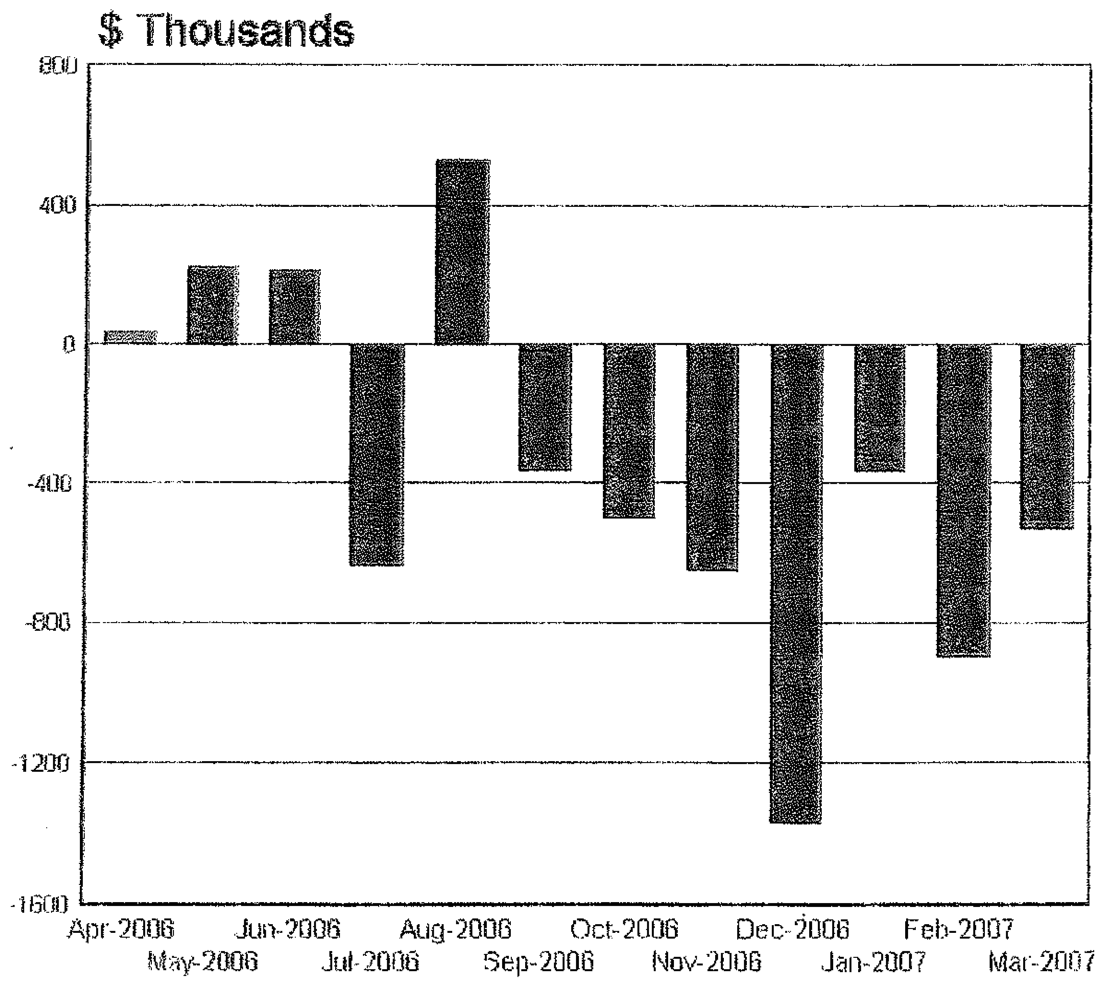
selling price for 2006-2007.

Figure 7: Average Sales and Purchases Prices in 2006-2007



Based on this evidence I conclude that at least in 2006-2007, the trading activity (i.e. purchasing power to sell it) has not been a consistently profitable activity. This conclusion is further bolstered when we look at the net revenue from trading in power for Ontario. Hydro supplies power to Ontario through the 200 MW transmission line between Manitoba and Ontario. In addition, Hydro purchases power from MISO and supplies it to Ontario. This later transaction is a purely trading activity. The MWhs purchased from MISO and the MWhs supplied to Ontario are closely matched. However, when we look at the revenue from this trading activity(shown in **Figure 8**) we find that this is mostly a loss making activity.

Figure 8: Net Revenue From Trading To Supply Ontario (also known as System Hedging Product)



<u>On FTRs Being Necessitated By Long Term Power Sales Commitment</u>

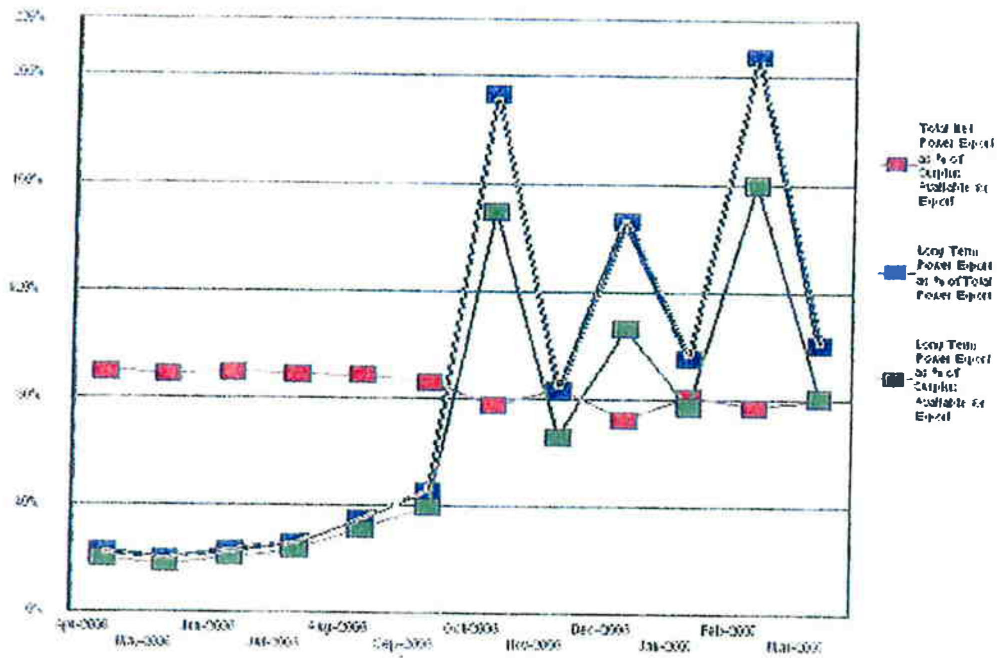
Table 5 gives the monthly data on long term power sales with respect to the available surplus for the year 2006-2007.

Table 5: Long Term Sales in Relation to Total Power Exports and Power Surplus. Except for percentage numbers all other numbers are in GWh.

	Apr-2006	May-2006	Jun-2006	Jul-2006	Aug-2006	Sep-2006	Oct-2006	Nov-2006	Dec-2006	Jan-2007	Feb-2007	Mar-2007
Total Generation	2865	3247	3158	3284	3101	2364	2052	2087	2510	2777	2430	2459
Net Manitoba Firm Load	1706	1689	1674	1816	1736	1603	1857	2076	2287	2441	2285	2141
Surplus Available for Export	1159	1558	1484	1468	1365	761	195	11	223	336	145	318
Total Power Export Net of Purchases	1040	1385	1328	1305	1210	658	151	-28	162	273	112	255
Total Net Power Export as % of Surplus Available for Export	90%	89%	89%	89%	89%	86%	77%	-255%	73%	81%	77%	80%
Long Term Power Export as % of Total Power Export	22%	20%	23%	26%	35%	46%	193%	-968%	146%	95%	207%	101%
Long Term Power Export as % of Surplus Available for Export	20%	18%	21%	23%	31%	40%	150%	2465%	106%	77%	160%	81%

Figure 9 represents the data in the last three rows of **Table 5** graphically with the numbers for November 2006 replaced with the averages for other months. As can be seen from **Figure 9**,there seems to be a fundamental qualitative change in the export from October 2006 onwards. From October 2006, it is true that Long Term Sales have increased greatly compared to the surplus available. While this situation needs to be corrected, I would suggest that in the longer term this needs to be managed by bringing down the amount of long term sales.

Figure 9: Relationship of Long Term Sales with Total Power Export and Surplus available. November figures are averages for other months. All other numbers are actuals.



53

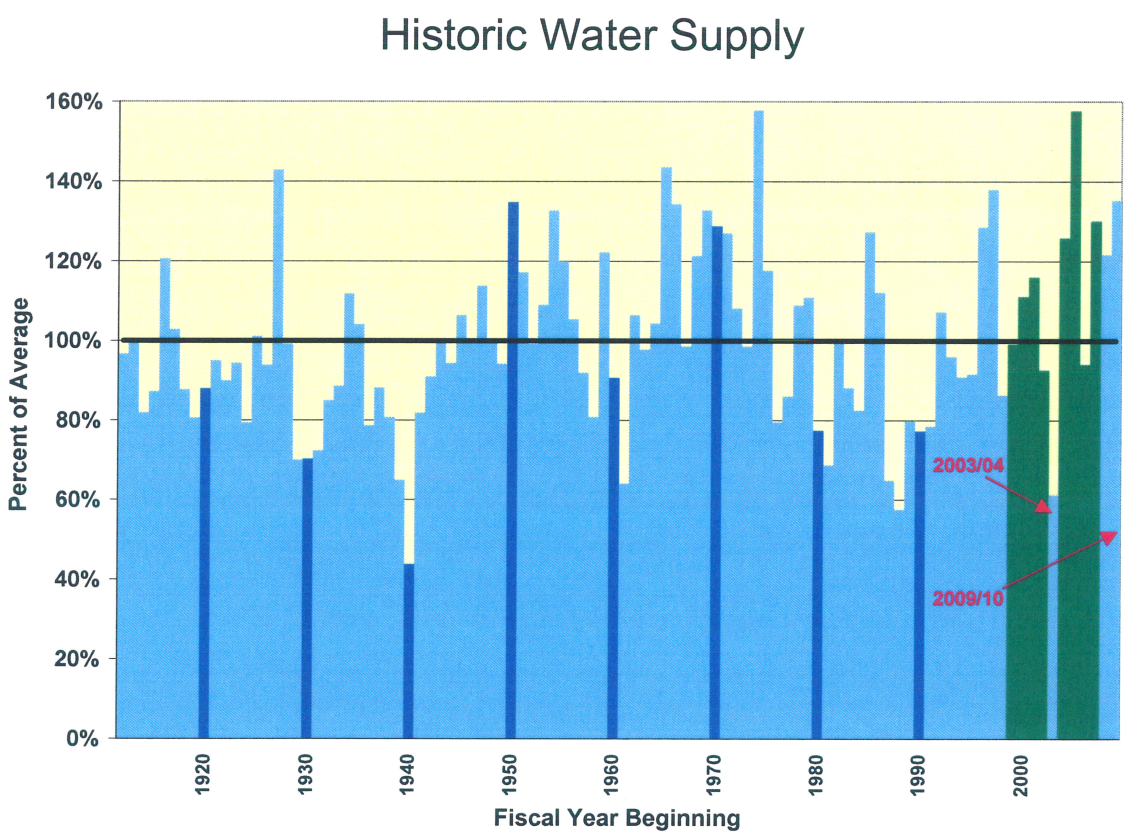
PUB/MH I-155

Subject: **Tab 12: Corporate Risk Management**
Reference: **ICF Report, (Page 57), Exhibit 4-2**

a) **Please confirm that the 1999-2007 period (minus 2003/04) reflects a relatively high flow period and does not represent a normal/average situation.**

ANSWER:

In five out of 8 years between the 1999/00 to 2007/08 (excluding 2003/04) Manitoba Hydro experienced above average inflow conditions. The period in question is shaded green in the figure below.



54

ARTICLE 5
ENERGY EXCHANGE

Section 5.01 During a period of Adverse Water Conditions, UPA shall deliver energy to MH upon MH's request. Such energy shall be that energy which is available to UPA after UPA has made provision to comply with any applicable governmental emission standards, and to supply its firm energy commitments, now or hereafter created, including firm sales to other utilities. The maximum amount of energy which UPA is obligated to deliver under this section, in any twelve (12) month period, is the lesser of that required to enable MH to meet its firm commitments or 660 GWh.

Section 5.02 MH shall pay UPA for energy delivered under the provisions of Section 5.01, an amount equal to UPA's Incremental Cost plus ten (10) percent multiplied by the amount of energy delivered. The Incremental Cost for such energy will be determined after providing for firm and nonfirm sales which UPA is making at the time when such energy is delivered.

Section 5.03 If MH receives energy in accordance with Section 5.01, MH shall offer to return to UPA an amount or amounts of energy totalling that received from UPA, within five years of the delivery of such energy. The price for energy returned to UPA shall be the weighted average price paid by MH for the energy received from UPA in the preceding five years under Section 5.01, after adjusting the price MH paid in each Contract Year by a factor equivalent to the ratio of:

(a) The factor $E_{T(n)}$, from Section 4.02 (a), for the Contract Year in which the energy is returned to UPA divided by;

(b) The factor $E_{T(n)}$, from Section 4.02 (a), for the Contract Year in which the energy was delivered by UPA to MH.

55

MH Appendix 12.2

CONTAINS BUSINESS SENSITIVE AND HIGHLY CONFIDENTIAL MATERIAL

FOR INTERNAL MANITOBA HYDRO USE ONLY

Independent Review of Manitoba Hydro Export Power Sales and Associated Risks

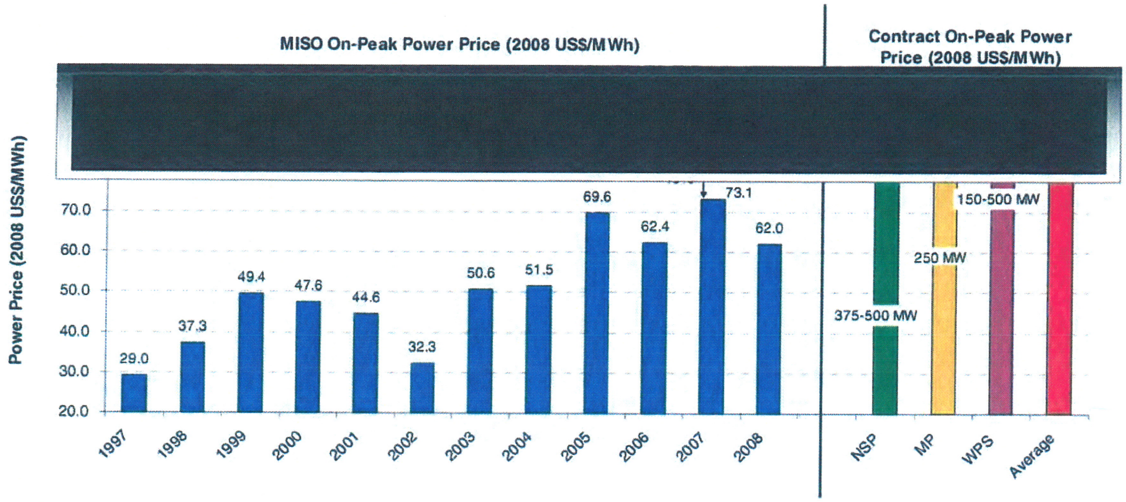
September 11, 2009

Submitted to:

Manitoba Hydro

Submitted by:
ICF International
9300 Lee Highway
Fairfax, VA 22031 USA
Tel: 1.703.934.3000
Fax: 1.703.934.3968

EXHIBIT 1-6
Comparison of Contract Prices with Historical MISO On-peak Spot Power Prices



Source: 1997-2000 MAPP Weekly Index; 2001-2005 Northern MAPP Weekly Index; 2005-2009 YTD MINN HUB Weekly Index from Power Market Week
Note: Contracted energy price with MP is the average of a fixed price and MHEB nodal price; [redacted] reflects only the fixed component of the contracted price

- **Proposed Contract Prices versus Existing Contract Prices** – Manitoba Hydro's proposed export contract prices are well above average existing contract prices, i.e., more than [redacted] percent higher.

- **Domestic Generation Service Prices** – Manitoba Hydro's proposed export contract prices are well above domestic rates for generation services, i.e., nearly [redacted] times as high. The proposed average export contract price is well above the domestic generation cost of approximately $27/MWh[5] by [redacted] percent.

- **ICF Wholesale Price Forecasts Available at Time of Contract Negotiations** – Our review of contract versus forecast pricing started with ICF forecasts which are provided regularly to MH. This is in part because ICF did not have access to the other forecasts provided to MH due to the confidentiality provisions regarding the forecasts (except two averages discussed further below). Manitoba Hydro's proposed contract prices are above ICF's forecasted prices available at the time contract negotiations were ongoing. [redacted] (see Exhibit 6-12); MH long-term prices are even higher when compared to the average forecasts from all forecasters. It is our understanding that the NSP contract was based on 2006 projections, and the MP and WSP contracts were based on the 2007 projections. Thus, Manitoba Hydro appears to have properly accounted for the then current price forecasts in their negotiations. We believe

[5] This is subsidized domestic generation component of price, based on calculations in Recommended Method under Cost of Service Study, March 2006. Note, the calculations assume subsidy of 20 percent from export sales.

EXHIBIT 3-2
Manitoba Hydro: Exports and Imports (GWh), 2000-2007

Year	Export			Import	Net	
	Firm	Non Firm	Total	Total	Export-Import	Firm Share of Net Exports (%)
2000	6,829	6,503	13,332	2,089	11,243	61%
2001	7,130	5,915	13,045	1,048	11,997	59%
2002	6,677	2,876	9,553	2,585	6,968	96%
2003	7,320	820	8,140	6,442	1,698	431%
2004	7,146	3,151	10,298	2,821	7,477	96%
2005	5,704	9,737	15,442	310	15,132	38%
2006	4,819	9,724	14,543	1,131	13,412	36%
2007	4,770	8,105	12,875	708	12,167	39%
Average 2000-2007	**6,299**	**5,854**	**12,154**	**2,142**	**10,012**	**63%**

Source: 2000-2007 Annual Electric Power Generation, Transmission and Distribution Reports, Statistics Canada; data on supply and disposition of electric energy
Notes:
(1) All firm generation exported to other provinces or other contracting parties is represented under the firm export category
(2) Non-firm category includes secondary exports and exchange exports
(3) Imported generation includes imports under all categories, i.e., imports from other provinces, short-term imports and long-term imports

3.2.1 Current Manitoba Hydro Contracts

Manitoba Hydro is currently involved in eight long-term export trade agreements with six electric utilities and numerous short-term agreements with a variety of electric utilities and marketers in mid-western U.S., Ontario, and Saskatchewan. Three of the long-term agreements involve seasonal diversity exchanges of energy ranging from 150 MW to 200 MW with two U.S. utilities. Seasonal diversity exchanges are a particularly valuable form of agreement, especially between summer peaking U.S. utilities and winter-peaking Canadian utilities.

By entering into these agreements, Manitoba Hydro attempts to reduce the revenue uncertainty associated with these export sales, and since export revenues constitute a large share of Manitoba Hydro's revenues, they serve as one of the most important risk management control mechanisms of the company. In order to assure that these long-term agreements do not expose Manitoba Hydro to undue risks, the Corporation prescribes a number of rules and processes that guide its contract formation process. These issues are discussed further in later chapters.

The pricing structure of the contracts is designed to provide capacity and energy payments. Manitoba Hydro's existing contracts provide average capacity payment of US$[redacted]/kW-yr and average on-peak energy payment of approximately US$[redacted]/MWh in 2008$.[35] On a levelized

[35] Source: Summary of LT Contracts.doc (received from Manitoba Hydro)
Note: The average contract energy price represents energy weighted average of fixed component of individual contract prices. Annual escalation of 2.5 percent is assumed.

per MWh basis, on-peak firm power price is US$56/MWh. The potential contracts are more profitable with an average US$[redacted]/MWh on-peak energy price and US$[redacted]/kW-yr as capacity price[36]. On a per MWh basis, this results in on-peak firm price of US$[redacted]/MWh or [redacted] percent higher than prices under existing contracts. Prices are discussed at length in Chapter 6.

The existing export contracts supply guaranteed energy to the buyers and have the option to curtail the energy in several cases such as adverse hydro condition, damage to transmission link etc. Potential contracts also have terms and conditions that include curtailment provisions under adverse hydro conditions and specify the curtailment priority. This is discussed further in Chapter 7.

3.2.2 Proposed Manitoba Hydro Contracts

Manitoba Hydro has executed binding term sheets with three U.S. utilities, NSP, WPS, and MP. Based on these contracts, the Corporation expects to increase its commitment in 2018 to approximately 2,400 GWh annually with a commitment to WPS and further increase that commitment in 2020 to over 6,000 GWh annually with a contract signed with Minnesota Power. Details on the export sales volumes are discussed in chapters 7 and 10.

Most of the existing contracts expire by 2014 (see Exhibit 3-3). Thus, the proposed new contracts restore and then grow long-term contract sales in the 2015-2025 period. These contracts are discussed further in later chapters.

[36] Source: Summary of LT contract.doc

EXHIBIT 6-1
Summary of Potential Contracts (Including Diversity Exchange)

Contract	Contracted Capacity (MW)	Energy Delivery Type	Negotiated On-Peak Firm Price (US$/MWh)	Price Index	Duration
NSP	375 – 500	Guaranteed On-Peak Energy and additional Weekend Energy	[redacted]	[redacted]	2015 to 2025
NSP-Diversity Exchange	350	Summer/Winter Diversity Exchange Energy	[redacted]	[redacted]	2015 to 2025
MP	250	Guaranteed On-Peak Energy, additional Weekend Energy	[redacted]	[redacted]	2020 to 2035
WPS	150 – 500	Guaranteed On-Peak Energy and additional Weekend Energy	[redacted]	[redacted]	2018 to 2032
Total/ Average	**1,125 - 1,600**		[redacted]		

Sources: Summary of LT contract.doc and individual terms sheets of NSP, MP and WPS
Notes:
1. MP contract includes 250 MW System Power Participation Sale for the 2020 through 2035 period and a total of 3.3 million MWh non-firm energy sales for the 2008 through 2022 period. The realized on-peak price ($/MWh) to Manitoba from MP System Participation Sale will be comprised of levelized capacity payment and average of fixed energy price and Minnesota Hub index price applicable to peak hour energy delivery. The on-peak price of [redacted]/MWh represents only the fixed component.
2. Average on-peak price is weighted by generation.
3. Details of the contract terms are shown in Chapter 7

6.3.2 Existing Contracts

Manitoba currently sells 1,470 MW under long-term contracts. Counterparties are in MISO including MP and NSP, two buyers of the proposed new contracts, and several smaller primarily public power entities including GRE, Otter, MMPA, and SMMPA. Only WPS is a new long-term buyer under the proposed contracts. Most of the existing contracts end by 2015[54], when the NSP contract is proposed to start. Note, the MP and WPS proposed contracts start later and are associated with the acceleration of the construction of the Conawapa and Keeyask hydro facilities.

Manitoba Hydro's existing long-term contracts were in effect as early as 1995 (see Exhibit 6-2) when power prices were significantly lower than prices witnessed in spot markets in the recent years and were primarily determined by base load capacity or to a limited extent by natural gas fired power plants as the price setting marginal unit. The average capacity price the Corporation obtains from these contracts is [redacted] and average energy payment is

[54] The NSP diversity exchange contract ends in 2016 but has been extended to continue to 2019 in winters.

approximately [redacted] resulting in on-peak firm power price of US$56/MWh (all prices in 2008 US$).[55] The pricing terms of the existing contracts are summarized in Exhibit 6-3.

EXHIBIT 6-2
Manitoba Hydro's Existing Contracts (Including Diversity Exchange)

Buyer	Capacity (MW)	Start Date	End Date
MP	50	05/01/09	04/30/15
NSP	500	05/01/05	04/30/15
NSP (Diversity Exchange)	150	05/01/95	04/30/15
NSP (Diversity Exchange)	200	11/01/96	10/31/16
Otter	50	05/01/00	04/30/15
GRE (Diversity Exchange)	150	05/01/95	04/30/15
MMPA	60	05/01/00	04/30/09
MMPA	30	05/01/09	04/30/12
SMMPA	30	04/01/08	03/31/13
MP (Non-Firm Energy)	250	05/01/08	04/30/22
Total	1,470	NA	NA

Source: Summary of LT Contract.doc (received from Manitoba Hydro)

EXHIBIT 6-3
Existing Contract Price Summary for System Participation Contracts

Contract Name (Existing Buyer)	Contract (MW)	Capacity Price (2008 US$/KW-yr)	On-Peak Energy Price (2008 US$/MWh)	Average On-Peak Firm Price (2008 US$/MWh)
MP	50	[redacted]	[redacted]	[redacted]
NSP	500	[redacted]	[redacted]	[redacted]
Otter	50	[redacted]	[redacted]	[redacted]
MMPA	60/30	[redacted]	[redacted]	[redacted]
SMMPA	30	[redacted]	[redacted]	[redacted]
MP-NFE	250	[redacted]	[redacted]	[redacted]
Average		[redacted]	[redacted]	55.7

Source: Summary of LT Contract.doc (received from Manitoba Hydro)
Notes:
1. Annual escalation of 2.5 percent is assumed
2. Average price represents generation (MWh) weighted average price of individual contract prices
3. Actual capacity factor of each contract is used to levelize the capacity payment
4. The above summary excludes sales categorized under 'Diversity Exchange Agreement'

6.4 ADEQUACY OF PRICES NEGOTIATED UNDER LONG-TERM CONTRACTS

6.4.1 Comparison of Prices of Existing and Potential Contracts

A comparison between the existing and potential contracts shows marked increase in prices likely to be obtained by the Corporation from the proposed future long-term power sales (see

[55] Source: Summary of LT Contracts.doc (received from Manitoba Hydro)
Note: The average contract energy price represents energy weighted average of fixed component of individual contract prices. Annual escalation of 2.5 percent is assumed.

Exhibit 6-4). The proposed contract price is [redacted] percent higher in real terms than the existing average contact price. This is a favorable fact in favor of our overall conclusion that the proposed pricing is adequate.

While the average capacity component of potential contracts is [redacted] than that of the existing contracts, the average energy component of potential contracts is almost [redacted] than that of the existing contracts. The increase in energy prices in the potential contracts reflects a shift toward natural gas fired plant as the price setting marginal unit and the expectation of tighter environmental regulations. As noted, this pricing also increases Manitoba Hydro's incentive to deliver electricity.

EXHIBIT 6-4
Existing and Potential Contract Price Summary for System Participation Contracts

Contract	Capacity (MW)	Capacity Price (2008 US$/kW-yr)	On-peak Energy Price (2008 US$/MWh)	Average Price (2008 US$/MWh)
Existing				
MP	50	[redacted]	[redacted]	[redacted]
NSP	500	[redacted]	[redacted]	[redacted]
Otter	50	[redacted]	[redacted]	[redacted]
MMPA	60/30	[redacted]	[redacted]	[redacted]
SMMPA	30	[redacted]	[redacted]	[redacted]
MP-NFE	250	[redacted]	[redacted]	[redacted]
Average		[redacted]	[redacted]	**55.7**
Potential				
NSP	375-500	[redacted]	[redacted]	[redacted]
MP	250	[redacted]	[redacted]	[redacted]
WPS	150-500	[redacted]	[redacted]	[redacted]
Average		[redacted]	[redacted]	[redacted]

Source: Summary of LT Contract.doc (Received from Manitoba Hydro)
Notes:
1. Annual inflation of 2.5 percent has been assumed
2. Average price represents generation (MWh) weighted average price of individual contract prices
3. Actual capacity factor of each contract is used to levelize the capacity payment
4. The above summary excludes sales categorized under 'Diversity Exchange Agreement'
5. For contracts, such as Potential MP (250 MW) contract, wherein energy price is represented [redacted], only fixed price has been considered.

6.4.2 Export Contract Prices Versus Domestic Generation Prices

Manitoba Hydro exports its surplus energy to the MISO market both under contracted long-term sales as well as short-term opportunity sales. Over the last nine years, on average, it has exported 30 percent of its energy to MISO and has derived approximately 37 percent of its revenue from these export sales. The generation component of domestic Manitoba Hydro rates is approximately $27/MWh[56] Canadian versus existing contract prices of $[redacted]/MWh U.S., and proposed prices of [redacted] U.S. This is a favorable finding supporting the adequacy of price.

[56] Manitoba Hydro Prospective Cost of Service Study (for year ended March 31, 2006)

56

TRADE SECRET & CONFIDENTIAL

Northern States Power - Manitoba Hydro

500 MW System Participation Power Sale Agreement

This SYSTEM PARTICIPATION POWER SALE AGREEMENT ("Agreement") is entered into effective as of August 1 2002, by and between Northern States Power Company ("NSP" or "Buyer"), a Minnesota corporation in the United States and The Manitoba Hydro-Electric Board ("MH" or "Seller"), a Manitoba Crown Corporation incorporated pursuant to the provisions of *The Manitoba Hydro Act* (R.S.M. 1987, c.H190), each of the foregoing entities being sometimes referred to individually as "Party" or collectively referred to as "Parties".

RECITALS

0.01 WHEREAS, the Parties entered into a 500 kV Coordination Agreement (the "Coordination Agreement") effective February 1, 1991 for the interconnected operation of the Parties' 500 kV transmission line and for the provision of various services pursuant to the Service Schedules of said Coordination Agreement; and

0.02 WHEREAS, Section 4.01(b) of the Coordination Agreement provides for other transactions to be executed by the Parties from time to time; and

0.03 WHEREAS, NSP issued a Request for Proposals dated August 2, 1999 in response to which MH submitted an offer to sell System Participation Power which was accepted by NSP; and

0.04 WHEREAS, MH is capable of providing System Participation Power to NSP as provided hereunder from its existing resources, including those under construction; and

0.05 WHEREAS, NSP desires to purchase and MH desires to sell System Participation Power pursuant to the terms and conditions set forth in this Agreement; and

0.06 WHEREAS MH recognizes that NSP is relying on the reliable and consistent availability of System Participation Power in accordance with the terms and conditions of this Agreement; and

0.07 WHEREAS, NSP and MH are each party to the Restated MAPP Agreement; and

0.08 WHEREAS, the Parties require governmental permits and approvals for the import and export of electric energy.

NOW, THEREFORE, in consideration of the mutual promises and covenants of each Party to the other contained in this Agreement and other good and valuable consideration, the receipt and sufficiency of which is hereby acknowledged, the Parties covenant and agree as follows:

NSP's Transmission Provider's system) upon expiration of the firm transmission service rights granted by the 500 MW Power Sale Agreement between the Parties dated June 14, 1984. To the extent NSP is unable to obtain such firm transmission service under the applicable OATT NSP shall retain any rights it may have to utilize any such right of first refusal.

Section 3.02 NSP shall be responsible for Scheduling the Energy for delivery by MH to the Point of Delivery.

Section 3.03

a. The Point of Delivery shall be at the Point of Interconnection unless agreed otherwise by the Parties.

b. MH may provide Scheduled Energy to a Point of Delivery within NSP's transmission system other than the Point of Interconnection, provided (i) NSP agrees in its sole discretion that such delivery will not result in any adverse economic or reliability impact on NSP in light of all circumstances (including the effect such request has on NSP's Energy Schedule under this Agreement), and (ii) MH shall agree to pay all transmission service costs, including congestion management fees, associated with delivery of Guaranteed Energy to a Point of Delivery other than the Point of Interconnection. NSP shall respond to a request for a Point of Delivery other than the Point of Interconnection within a reasonable period of time.

Section 3.04 As between the Parties, title to and risk of loss of the Energy shall pass from MH to NSP at the Point of Delivery.

Section 3.05 Unless otherwise mutually agreed, all Scheduling of the Energy to the Point of Delivery shall occur by 9:00 AM CPT on the Business Day prior to delivery. The maximum Schedule for Energy during any hour shall be 500 MW. With the exception of Schedules that are curtailed pursuant to the terms of this Agreement, all Schedules associated with Guaranteed Energy shall provide for continuous 16 consecutive-hour delivery at 500 MW per hour, unless otherwise mutually agreed. During periods of curtailment, Schedules for delivery of Guaranteed Energy for durations less than 16 hours and at rates of less than 500 MW per hour are permitted to the extent required by the factor(s) giving rise to the curtailment. Subject to the requirements of this Section, Sections 2.03, 3.06 and 3.07, NSP in its sole discretion shall determine the hours of Guaranteed Energy delivery.

Section 3.06

a. MH shall not have the right to withhold, reduce or curtail the amount of Accreditable Capacity made available to NSP through this Agreement for any reason, including Force Majeure, except to the extent allowed pursuant to Section 7.02 hereof.

b. MH's curtailment of Energy shall be allowed only in the circumstances and to the extent set forth below in paragraphs (1), (2), (3) and (4):

(1) In the event that, in order to maintain the reliable operation of the interconnected AC transmission system, MH is required to reduce or curtail NSP's

Schedule, the transaction curtailment priority used by MH relative to all uses of such AC transmission system at the time shall be implemented exclusively under MH's Transmission Provider's OATT, excepting that (i) MH shall redispatch its generation system to the full extent possible to alleviate such event or condition without curtailing deliveries under this Agreement and (ii) curtailment of NSP's Schedule hereunder shall be allowed to the extent and for the period that absent such curtailment, outage to End-Use Load in Canada or Border Accommodation Power Sales (up to the limits imposed pursuant to Section 3.08(1)) would have been required, consistent with Good Utility Practice.

(2) In the event MH or its Transmission Provider ceases to have an OATT, curtailment or reduction of NSP's Schedule hereunder in order to maintain the reliable operation of the interconnected AC transmission system, shall be implemented exclusively in accordance with this clause (2). Curtailment of energy deliveries under this paragraph to accommodate such events shall be implemented as follows, in the order specified, until the required amount of loading relief has been obtained: a) MH shall first curtail all transmission service or transactions, that are lower than the highest priority delivery service available as allowed by Section 3.01(a) above, which contribute to the condition requiring curtailment; b) MH shall redispatch its generation system to continue the Energy Schedule hereunder consistent with producing the desired loading mitigation upon the congested facility(s); c) to the extent all transactions identified in clause (a) of this paragraph are curtailed and system redispatch is not sufficient to produce the necessary mitigation that would avoid curtailment of the NSP's Schedule, the transaction curtailment priority used by MH relative to all uses of such AC transmission system at the time shall be implemented in a comparable and non-discriminatory manner, provided that (i) MH shall redispatch its generation system to the full extent possible to alleviate such event or condition without curtailing deliveries under this Agreement and (ii) curtailment of NSP's Schedule hereunder shall be limited to the extent and for the period that absent such curtailment, outage to End-Use Load in Canada or Border Accommodation Power Sales (up to the limits imposed pursuant to Section 3.08(1)) would have been required, consistent with Good Utility Practice.

(3) In the event that all or a portion of MH's generation capacity is unavailable due to (i) forced outages of generating unit(s), (ii) derates of generating unit(s) caused by low water flow or other reason, (iii) the unavailability of generation outlet capacity caused by a forced outage or derate of MH's high voltage DC ("HVDC") system, or (iv) scheduled

(8) any reimbursement to NSP for extra transmission costs incurred pursuant to Section 3.03(b).

Section 6.03 MH is responsible for all costs as a result of making Accreditable Capacity available pursuant to this Agreement, as well as any transmission service charges, including replacement of or payment for Real Power Losses and other expenses incurred in order to deliver Energy to the Point of Delivery. NSP shall be responsible for any costs including transmission service charges and replacement of or payment for Real Power Losses and other charges associated with the Accreditable Capacity and Energy, or its receipt, of and from the Point of Delivery.

Section 6.04 In the event that (1) the Parties do not agree to Point of Delivery other than the Point of Interconnection; and (2) MH's Transmission Provider adopts an OATT (or subsequent transmission service as allowed by this Agreement), that does not permit MH to reserve transmission service solely within Canada for the delivery of Energy to NSP at the Point of Delivery; and (3) MH is required to modify the transmission service arranged for the purposes of this Agreement, then: MH shall be responsible for reserving alternate transmission service for Delivery of the Energy to NSP. In that circumstance, the Parties shall cooperate in good faith to allocate such transmission costs equitably to conform with the cost allocation provided in Section 6.03 (ie. based on costs incurred north versus south of the Point of Interconnection). If the Parties cannot reasonably agree on such allocation, the matter shall be resolved pursuant to Section 10.09.

Section 6.05

TRADE SECRET – CONFIDENTIAL

(3) Notwithstanding the foregoing, nothing in this Section 6.05 shall preclude or limit NSP's right to designate the resources purchased under this Agreement as "renewable resources" or to apply any portion of this purchase to applicable portfolio standards or other regulatory requirements related to renewable resources, provided that such designation or application by NSP shall not obligate MH to manage the supply of Energy purchased pursuant to this Agreement in any particular manner, nor restrict MH from the particular type of generating resources used to supply the Energy purchased pursuant to this Agreement (including energy obtained from third party purchases, regardless of the generation type used by the third party), nor shall anything in this Section 6.05 constitute a representation by MH that the Energy supplied by MH pursuant to this Agreement is supplied from renewable resources.

ARTICLE 7

CONDITIONS OF SALE AND PURCHASE

Section 7.01

(1) This Agreement shall be conditional upon the Parties receiving by July 31, 2003, and maintaining in effect the listed approvals:

UPA DIVERSITY EXCHANGE AGREEMENT

between

THE MANITOBA HYDRO - ELECTRIC BOARD

and

UNITED POWER ASSOCIATION

FEBRUARY 1, 1991

ARTICLE 5
ENERGY EXCHANGE

Section 5.01 During a period of Adverse Water Conditions, UPA shall deliver energy to MH upon MH's request. Such energy shall be that energy which is available to UPA after UPA has made provision to comply with any applicable governmental emission standards, and to supply its firm energy commitments, now or hereafter created, including firm sales to other utilities. The maximum amount of energy which UPA is obligated to deliver under this section, in any twelve (12) month period, is the lesser of that required to enable MH to meet its firm commitments or 660 GWh.

Section 5.02 MH shall pay UPA for energy delivered under the provisions of Section 5.01, an amount equal to UPA's Incremental Cost plus ten (10) percent multiplied by the amount of energy delivered. The Incremental Cost for such energy will be determined after providing for firm and nonfirm sales which UPA is making at the time when such energy is delivered.

Section 5.03 If MH receives energy in accordance with Section 5.01, MH shall offer to return to UPA an amount or amounts of energy totalling that received from UPA, within five years of the delivery of such energy. The price for energy returned to UPA shall be the weighted average price paid by MH for the energy received from UPA in the preceding five years under Section 5.01, after adjusting the price MH paid in each Contract Year by a factor equivalent to the ratio of:

(a) The factor $E_{T(n)}$, from Section 4.02 (a), for the Contract Year in which the energy is returned to UPA divided by;

(b) The factor $E_{T(n)}$, from Section 4.02 (a), for the Contract Year in which the energy was delivered by UPA to MH.

57

Manitoba Hydro Risks: An Independent Review

Submitted to

The Public Utility Board of Manitoba

Submitted By

Dr. Atif Kubursi
and
Dr. Lonnie Magee

November 15, 2010

the forecasts is not of mere academic interest: the viability and reliability of the system depends upon them.

We have obtained from MH data on the discrepancies between annual forecast values and annual actual values for generation, total revenues, total costs, net revenues and exports between 1999 and 2009.

Positive errors (under-predicting) are not equivalent to negative errors (over-predicting). This fact is also contingent on the nature of the variable predicted. For example, under-predicting revenue is not a problem but under-predicting costs are a major problem. This is why different forecasting error measures have been devised to deal with this issue. We will here restrict our presentation to the simple variance of the predicted from the actual values. We will not use the average of the error variance because it is meaningless when positive and negative values are averaged (negative and positive errors cancel each other). A better measure would be one that takes the average of the absolute values of the errors, which in the case of the numbers in Table 3.1 would be an average of 3.3% instead of the 0% reported by MH.

On average the HERMES model predicts annual generation well. It over-predicts almost equally to what it under-predicts. Where it failed, however, was in the crucial period of a critical year of low flow. The error in 2003/04 is large, with over 11% (see Table 3.1 and Figure3.5).

Table 3.1 – Forecast and Actual Generation, 1999-2009

FISCAL YEAR	TOTAL GENERATION			
END MAR 31	FORECASTED	ACTUAL	Variance	% Variance
1999/00	29,347	30,146	799	3%
2000/01	32,265	32,687	422	1%
2001/02	33,419	32,557	-862	-3%
2002/03	29,924	29,118	-806	-3%
2003/04	21,820	19,369	-2451	-11%
2004/05	30,918	31,534	616	2%
2005/06	36,516	37,629	1113	3%
2006/07	33,515	32,121	-1394	-4%
2007/08	34,330	35,354	1024	3%
2008/09	34,547	34,528	-19	0%
Average	31,660	31,504	-156	0%

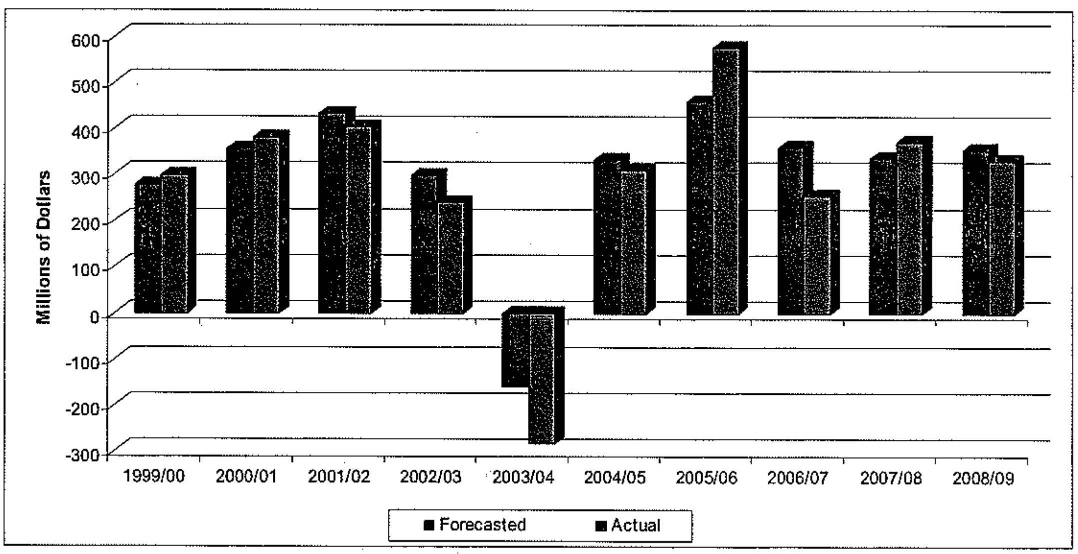
Source: Manitoba Hydro. HERMES.

Table 3.4 – Forecast and Actual Net Revenue, 1999-2009

FISCAL YEAR	NET REVENUE			
END MAR 31	FORECASTED	ACTUAL	Variance	% Variance
1999/00	278	298	20	7%
2000/01	356	381	26	7%
2001/02	433	404	-29	-7%
2002/03	298	239	-59	-20%
2003/04	-158	-282	-124	-79%
2004/05	333	309	-24	-7%
2005/06	460	577	117	25%
2006/07	358	253	-105	-29%
2007/08	335	371	35	10%
2008/09	354	329	-26	-7%
Average	305	288	-17	-6%

Source: Manitoba Hydro.

Figure 3.8 – Forecast and Actual Net Revenue, 1999-2009



Source: Manitoba Hydro.

Another perspective on HERMES predictive accuracy is presented in Table 3.5 and Figure 3.9. It is clear that the second forecast is far better (lower prediction errors) than the first forecast. The accuracy of HERMES rises with time and the incorporation of more recent information improves the forecasts. It seems that when in the year the forecasts are made is crucial. Forecasts made in July are far better than those made earlier. By July the water conditions after spring rain are more reliable. Errors of the first

3.2.4 Summary and Recommendations

By any standard HERMES is an impressive system: it developed over time and grew in complexity and utility. Its developers are on staff and the source code is home stored. We are satisfied that the technical staff that support and run the model are competent and committed. We have seen a couple of demonstrations of the system and we have seen its objective function, constraints and inner workings. It is a large system with over 8000 constraints and bounds and a larger number of variables. It is capable of generating a rich set of bases (linearly independent vectors) that define feasible solutions for the objective function to choose from among them the optimal one.

We noticed, however, that a forced solution is made by assigning huge costs to particular objective function coefficients. This is a standard practice in large LP systems but still worrisome. There is always the fear that users will select optimum solutions close to actual operations or desired solutions.

Being an internally developed and maintained system, HERMES has advantages and disadvantages. Among the advantages is the ease and flexibility of changing and upgrading the system. We understand that this is a continuous process at MH. But being a home grown product it may not be documented sufficiently or regularly. We have not seen a User Manual or a Technical Manual--typical products of commercially developed systems. Home grown products are protected and defended with zeal by their developers. This is why it makes sense to subject the system to an external audit by the Committee of Experts (MAC) we mentioned in the context of MOST. The need for this validation and audit is doubly important when the model is home grown.

The deterministic nature of the model calls for more thorough adjustment and upgrades. It makes sense to move to a stochastic system or at least to add a few stochastic modules. The same goes for some non-linear modules in the system. Since the underlying structure is nonlinear and new solvers (GAMS or AIMMS) can easily solve large nonlinear and stochastic systems, it is worth considering these upgrades. Successive optimization may reduce this need, but in our opinion this will be a poor substitute.

The availability of PRISM and its gut @RISK at MH should facilitate using stochastic forecasts instead of the arbitrary optimistic and pessimistic variants.

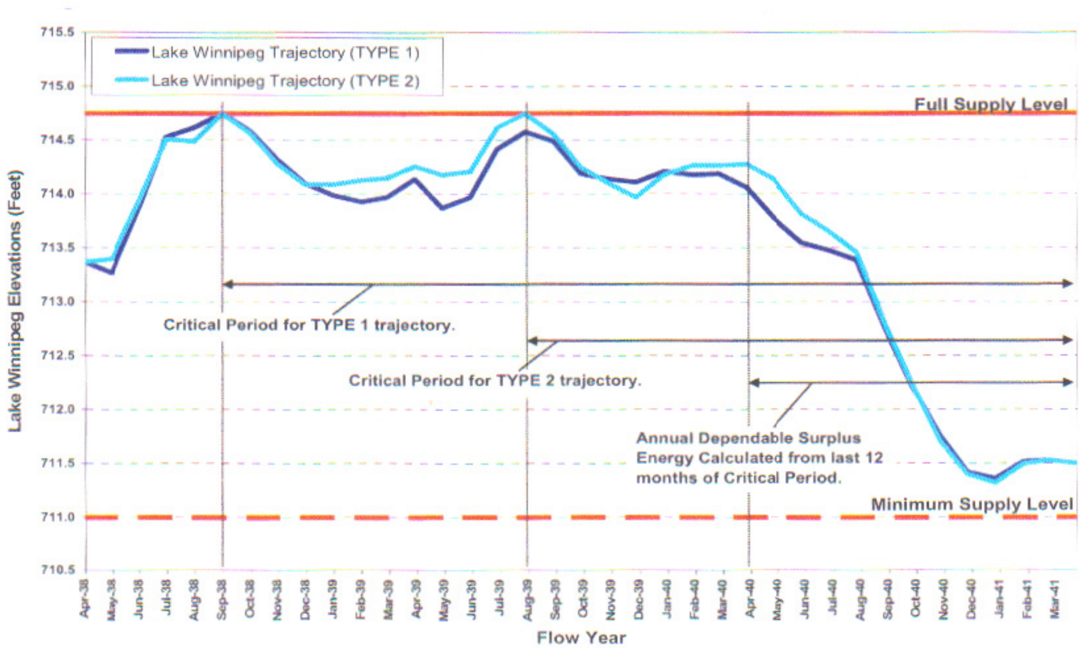
HERMES is one of many systems within the general class of LP system. It is for a medium term horizon. It sits between MOST and SPLASH. We would like to urge the model builders and users to fine tune their models' integration and collectively work on synchronization and communication. It would make sense to insure that the same data inputs are shared among all of the models. Using different data inputs or different coefficients raises red flags and detracts un-necessarily from the usefulness of the system.

We would like to single out for praise HERMES' incorporation of temperature (HDD and CDD) variables. This is a crucial advantage given the sensitivity of load to this variable and the extent to which it is expected to vary in the future. But we implore MH to consider moving more into stochastic and dynamic contexts. There are associated costs with the development of these capacities both in terms of human resources, software and hardware. There will be many added complexities to finding an initial solution and other time sensitive problems, but the benefits may and can outweigh the costs.

The use of antecedent forecasts and relying on regression equations to use the past and/or the present to predict the future values of flows is justifiable; care however, should be exercised to explore multiple lags, different estimating equations and the inclusion of meteorological variables that many hydro utilities use in the US and elsewhere (New York Power Authority (NYPA)). The heavy reliance on a single lag is these antecedent forecasts needs some reconsideration. Indeed the t-statistics on some of these regressions used by MH are reasonably high month to month, the R^2 are not on the whole particularly high but the real issue is that with missing variables in the regression equations the single variable may be picking the influences of the missing variables and the standard regression diagnostic measures need to be interpreted with caution.

A serious alternative to antecedent forecasts, even those that include multiple lags and other meteorological data, is the use of full-blown hydrological models with full accounting of precipitation, evaporation and flows. Manitoba Hydro's excessive dependence on water and its unique sensitivity to different water flows are strong arguments for a serious consideration of building or sourcing out this capacity. There are some unique hydrological and regulatory features that make these models particularly difficult for MH such as the multiple watersheds, out of province control of water flows to Manitoba, and the shallow and porous waterbeds. But the expected benefits from such models and systems cannot be exaggerated.

Figure 3.17 – Lake Winnipeg Critical Period Trajectory

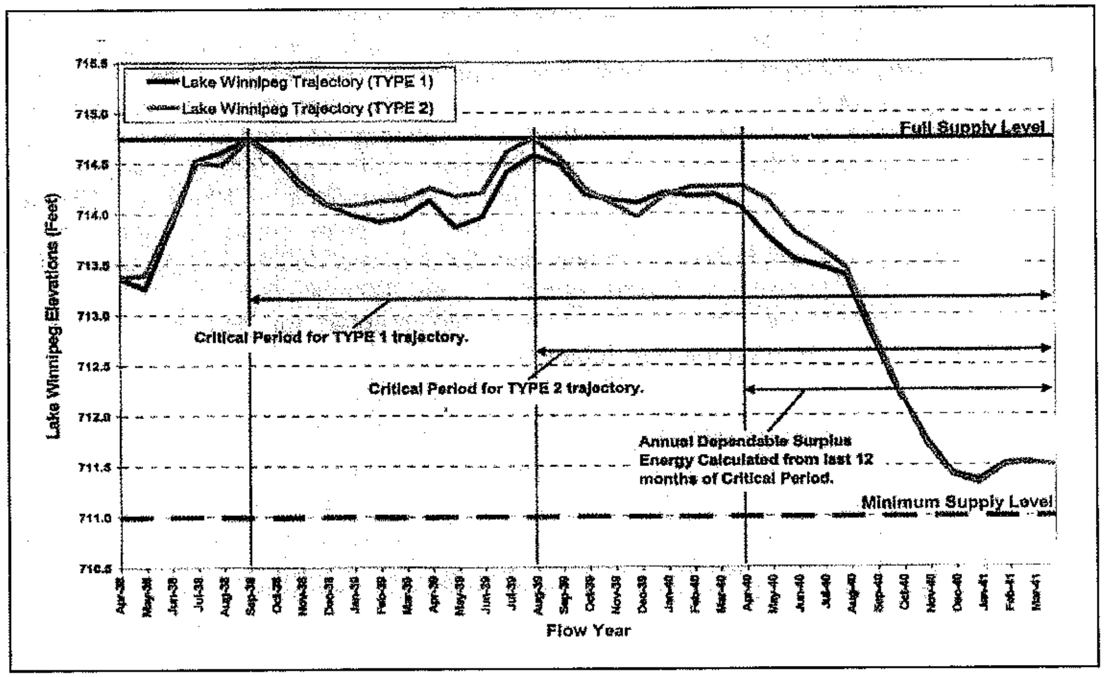


Source: Manitoba Hydro. An Introduction to the SPLASH Model. August 31, 2009.

3.2.5.3 The Rule Curve Simulation

The rule curve simulation is designed to ensure that the system works under operation rules and guidelines that will result in an adequate supply of hydro power over all water flow conditions. These guidelines include the end of month reservoir levels that will provide the required storage in the system reservoirs and will guarantee adequate generation to meet forecasted dependable energy requirements during critical flow years.

Figure 3.17 – Lake Winnipeg Critical Period Trajectory



Source: Manitoba Hydro. An Introduction to the SPLASH Model. August 31, 2009.

The input data for the rule curve run as shown in Figure 3.18 include the surplus dependable energy determined in the preceding Dependable Energy Run. The requirement for this simulation is the minimum amount of water in storage required to satisfy future energy demand and the output is the amount of water required in storage at start of water year in the critical period. The methodology here can be represented as a simulation of the critical flow period working backwards through the months of a load year. By working backwards through time, the required reservoir elevation at the beginning of a month is determined by calculating whether the controlled reservoirs should release or store water in order to meet firm energy demands for the month. This alternative generation expansion scenarios and the second is a calculation of the incremental value of energy supply relative to the case that results from adding one unit of capacity or relaxing an upper or lower bound constraint.

The flexibility of SPLASH is a noted advantage. The core structure allows for the use of different scenarios for probing the sensitivity of the optimal solution to different specification of values (coefficients of the objective function) or changes in the constraint constants.

3.2.6 Summary and Recommendations

SPLASH is a critical component of the model family at MH. It plays a crucial role in simulating future alternatives and is depended upon to plan the system requirements for expansion in the future. Given this critical role, any weakness or gap can have serious implications for decisions based upon it, or alternatively any improvement and upgrade can yield high returns.

We are happy with the simulation structure of the system and the insights this can add to its utility. The three phased process of determining dependable energy to rule curve determination of elevation levels to minimizing production costs are interesting and valuable applications.

There are a number of issues, however, that need to be addressed:

First, the system relies heavily on linear approximations to deal with a basically nonlinear underlying structure. There are grounds to question whether or not a nonlinear specification is now necessary to deal directly with this problem. Given the major advances in computer languages in the optimization field, this consideration is not far fetched.

Second, the model is fully deterministic and operates with perfect foresight. Uncertainty is recognized but not dealt with directly. There are a number of areas where the simple introduction of some elements of PRISM can be relied upon to broaden the probabilistic base of the model. This will also increase and improve on the integration of the models at MH and add value to both models. We see a number of areas where SPLASH can use

@RISK, particularly when it comes to export and import prices, water flows and reservoir elevation levels.

Third, SPLASH is and is not an extension of HERMES but the two need to be reconciled and situated on a common platform. At the moment they are not fully integrated. There is more room for linking explicitly the two systems to benefit from their commonalities. The real danger lies in the fact that they can and have produced different results. SPLASH results are more "optimistic" than those of HERMES. In some respects they impose different structures. For example, SPLAH fixes ending lake levels in its simulations to guarantee next period's firm requirements, in HERMES these are part of the optimal solution.

Fourth, SPLASH is an in-house developed system which can benefit from an audit by an external committee of experts.

Fifth, we have seen some good documentation covering the components of the system but nothing formal. Again we would like to suggest careful and formal documentation of the system in User and Technical manuals.

Sixth, the staff supporting the system are qualified but again this group should be formalized and expanded to be an identifiable group that is continuously trained and integrated in the overall model community at MH.

Seventh, we have not seen a real demonstration of the model and did not have the opportunity to get to look at the gear work of the model, its forecasts and their accuracy. This was not offered despite our interest in seeing an actual demonstration. We were readily and openly allowed to examine and see the guts of HERMES and its forecasts but not SPLASH.

Eighth, we are not convinced that the integration of the past 94 flows is a sufficient procedure for taking account of water volumetric risks unless it can be shown that this possibility is remote. There may be situations where a more severe or a longer drought could take place, besides the recourse to an average or median flow is simply dismissing the embedded deviations of the system from central tendencies. The use of statistical processes to entertain multitudes of runs is necessary; it will enrich the base of alternatives and can settle whether a lower minimum is likely and with what likelihood.

Ninth, SPLASH working within the perfect foresight framework, always uses to the utmost available water leaving no room for uncertainty. It seems from our discussion with MH that this is not the operating principle at work.

Tenth, SPLASH only permits the availability imports at 100% of their need and as such it tends to underestimate the costs and volumes of these import needs.

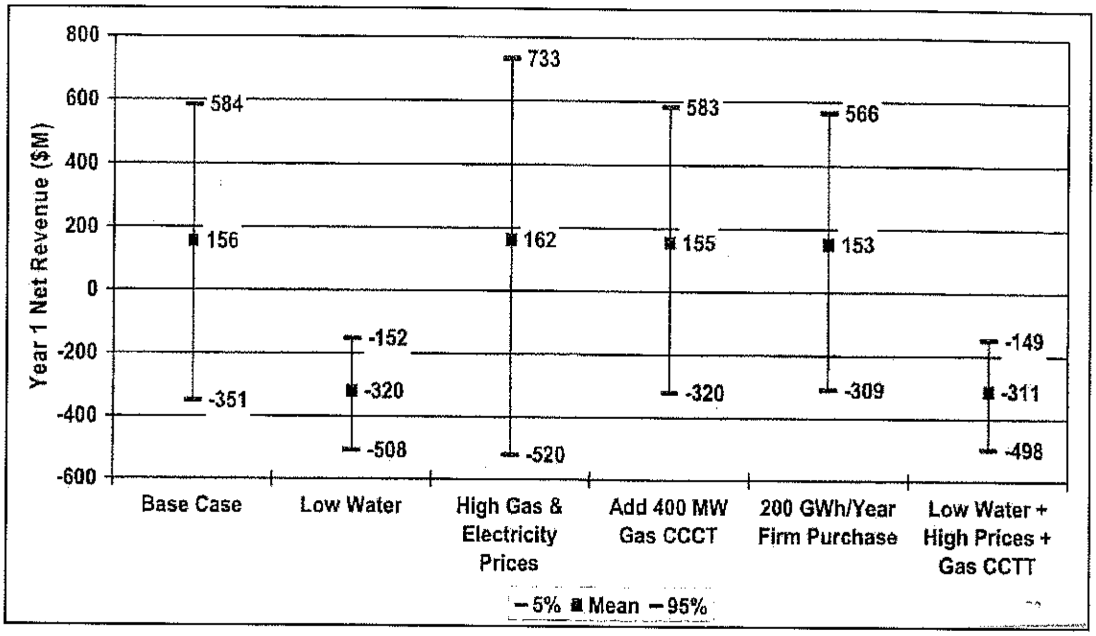
Eleventh, the cost and implications of the assumption of perfect foresight must be determined. It is generally assumed that this assumption is necessary and almost costless. When major investment decisions are informed by SPLASH and when drought costs are estimated using its results, the implications of this assumption in a world rife with uncertainty must be fully identified and measured. When water levels in reservoirs are kept at their minimum levels because we know exactly when a drought will begin and end, the actual costs of a drought would be seriously understated.

3.2.7 Power RIsk System Model (PRISM)

Traditionally, quantitative analyses combine single "point" estimates of a model's variables to predict a single result. Estimates of model variables must be used because the values which actually will occur are not known with certainty. Some estimates may be too conservative and others may be too optimistic. The combined errors in each estimate often lead to a real-life result that is significantly different from the estimated result. Decisions based on "expected" results might be wrong and could have been avoided if one had a more complete picture of all possible outcomes. @RISK is a system designed to explicitly include the uncertainty present in the estimates in order to generate results that show all possible outcomes. This system is embedded into PRISM to evaluate a wide spectrum of forecasts using different probability distributions on forecast values, and these results are complemented with Monte Carlo simulations.

The way @RISK works is to generate "simulations" which combine all the uncertainties identified in a modeling situation. Point estimates of variables are no longer one number. Instead, the full range of possible values and some measures of likelihood of occurrence for each possible value can be used. @RISK uses all of this information, along with the model, to analyze a rich menu of possible outcomes. It is designed to reflect the information that would be generated if hundreds or thousands of "what-if" scenarios were

Figure 3.21 – Summary of Risk Analysis with Confidence Levels



Source: Lindsay Melvin. Risk Analysis Using PRISM. Power Point Presentation. 2010.

3.2.8 Summary and Recommendations

PRISM fills a gap at MH. The aftermath of the 2003 drought highlighted the need for probabilistic models that can map a wide set of possibilities and introduce uncertainty into decision making and planning at MH, avoiding arbitrary specifications of pessimistic and optimistic forecasts. Besides, it enriches the set of what-if runs to a large magnitude from randomly generated values, replacing the limited number of possibilities typically used.

As an in-house system it allows staff at MH to customize the model to the specific needs of the Organization. We met the staff responsible for PRISM and we are convinced that they have the required computer and engineering skills to deal with its extensions and use. We are also convinced that the staff can be beefed up to include statisticians who are familiar and competent to make informed selections and representations of the underlying probability distributions available in @RISK. We have already alluded to the sensitivity of the results in PRISM to the choice of the underlying probability distributions. The competent choice of these distributions is of crucial importance to the usefulness and relevance of the results to risk management.

Some of the concerns we have about PRISM are in fact associated with the adoption by PRISM of results and vectors from other systems. The concern is that problems or errors in one system may be propagated through the entire family of models.

While @RISK is a standard industry tool for dealing with uncertainty, it is a coarse system that requires customization and sophisticated knowledge of statistics and other related skills to become more flexible and produce genuine and desirable fruits. There are other systems in the field and there is no substitute for detailed and painstaking analyses of the individual risks and the use of standard Value at Risk calculations (VaR).

Nonetheless, we are happy that PRISM draws on other models at MH, when appropriate and the materials drawn upon is vetted. It is generally our belief that the various and separate models that MH uses should all be integrated and should be adjusted to operate on a common platform. Indeed, there is always a concern that errors could be propagated throughout the system, but having separate and disjointed models that do not conform to a consistent set of operations is also problematic. In this regard, it would be helpful if @RISK is used in the other models too. The relationships between these models are two-way streams of interdependence in which the outputs of one system become the inputs to another.

Some of the noted and preferred uses of @RISK have coupled it with other statistical models where it comes into play after other sources of uncertainty have been identified and exploited. For example, in the context of a specific application at MH, the model parameters of the Electric Load Forecast can be represented by their distributions using the standard errors of the coefficients. It is then that @RISK could be used to model the exogenous variables' distributions. The ultimate outcomes would represent the combined influence of parameter imprecision and uncertainty about forecast values of exogenous (independent or determining) variables.

A few minor but important issues for PRISM improvement would include, first, freeing it from the seasonal and annual structure and allowing it to deal with intra-year issues. Second, a richer and a better statistical anchor could be used to model water variability than the SPLASH characterization. More than a 5 years time horizon can be adopted to highlight results. Third, as it stands now it is only an energy model; it may be worth considering augmenting it into an energy capacity model. Fourth, price volatility modeling can be enhanced. The simple inert acceptance of external forecasts may be supported by a firmer probabilistic approach. Fifth, there is a need to contrast and compare @RISK calculations with other quantitative risk calculations. Sixth, there ought to be greater integration and harmonization of the PRISM model with other MH models. Seventh, documentation of the system explicitly in User and Technical manuals must be carried out on a regular basis. Eighth, the system should be subjected to external audit and verification. Ninth a statistician/econometrician should be added to the model support team.

3.2.9 Electric Load Forecast

The electric load forecast is a central and critical component of planning operations in the medium and long term at MH. It is used in most other models and therefore its accuracy is of critical importance to all these models and their forecasts.[19]

3.2.9.1 The Residential Sector

The forecasts are prepared by market segment. The residential sector share in total electricity sales in Manitoba was 32.8% in the base year 2008/09. This market segment includes electricity sales to individually metered residential customers for non-business operations. The residential sector is comprised of four forecast groups:

- Basic
- Seasonal
- Flat Rate Water Heating
- Diesel

This segment of the market has typically shown very minor variations and had a very low growth rate in the past until 1998 when it changed course and started to exhibit a steadily rising rate (Figure 3.22).

[19] This section is based on Manitoba Hydro. Electric Load Forecast 2009/10 to 2029/30, May, 2009.

58

58

Typical space & water heating costs

Average single family residence at rates in effect November 1, 2010

1

Wondering about your energy options for heating?

1. Consult the charts to identify the costs of your current home heating and water heating systems.
2. Review the costs of other systems to see how your costs compare.
3. Consult the accompanying notes for guidance if you are thinking of switching systems or building a new home.

Energy rates

Natural gas:
$0.2939/cubic metre

Electricity:
$0.0657/kilowatt-hour

Fuel oil:
$0.917/litre

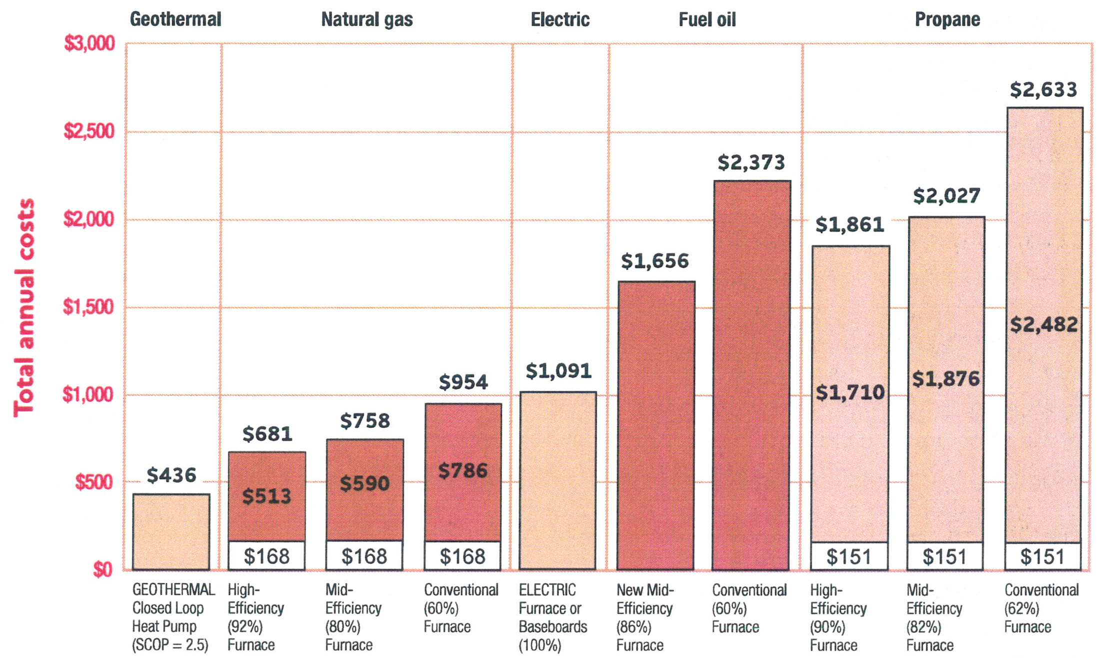
Propane:
$0.657/litre

Basic monthly charge for natural gas is **$14** (**$168** per year)

Annual propane tank rental: **$151**

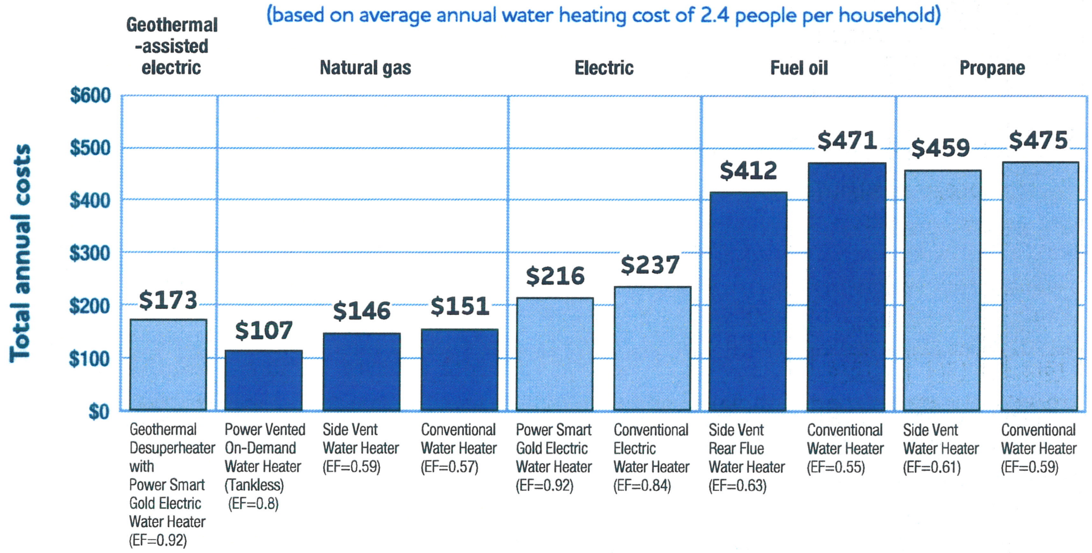
SPACE HEATING COSTS

(typical annual costs)



WATER HEATING COSTS

(based on average annual water heating cost of 2.4 people per household)



Manitoba Hydro
POWER SMART

Typical space & water heating costs

Average single family residence at rates in effect November 1, 2010

2

Weigh your options

The home heating costs shown in the chart are based on the amount of gas used to heat the average natural gas-heated home served by Manitoba Hydro. This average home is about 1200 square feet and uses a mid-efficiency furnace and conventional gas water heater. Your heating costs may differ due to a variety of factors, such as weather, heating equipment, insulation levels, air tightness and lifestyle. Water-heating costs are based on typical usage of the average Manitoba household of 2.4 people.

Annual cost estimates

The charts present annual costs as if all energy rates remained fixed for the coming year at rates in effect on November 1, 2010.

Your actual annual costs will vary, since natural gas rates change four times a year, while propane and oil rates can change weekly. Note that Primary Gas represents the bulk of the gas used. If you buy your gas from Manitoba Hydro, the price you pay for Primary Gas is the same price we pay for the gas in the marketplace. We do not mark up the cost. Our Primary Gas rate is currently $0.160 per cubic metre. If you buy Primary Gas from a broker or Manitoba Hydro on a term contract at a fixed rate, you will continue to pay Manitoba Hydro for Supplemental Gas as well as transportation and distribution charges. The figure of $0.2939 per cubic metre of natural gas that we've used in the charts is known as a "re-bundled" effective rate that a residential customer pays to Manitoba Hydro. It includes charges for Primary and supplemental gas, as well as for transportation and distribution of the gas.

Key points if you are thinking of converting

If you decide to convert your system, consider these points:

Is it economically feasible?

Note that the costs of switching to another system to heat your home and hot water may be economically feasible only if your current system is at or near the end of its useful life, or if you are building a new home. Be sure to obtain quotations from at least three reputable heating contractors before you make your decision.

Conventional furnaces no longer manufactured

The space heating chart includes conventional natural gas, fuel oil, and propane furnaces. These conventional furnaces have not been manufactured in Canada since 1992, but they have been included because some are still in operation.

High efficiency furnaces are now required by law

Effective December 30, 2009 the Province of Manitoba enacted legislation controlling the sale and lease of gas and propane heating equipment. Visit www.greenmanitoba.ca (click on the energy tab) for more information on this regulation.

Size of electrical service

Your electrical system may need to be upgraded if you want it to carry a heating load.

Depending on the capacity of the electrical appliances and equipment currently installed, and the size of your home, the Manitoba Electrical Code will allow a maximum of 8 to 10 kilowatts of electric heating on a standard 100-amp service.

Most homes need more than this, so you would have to increase the size of your electrical service. This may involve changing your electrical panel or installing an additional one. An electrician should perform an electrical code calculation to advise whether your existing service is adequate to serve the size of furnace or baseboards required to heat your home.

Other gas appliances

If you have other appliances in your home like a range, clothes dryer, fireplace, or swimming pool heater, switching to an all-electric system may be quite costly.

Venting

If you are thinking of switching to a high-efficiency natural gas furnace, note that it will not need a chimney because it is side-wall vented.

You may also have a standard natural gas water heater, in which case the heater can be left on the chimney alone if the chimney meets the requirements of the Natural Gas Installation Code. Your heating contractor can confirm this.

Once the water heater is isolated on the old chimney, if flue gases condense in the chimney, or if back-drafting or other venting problems occur, you may need to modify your venting system.

If costly modifications are required, the simplest solution may be to replace your old natural gas water heater with a side-wall vented style gas water heater or an electric water heater.

Reduced chimney ventilation

Converting to electric heat or to a high-efficiency or mid-efficiency furnace will eliminate or minimize the uncontrolled ventilation provided by the chimney.

With a conventional furnace, warm moist air continuously exits the house through the chimney. This draws replacement cold dry air into the house through cracks in walls and around windows and doors.

Reducing or eliminating this chimney ventilation will save energy but may also increase humidity levels, reduce air quality, and change the way that air leaks into and out of your home. Homes usually become slightly more positively pressurized.

The increase in humidity and air pressure could cause frozen doors and locks, increased condensation/icing on interior surfaces of well-sealed windows, and frost build-up between the panes of poorly sealed windows.

You can minimize these effects by installing some combination of the following:

- improved weatherstripping and caulking on doors and windows
- seasonal window insulator kits (clear poly over inside windows and frames)
- a heat recovery ventilator (HRV)
- new triple-pane windows
- a ventilation system which may consist of:
  - exhaust fan(s)
  - exhaust fan(s) combined with a fresh air intake
  - heat recovery ventilator (HRV)

Manitoba Hydro
POWER SMART

Typical space & water heating costs

Average single family residence at rates in effect November 1, 2010

3

Carbon monoxide safety

If you are burning heating oil, diesel, propane, kerosene, natural gas, wood, or coal in your home, or if you have an attached garage, we recommend that you install at least one carbon monoxide detector in your home.

The building code now requires permanently mounted carbon monoxide detectors in all new homes with fuel burning appliances or attached garages.

For further details, contact us for a copy of our brochure on "Carbon monoxide safety — Because your family comes first!"

What is the payback?

Determining how many years it will take for a new heating system to pay for itself may help you reach a decision.

Determine the potential savings

Subtract the annual cost of the new heating system you are considering from the annual cost of your current heating system (check the charts).

The difference is approximately what you can expect to save each year, at current energy rates.

Determine the costs of the new system

Determine how much it will cost to buy and install the new system, along with any other adjustments required. Get quotations from three reputable contractors.

Factor in the cost of financing, if necessary.

Determine the payback

Divide the estimated cost of switching your system, by the estimated savings.

The result is the number of years it will take for the new system to pay for itself.

Explanation of technical information in the charts

- Typical annual home heating requirement (output) of 60 Gigajoules is based on Manitoba Hydro's system average for natural gas heated homes.
- Water heating usage is based on Manitoba Hydro's average electric and natural gas water heating household of 2.4 people consuming about 140 litres per day that are heated up an average temperature rise of 50 C.
- The Geothermal Assisted Electric option is based on Manitoba Hydro's field monitoring of nine homes with geothermal heating and desuperheaters where 80 per cent of the average water heating load was provided by the electric heating elements of the water tank and 20 per cent by the desuperheater.
- The cost of heating with propane includes a propane tank rental or lease charge of $151 per year for a typical 500 US gallon tank. See table below. This charge may not apply to all customers and may vary.
- The cost of heating with natural gas includes a basic monthly charge of $14 ($168 per year).
- The efficiency of heating systems is given in terms of their "seasonal" efficiency, for maximum accuracy. In the case of furnaces, for example, seasonal efficiency takes into consideration not only normal operating losses but also the fact that most furnaces rarely run long enough to reach their steady-state efficiency temperature, particularly during milder weather at the beginning and end of the heating season.
- SCOP (Seasonal Coefficient of Performance) = 2.5 appears in the home heating chart under geothermal closed loop heat pump. It refers to the Seasonal Coefficient of Performance of the heat pump over an entire heating season.

  SCOP is defined as the total heat output of the system during the heating season, divided by the total energy input to the system.

  The SCOP of a geothermal heat pump typically ranges from 2.0 to 3.0. For reference, the SCOP of an electric baseboard heater is 1.0.

  The higher the SCOP rating, the more efficient your heat pump will be in lowering your heating costs. Home heating costs with a geothermal closed loop heat pump with an SCOP of 2.0 would be $545 per year; with an SCOP of 2.5, $436 per year; and with an SCOP of 3.0, $364 per year.
- Note that the natural gas energy price reflected in the charts is a bundled price that includes Primary and supplemental gas, and transportation and distribution charges. For reference, one of the major components of the bundled price is the price of Primary Gas, at $0.160 per cubic metre. Primary Gas currently comprises 81 per cent of the gas supplied (supplemental gas is 19 per cent.)
- Taxes are not included in these calculations and costs.

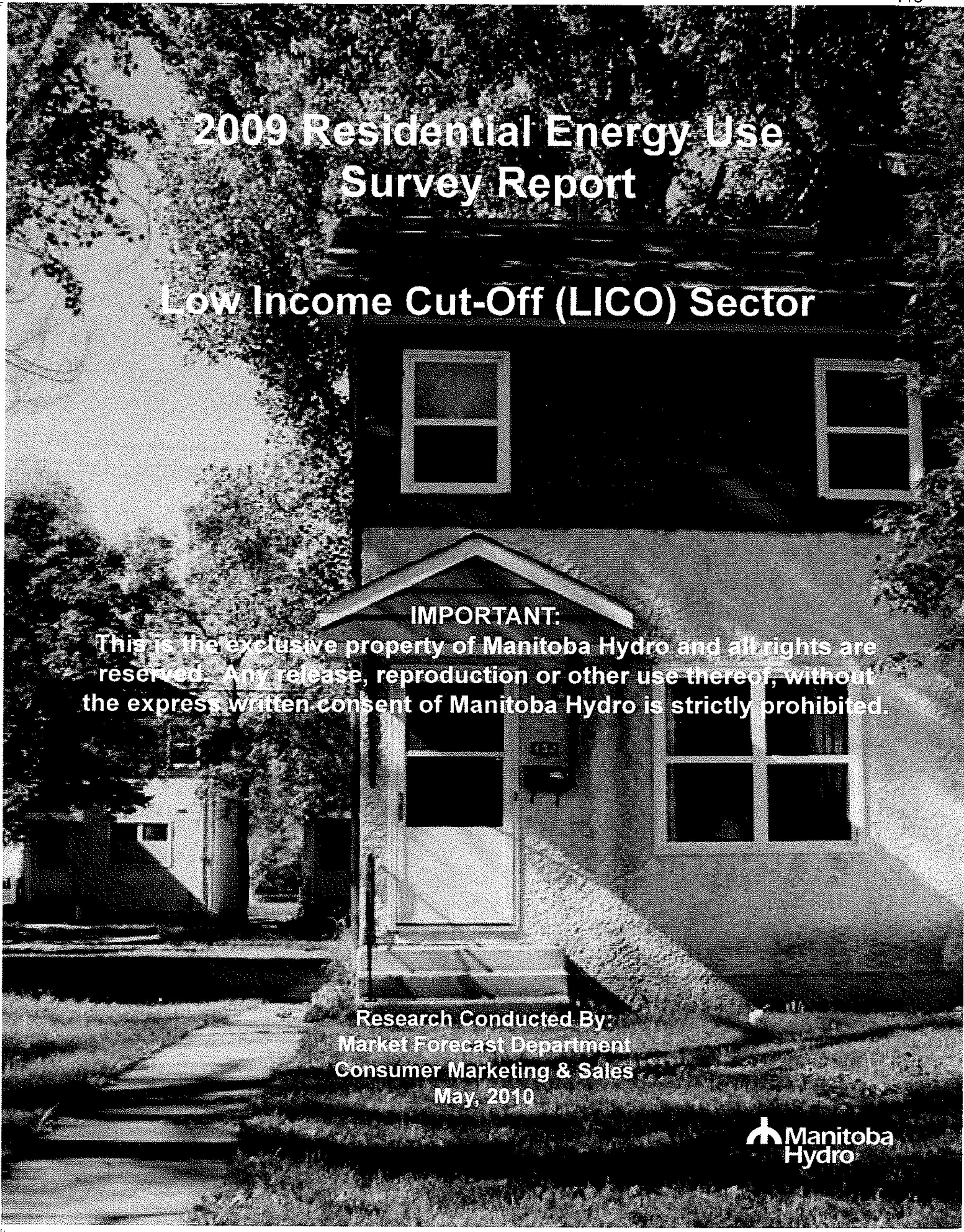
ENERGY RATES — in effect November 1, 2010

	Commodity charge	Heating value	
Natural gas	$0.2939/cubic metre	35,310	Btu/cubic metre
Electricity	$0.0657/kilowatt-hour	3,413	Btu/kilowatt-hour
Fuel oil	$0.917/litre	36,500	Btu/litre
Propane	$0.657/litre	24,200	Btu/litre

Manitoba Hydro
POWER SMART*

59

59 Appendix 50



2009 Residential Energy Use Survey Report

Low Income Cut-Off (LICO) Sector

Research Conducted By:
Market Forecast Department
Consumer Marketing & Sales
May, 2010

Manitoba Hydro

EXECUTIVE SUMMARY

Purpose

The objective of this summary is to present a detailed demographic analysis of Manitoba Hydro customers who may be defined as lower income according to Statistics Canada's Low Income Cut-Off criteria. Better definition of the size and characteristics of this market sector will assist Manitoba Hydro in the design and development of its current and future customer service offerings.

Background

Manitoba Hydro's 2009 Residential Energy Use Survey was mailed to 19,422 selected customers in November 2009. The customers were randomly selected from 439,096 customers in Manitoba Hydro's residential basic class, which is comprised of all residential customers except seasonal customers and those in diesel communities. A response rate of 24.9% was realized. The primary purpose of the survey was to gather current information on residential demographic, dwelling, appliance and energy usage characteristics. This information is utilized to create a residential sector database, which is subsequently used to assist in developing Manitoba Hydro's Load Forecast and Power Smart programs. This report provides details on a component of the survey related to the lower income market sector.

Lower income customers were classified using Statistics Canada's Low Income Cut-Off (LICO) definitions. For the purposes of this report, the low income market sector is classified into two groups: the LICO Standard (LICO-100) classification and a LICO-125 group. The LICO-100 group uses the standard Statistics Canada definition to identify the income threshold. The LICO-125 group uses the same definition as outlined by Statistics Canada except the income thresholds are increased by 25%. The following tables outline the income threshold levels used for both low income categories presented in this report.

2008 LICO-100	**Community Population**			
Number of Persons per Household	**Rural Community**	**Less than 30,000**	**30,000 to 99,999**	**500,000 and Over**
1 Person	$15,262	$17,364	$18,976	$22,171
2 Persons	$19,000	$21,615	$23,623	$27,601
3 Persons	$23,358	$26,573	$29,041	$33,933
4 Persons	$28,361	$32,264	$35,261	$41,198
5 Persons	$32,165	$36,594	$39,992	$46,727
6 Persons	$36,278	$41,272	$45,105	$52,699
7 or more Persons	$40,390	$45,950	$50,218	$58,673

2008 LICO-125	Community Populations			
Number of Persons per Household	Rural Community	Less than 30,000	30,000 to 99,999	500,000 and Over
1 Person	$19,077	$21,704	$23,733	$27,714
2 Persons	$23,750	$27,019	$29,527	$34,501
3 Persons	$23,358	$33,216	$36,300	$42,415
4 Persons	$29,197	$40,330	$44,075	$51,496
5 Persons	$35,450	$45,742	$49,989	$58,407
6 Persons	$40,205	$51,588	$56,380	$65,872
7 or more Persons	$50,487	$57,437	$62,771	$73,340

Key Findings

Demographic Characteristics

- The Manitoba Hydro residential basic population estimated to meet LICO-100 is 74,938 (17.1%); the LICO-125 population is estimated to be 105,784 (24.1%). Expanding the income definition of LICO by 25% increases the Manitoba Hydro LICO customer base by 30,846 customers, or 41.1%.

- LICO customers are about 2.5 times more likely to be one person households compared to NON-LICO households. 48.9% of LICO-100 customers (36,612 households) are one person households compared to 18.3% of NON-LICO-100 customers. 41.0% of LICO-125 customers (43,361 households) are one person households compared to 18.0% of NON-LICO-125 customers. Expanding the criteria to LICO-125 introduces 6,749 more single-person households to the lower income category.

- The LICO population has a higher proportion of individuals 65 years or older compared to the NON-LICO population. 36.0% of the LICO-100 population (26,956 people) is 65 years or older compared to 16.5% of the NON-LICO-100 population. 36.8% of the LICO-125 population (38,916 people) is 65 years or older compared to 14.4% of the NON-LICO-125 population. Expanding the criteria to LICO-125 introduces an additional 11,960 more senior individuals into the lower income population.

- Almost half the LICO occupied dwellings have an individual 65 years or older residing in them: 49.8% of LICO-100 dwellings (37,295 dwellings) have a senior resident compared to 26.7% of the NON-LICO-100 dwellings. 49.7% of LICO-125 dwellings (52,601 dwellings) have a senior resident compared to 24.5% of the NON-LICO-125 dwellings. Expanding the criteria to LICO-125 introduces 15,306 additional dwellings with senior occupants.

59

Table 4.1 Wieghted % Frequency and Population Estimates
Dwelling Characteristics across LICO versus NON-LICO Total Manitoba Hydro Residential Basic Customers

	Total Manitoba Hydro Residential Basic Customers											
	OVERALL		LICO-100		NON-LICO-100		LICO-125		NON-LICO-125		LICO (100-125)	
Population (N)	100.0%	439,096	17.1%	74,938	82.9%	364,158	24.1%	105,784	75.9%	333,312	7.0%	30,846
	%	(N)	%	(N)	%	(N)	%	(N)	%	(N)	%	(N)
Location												
Winnipeg - Central	17.3%	76,057	27.9%	20,896	15.1%	55,161	23.8%	25,130	15.3%	50,927	13.7%	4,234
Winnipeg - Suburban	37.5%	164,728	35.4%	26,501	38.0%	138,227	37.0%	39,164	37.7%	125,564	41.1%	12,663
South - Gas Available	27.5%	120,847	22.2%	16,668	28.6%	104,179	24.6%	26,068	28.4%	94,779	30.5%	9,400
South - Not Gas Available	12.9%	56,612	11.3%	8,444	13.2%	48,168	11.2%	11,836	13.4%	44,776	11.0%	3,392
North	4.7%	20,852	3.2%	2,429	5.1%	18,423	3.4%	3,585	5.2%	17,267	3.7%	1,156
Dwelling Type												
Single Detached	77.7%	341,265	64.2%	48,108	80.5%	293,157	65.0%	68,744	81.8%	272,521	66.9%	20,636
Duplex/Triplex	4.3%	18,970	5.3%	4,003	4.1%	14,967	6.6%	6,986	3.6%	11,984	9.7%	2,983
Mobile Home	2.0%	8,597	2.5%	1,842	1.9%	6,755	2.7%	2,879	1.7%	5,718	3.4%	1,037
Town/Rowhouse	3.3%	14,347	3.7%	2,765	3.2%	11,582	3.2%	3,389	3.3%	10,958	2.0%	624
Apartment Suite	12.7%	55,927	24.3%	18,220	10.4%	37,707	22.5%	23,786	9.6%	32,141	18.0%	5,566
Dwelling Ownership												
Own/Buying	86.3%	378,898	72.5%	54,327	89.1%	324,571	74.5%	78,856	90.0%	300,042	79.5%	24,529
Rent/Lease	13.7%	60,198	27.5%	20,611	10.9%	39,587	25.5%	26,928	10.0%	33,270	20.5%	6,317
Year Built												
2000 to 2009	8.2%	36,062	4.5%	3,409	9.0%	32,653	4.8%	5,067	9.3%	30,995	5.4%	1,658
1990 to 1999	7.7%	33,807	5.7%	4,286	8.1%	29,521	6.0%	6,397	8.2%	27,410	6.8%	2,111
1980 to 1989	13.5%	59,268	8.5%	6,367	14.5%	52,901	8.5%	9,027	15.1%	50,241	8.6%	2,660
1970 to 1979	18.3%	80,522	16.7%	12,500	18.7%	68,022	18.2%	19,265	18.4%	61,257	21.9%	6,765
1960 to 1969	14.6%	64,196	13.7%	10,267	14.8%	53,929	14.8%	15,661	14.6%	48,535	17.5%	5,394
1950 to 1959	13.6%	59,788	16.2%	12,117	13.1%	47,671	16.2%	17,139	12.8%	42,649	16.3%	5,022
Pre 1950	24.0%	105,453	34.7%	25,992	21.8%	79,461	31.4%	33,228	21.7%	72,225	23.5%	7,236
Average Year Built		1963		1954		1965		1956		1965		1962
Average Age (Years)		47		56		45		54		45		48
Size (Square Feet)												
900 or Less	22.3%	97,918	37.4%	28,027	19.2%	69,892	36.0%	38,082	18.0%	59,836	32.6%	10,055
901 to 1,100	23.2%	101,870	26.7%	20,008	22.5%	81,862	26.6%	28,139	22.1%	73,732	26.4%	8,130
1,101 to 1,300	18.7%	82,111	18.8%	14,088	18.7%	68,023	18.1%	19,147	18.9%	62,964	16.4%	5,059
1,301 to 1,500	10.0%	43,910	6.7%	5,021	10.7%	38,889	8.3%	8,780	10.5%	35,130	12.2%	3,759
1,501 to 1,800	10.9%	47,861	4.2%	3,147	12.3%	44,714	4.6%	4,866	12.9%	42,995	5.6%	1,719
Over 1,800	14.9%	65,425	6.2%	4,646	16.7%	60,779	6.4%	6,770	17.6%	58,655	6.9%	2,124
Average Square Feet		1,298		1,074		1,343		1,086		1,364		1,115

5.3 Average Annual Energy Use by People Per Household

Table 5.3 compares the average annual energy use by people per household between LICO and NON-LICO groups. Space heating fuel is also introduced into the analysis.

In general, LICO households use about 30% less electric energy (kW.h) on an annual basis compared to NON-LICO households. Across all LICO classifications, annual energy use increases as people per household increases. Across all LICO classifications, annual kW.h use is higher for households using electricity for space heat compared to households using non-electric fuels for space heat. LICO households use about 4% less cubic meters of natural gas, on an annual basis, than do NON-LICO households. Across all LICO classifications, annual natural gas use steadily increases as people per household increases.

On average, the LICO-100 customers consume 11,258 kW.h annually and the NON-LICO-100 group consumes 16,445 kW.h. The average annual consumption of the LICO-125 group increases to 11,785 kW.h. In the NON-LICO-125 group, the average annual consumption is 16,757 kW.h.

In the LICO-100 group, the lowest average consumption of 5,170 kW.h is by LICO-100 single person households residing in non-electrically (standard) heated dwellings. The highest average consumption of 29,645 kW.h is in LICO-100 households with 5 or more persons residing in electrically heated dwellings.

In the LICO-125 group, the lowest average consumption of 5,120 kW.h is by LICO-125 single person households residing in non-electrically (standard) heated dwellings. The highest average consumption of 29,347 kW.h is in LICO-125 households with 5 or more persons residing in electrically heated dwellings.

Table 5.3 Weighted Average Annual Energy Use by Space Heat Fuel
by People Per Household across LICO versus NON-LICO Total Manitoba Hydro Residential Customers

	Total Manitoba Hydro Residential Basic Customers					
	OVERALL	LICO-100	NON-LICO-100	LICO-125	NON-LICO-125	LICO (100-125)
Overall Average kW.h						
Overall	15,559	11,258	16,445	11,785	16,757	13,066
One Person	10,126	9,676	10,372	9,281	10,736	7,136
Two Person	15,984	11,340	16,535	12,818	16,705	14,793
Three Person	16,709	11,307	17,420	12,116	17,828	13,297
Four Person	19,592	13,928	20,287	14,478	20,467	16,109
Five or More	22,591	19,328	23,297	18,346	23,996	15,876
Average Annual kW.h Non-Electric Heat*						
Overall	10,096	6,782	10,803	7,250	11,035	8,779
One Person	5,690	5,170	5,963	5,120	6,097	4,881
Two Person	9,813	7,273	10,165	7,869	10,298	8,799
Three Person	11,863	7,467	12,489	8,230	12,821	9,362
Four Person	14,099	9,406	14,720	10,098	14,837	12,176
Five or More	16,049	11,847	16,844	11,662	17,424	11,293
Average Annual kW.h Electric Heat						
Overall	25,868	20,466	26,906	21,116	27,267	22,697
One Person	18,277	17,321	18,844	16,786	19,376	12,939
Two Person	26,214	21,618	26,613	22,951	26,843	24,253
Three Person	29,451	24,613	29,956	25,215	30,273	26,051
Four Person	32,876	27,980	33,366	27,919	33,569	27,745
Five or More	34,670	29,645	36,030	29,347	36,615	28,187
Average Annual Cubic Meters Natural Gas						
Overall	2,615	2,514	2,633	2,499	2,648	2,465
One Person	2,409	2,439	2,393	2,356	2,445	1,985
Two Person	2,591	2,485	2,605	2,499	2,612	2,518
Three Person	2,660	2,646	2,661	2,598	2,672	2,546
Four Person	2,746	2,576	2,769	2,613	2,769	2,755
Five or More	2,937	2,804	2,963	2,860	2,962	2,972

* Includes natural gas and other non-electric heating fuel customers (Standard Heat).

5.4 Average Annual Energy Use by Dwelling Type

Table 5.4 compares the average annual energy use by dwelling type between LICO and NON-LICO groups. Space heating fuel is also introduced into the analysis.

Across all LICO classifications and dwellings types, annual kW.h use is higher for dwellings using electricity for space heat compared to households using non-electric fuels for space heat. Average annual energy use is highest in single detached homes and lowest in apartment suites. This observation holds true across all LICO classifications.

In the LICO-100 group, the lowest average consumption of 3,746 kW.h is by LICO-100 apartment suite customers residing in non-electrically (standard) heated dwellings. The highest average consumption of 25,359 kW.h is by LICO-100 customers residing in electrically heated single detached dwellings.

In the LICO-125 group, the lowest average consumption of 4,653 kW.h is by LICO-125 apartment suite customers residing in non-electrically (standard) heated dwellings. The highest average consumption of 25,816 kW.h is by LICO-100 customers residing in electrically heated single detached dwellings.

59

Table 5.4 Weighted Average Annual Energy Use
by Space Heat Fuel by Dwelling Type across LICO versus NON-LICO Manitoba Hydro Residential Customers

	Total Manitoba Hydro Residential Basic Customers					
	OVERALL	LICO-100	NON-LICO-100	LICO-125	NON-LICO-125	LICO (100-125)
Average Annual kW.h Total Overall						
Overall	**15,559**	**11,258**	**16,445**	**11,785**	**16,757**	**13,066**
Single Detached	17,438	13,617	18,065	14,069	18,287	15,123
Duplex/Triplex	9,786	8,268	10,192	9,295	10,072	10,672
Mobile Home	23,602	20,088	24,562	21,736	24,543	24,666
Town/Rowhouse	11,138	9,350	11,565	9,305	11,705	9,102
Apartment Suite	5,956	5,083	6,378	5,065	6,616	5,005
Average Annual kW.h Non-Electric Heat*						
Overall	**10,096**	**6,782**	**10,803**	**7,250**	**11,035**	**8,387**
Single Detached	11,247	7,878	11,813	8,159	11,707	9,808
Duplex/Triplex	8,617	7,132	9,021	7,224	9,682	8,106
Mobile Home	12,083	9,202	13,593	9,202	13,944	----
Town/Rowhouse	7,333	6,425	7,615	6,310	7,855	6,275
Apartment Suite	4,244	3,746	4,496	4,653	5,699	3,421
Average Annual kW.h Electric Heat						
Overall	**25,868**	**20,466**	**26,906**	**21,116**	**27,267**	**22,697**
Single Detached	29,313	25,359	29,931	25,816	30,132	26,944
Duplex/Triplex	20,855	20,750	20,879	21,139	20,569	21,364
Mobile Home	24,927	22,245	25,596	23,220	25,784	24,666
Town/Rowhouse	16,965	17,858	16,838	16,054	17,165	11,946
Apartment Suite	9,039	7,715	9,626	7,874	9,800	8,430
Average Annual Cubic Meters Natural Gas						
Overall	**2,615**	**2,514**	**2,633**	**2,499**	**2,648**	**2,465**
Single Detached	2,700	2,640	2,710	2,621	2,720	2,578
Duplex/Triplex	2,289	2,291	2,289	2,314	2,276	2,348
Mobile Home	2,301	1,944	1,874	1,944	2,505	----
Town/Rowhouse	1,902	1,977	2,504	1,996	1,859	2,115
Apartment Suite	814	672	859	657	912	633

* Includes natural gas and other non-electric heating fuel customers (Standard Heat).

5.5 Space Heating Systems: Total Residential Basic

Table 5.5 shows the space heating systems of residential basic electric customers within the Manitoba Hydro provincial service territory for all LICO and NON-LICO classifications.

In terms of total space heating systems, 21.0% of LICO-100 and 21.7% of LICO-125 natural gas customers use standard efficiency natural gas furnaces compared to 16.6% of NON-LICO-100 and 16.0% of NON-LICO-125 customers.

LICO customers tend to have older space heating systems. Space heating systems that are older than 25 years are in 39.9% or 29,911 of LICO-100 occupied dwellings compared to 24.5% or 89,057 of NON-LICO-100 occupied dwellings. Space heating systems that are older than 25 years are in 38.2% or 40,458 of LICO-125 occupied dwellings compared to 23.6% or 78,510 of NON-LICO-125 occupied dwellings. The 25% income increase from the LICO definition increases the number of older heating systems by 10,547. This analysis has not filtered out apartment dwellers.

59

Table 5.5 Weighted % Frequency and Population Estimates
Space Heating System Characteristics across LICO versus NON-LICO Total Manitoba Hydro Residential Basic Customers

	Total Manitoba Hydro Residential Basic Customers											
	OVERALL		LICO-100		NON-LICO-100		LICO-125		NON-LICO-125		LICO (100-125)	
Population (N)	100.0%	439,096	17.1%	74,938	82.9%	364,158	24.1%	105,784	75.9%	333,312	7.0%	30,846
	%	(N)	%	(N)	%	(N)	%	(N)	%	(N)	%	(N)
Space Heating System*												
Hi-Efficiency Gas	19.2%	84,172	14.2%	10,637	20.2%	73,535	14.8%	15,607	20.6%	68,565	16.1%	4,970
Mid-Efficiency Gas	16.6%	72,858	13.6%	10,204	17.2%	62,654	13.7%	14,449	17.5%	58,409	13.8%	4,245
Standard-Efficiency Gas	17.3%	76,155	21.0%	15,715	16.6%	60,440	21.7%	22,967	16.0%	53,188	23.5%	7,252
Boilers	6.3%	27,783	7.1%	5,344	6.2%	22,439	7.1%	7,534	6.1%	20,249	7.1%	2,190
Electric Furnace	16.9%	74,401	10.7%	8,030	18.2%	66,371	12.0%	12,664	18.5%	61,737	15.0%	4,634
Electric Baseboard	14.0%	61,459	20.4%	15,266	12.7%	46,193	19.1%	20,192	12.4%	41,267	16.0%	4,926
Heat Pump	1.3%	5,899	0.1%	78	1.6%	5,821	0.2%	233	1.7%	5,666	0.5%	155
Other	8.3%	36,369	12.9%	9,665	7.3%	26,704	11.5%	12,138	7.3%	24,231	8.0%	2,473
% Older Than 25 Years	27.1%	118,968	39.9%	29,911	24.5%	89,057	38.2%	40,458	23.6%	78,510	34.2%	10,547
Heating System Avg. Age												
Hi-Efficiency Gas		6.0		7.5		5.7		7.6		5.6		8.0
Mid-Efficiency Gas		11.2		10.7		11.3		10.8		11.3		10.9
Standard-Efficiency Gas		28.8		34.0		27.5		32.3		27.3		28.7
Boilers		33.9		56.3		28.5		49.9		27.9		34.5
Electric Furnace		17.8		17.5		17.8		18.5		17.6		20.3
Electric Baseboard		25.9		30.1		24.5		29.3		24.2		26.9
Heat Pump		6.6		5.0		6.6		4.0		6.7		3.5
Other		34.6		42.0		31.9		38.7		32.5		26.0

* Includes Electric Heat, Natural Gas Billed, Natural Gas No Bill, and Other Heat Customers

59

Table 5.7 Weighted Population Estimates of Space Heating Systems (All Fuels)
by Dwelling Type across LICO versus NON-LICO Total Manitoba Hydro Residential Electric and Natural Gas Customers

Total Manitoba Hydro Residential Basic Customers

OVERALL - POPULATION

DWELLING TYPE	GAS-HI	GAS-MID	GAS-STD	ELEC-CFA	BASEBOARD	BOILERS	HEAT PUMP	OTHER
Single Detached	76,810	64,161	63,395	62,733	38,364	14,852	5,761	15,189
Multiplex	4,289	3,974	6,913	1,077	735	1,042	0	940
Rowhouse	2,281	2,323	2,727	806	4,862	114	0	1,234
Mobile Home	129	291	419	6,424	1,025	58	139	102
Apartment Suite	662	2,109	2,701	3,360	16,474	11,717	0	18,904
TOTAL	84,171	72,858	76,155	74,400	61,460	27,783	5,900	36,369

LICO-100 - POPULATION

DWELLING TYPE	GAS-HI	GAS-MID	GAS-STD	ELEC-CFA	BASEBOARD	BOILERS	HEAT PUMP	OTHER
Single Detached	8,957	8,580	11,802	6,339	8,298	1,888	79	2,165
Multiplex	734	939	1,574	80	253	0	0	422
Rowhouse	441	228	1,289	116	592	0	0	99
Mobile Home	48	47	210	1,204	276	58	0	0
Apartment Suite	457	409	840	291	5,847	3,398	0	6,978
TOTAL	10,637	10,203	15,715	8,030	15,266	5,344	79	9,664

NON LICO-100 - POPULATION

DWELLING TYPE	GAS-HI	GAS-MID	GAS-STD	ELEC-CFA	BASEBOARD	BOILERS	HEAT PUMP	OTHER
Single Detached	67,853	55,581	51,593	56,394	30,066	12,964	5,682	13,024
Multiplex	3,555	3,035	5,339	997	482	1,042	0	518
Rowhouse	1,840	2,095	1,438	690	4,270	114	0	1,135
Mobile Home	81	244	209	5,220	749	0	139	102
Apartment Suite	205	1,700	1,861	3,069	10,627	8,319	0	11,926
TOTAL	73,534	62,655	60,440	66,370	46,194	22,439	5,821	26,705

LICO-125 - POPULATION

DWELLING TYPE	GAS-HI	GAS-MID	GAS-STD	ELEC-CFA	BASEBOARD	BOILERS	HEAT PUMP	OTHER
Single Detached	13,303	12,193	17,051	9,520	11,046	2,195	233	3,204
Multiplex	1,357	1,043	2,933	577	334	214	0	527
Rowhouse	441	327	1,503	116	903	0	0	99
Mobile Home	48	47	210	2,015	446	58	0	55
Apartment Suite	458	839	1,270	436	7,462	5,068	0	8,253
TOTAL	15,607	14,449	22,967	12,664	20,191	7,535	233	12,138

NON LICO-125 - POPULATION

DWELLING TYPE	GAS-HI	GAS-MID	GAS-STD	ELEC-CFA	BASEBOARD	BOILERS	HEAT PUMP	OTHER
Single Detached	63,507	51,968	46,344	53,213	27,318	12,657	5,528	11,985
Multiplex	2,932	2,931	3,980	500	401	828	0	413
Rowhouse	1,840	1,996	1,224	690	3,959	114	0	1,135
Mobile Home	81	244	209	4,409	579	0	139	47
Apartment Suite	204	1,270	1,431	2,924	9,012	6,649	0	10,651
TOTAL	68,564	58,409	53,188	61,736	41,269	20,248	5,667	24,231

LICO (100-125) - POPULATION

DWELLING TYPE	GAS-HI	GAS-MID	GAS-STD	ELEC-CFA	BASEBOARD	BOILERS	HEAT PUMP	OTHER
Single Detached	4,346	3,613	5,249	3,181	2,748	307	154	1,039
Multiplex	623	104	1,359	497	81	214	0	105
Rowhouse	0	99	214	0	311	0	0	0
Mobile Home	0	0	0	811	170	0	0	55
Apartment Suite	1	430	430	145	1,615	1,670	0	1,275
TOTAL	4,970	4,246	7,252	4,634	4,925	2,191	154	2,474

Manitoba Hydro Natural Gas Residential Customers

OVERALL - POPULATION

DWELLING TYPE	GAS-HI	GAS-MID	GAS-STD	BOILERS
Single Detached	76,725	64,161	63,395	9,635
Multiplex	4,289	3,119	6,913	319
Rowhouse	2,281	2,323	2,727	0
Mobile Home	129	291	419	0
Apartment Suite	409	1,905	2,066	0
TOTAL	83,833	71,799	75,520	9,954

LICO-100 - POPULATION

DWELLING TYPE	GAS-HI	GAS-MID	GAS-STD	BOILERS
Single Detached	8,957	8,580	11,802	1,240
Multiplex	734	725	1,574	0
Rowhouse	441	228	1,289	0
Mobile Home	48	47	210	0
Apartment Suite	204	205	635	0
TOTAL	10,384	9,785	15,510	1,240

NON LICO-100 - POPULATION

DWELLING TYPE	GAS-HI	GAS-MID	GAS-STD	BOILERS
Single Detached	67,768	55,581	51,593	8,395
Multiplex	3,555	2,394	5,339	319
Rowhouse	1,840	2,095	1,438	0
Mobile Home	81	244	209	0
Apartment Suite	205	1,700	1,431	0
TOTAL	73,449	62,014	60,010	8,714

LICO-125 - POPULATION

DWELLING TYPE	GAS-HI	GAS-MID	GAS-STD	BOILERS
Single Detached	13,303	12,193	17,051	1,391
Multiplex	1,358	829	2,933	0
Rowhouse	441	327	1,503	0
Mobile Home	48	47	210	0
Apartment Suite	204	635	839	0
TOTAL	15,354	14,031	22,536	1,391

NON LICO-125 - POPULATION

DWELLING TYPE	GAS-HI	GAS-MID	GAS-STD	BOILERS
Single Detached	63,422	51,968	46,344	8,244
Multiplex	2,931	2,290	3,980	319
Rowhouse	1,840	1,996	1,224	0
Mobile Home	81	244	209	0
Apartment Suite	205	1,270	1,227	0
TOTAL	68,479	57,768	52,984	8,563

LICO (100-125) - POPULATION

DWELLING TYPE	GAS-HI	GAS-MID	GAS-STD	BOILERS
Single Detached	4,346	3,613	5,249	151
Multiplex	624	104	1,359	0
Rowhouse	0	99	214	0
Mobile Home	0	0	0	0
Apartment Suite	0	430	204	0
TOTAL	4,970	4,246	7,026	151

59

Table 6.1 % Frequency and Population Estimates
Energy Burden Range by Space Heating Fuel across LICO versus NON-LICO Total Manitoba Hydro Residential Customers

	Total Manitoba Hydro Residential Basic Customers											
	OVERALL		LICO-100		NON-LICO-100		LICO-125		NON-LICO-125		LICO (100-125)	
Population (N)	100.0%	439,096	17.1%	74,938	82.9%	364,158	24.1%	105,784	75.9%	333,312	7.0%	30,846
	%	(N)	%	(N)	%	(N)	%	(N)	%	(N)	%	(N)
Overall												
3.00% or Less	47.5%	208,458	18.7%	13,979	53.4%	194,479	19.3%	20,380	56.4%	188,078	20.8%	6,401
3.01% to 6.00%	33.2%	145,742	16.7%	12,505	36.6%	133,237	22.6%	23,861	36.6%	121,881	36.8%	11,356
6.01% to 9.00%	10.7%	47,178	25.0%	18,766	7.8%	28,412	27.9%	29,563	5.3%	17,615	35.0%	10,797
9.01% to 12.00%	4.8%	21,139	20.6%	15,440	1.6%	5,699	16.0%	16,930	1.3%	4,209	4.8%	1,490
12.01% to 15.00%	2.4%	10,634	12.4%	9,313	0.4%	1,321	9.1%	9,635	0.3%	999	1.0%	322
Over 15.00%	1.4%	5,945	6.6%	4,935	0.3%	1,010	5.1%	5,415	0.2%	530	1.6%	480
Non-Electric Heat*	N=	286,999	N=	50,428	N=	236,571	N=	71,187	N=	215,812	N=	20,759
3.00% or Less	49.6%	142,237	21.2%	10,706	55.6%	131,531	20.9%	14,871	59.0%	127,366	20.1%	4,165
3.01% to 6.00%	32.8%	94,131	14.6%	7,370	36.7%	86,761	22.8%	16,242	36.1%	77,889	42.7%	8,872
6.01% to 9.00%	10.1%	28,950	26.1%	13,154	6.7%	15,796	28.2%	20,089	4.1%	8,861	33.4%	6,935
9.01% to 12.00%	4.3%	12,337	20.6%	10,385	0.8%	1,952	15.5%	11,002	0.6%	1,335	3.0%	617
12.01% to 15.00%	2.1%	6,156	11.5%	5,795	0.2%	361	8.3%	5,880	0.1%	276	0.4%	85
Over 15.00%	1.1%	3,188	6.0%	3,018	0.1%	170	4.4%	3,103	0.0%	85	0.4%	85
Natural Gas Billed**	N=	241,106	N=	36,919	N=	204,187	N=	53,312	N=	187,794	N=	16,393
3.00% or Less	42.7%	103,065	1.1%	395	50.3%	102,670	1.7%	884	54.4%	102,181	3.0%	489
3.01% to 6.00%	37.1%	89,475	14.5%	5,371	41.2%	84,104	26.0%	13,845	40.3%	75,630	51.7%	8,474
6.01% to 9.00%	11.3%	27,177	32.9%	12,163	7.4%	15,014	35.4%	18,890	4.4%	8,287	41.0%	6,727
9.01% to 12.00%	5.0%	12,129	27.6%	10,177	1.0%	1,952	20.2%	10,795	0.7%	1,335	3.8%	618
12.01% to 15.00%	2.5%	6,071	15.7%	5,795	0.1%	276	10.9%	5,795	0.1%	276	0.0%	0
Over 15.00%	1.3%	3,189	8.2%	3,018	0.1%	171	5.8%	3,103	0.0%	85	0.5%	85
Electric Heat	N=	152,097	N=	24,510	N=	127,587	N=	34,597	N=	117,500	N=	10,087
3.00% or Less	43.5%	66,221	13.4%	3,273	49.3%	62,948	15.9%	5,509	51.7%	60,712	22.2%	2,236
3.01% to 6.00%	33.9%	51,612	21.0%	5,135	36.4%	46,477	22.0%	7,619	37.4%	43,993	24.6%	2,484
6.01% to 9.00%	12.0%	18,228	22.9%	5,612	9.9%	12,616	27.4%	9,474	7.5%	8,754	38.3%	3,862
9.01% to 12.00%	5.8%	8,802	20.6%	5,055	2.9%	3,747	17.1%	5,927	2.4%	2,874	8.6%	872
12.01% to 15.00%	2.9%	4,478	14.4%	3,518	0.8%	960	10.9%	3,756	0.6%	723	2.4%	238
Over 15.00%	1.8%	2,756	7.8%	1,917	0.7%	839	6.7%	2,311	0.4%	444	3.9%	394

* Includes natural gas and other non-electric heat customers (Standard Heat)

** Includes only natural gas customers.

60

Appendix 80

PROPOSED

RATE SCHEDULES

TO BE

EFFECTIVE

APRIL 1, 2011

November 18, 2010

Manitoba Hydro

Appendix 80

RESIDENTIAL RATES

RESIDENTIAL - *TARIFF NO. 2011-01*

Basic Charge:	$ 6.85
PLUS	
Energy Charge:	
First 900 kW.h	@ 6.52 ¢ / kW.h
Balance of kW.h	@ 6.84 ¢ / kW.h
Minimum Bill:	$ 6.85

Services over 200 amps will have $6.85 added to the Basic Charge.

Applicability:

The Residential rate is applicable for all residential purposes as follows:

a) individually metered single family dwellings including those in multiple residential projects and single or three phase farm operations served through the same meter if:

   i. the connected business load does NOT exceed 3 kW; or
   ii. the combined agricultural and residential load does NOT exceed a demand of 50 kW.

b) services for personal use outside the home, such as residential water wells, private garages, boat houses and swimming pools (use can be for household, recreational and hobby activities).

c) single metered multiple residential projects meeting all the following criteria:

   i. monthly demand does not exceed 50 kV.A;
   ii. the meter serves four or less individual suites or dwelling units;
   iii. none of the units are used for business purposes;
   iv. individual dwelling units are:
      - self-contained rental apartments with common facilities; or
      - row housing with self-contained rental dwelling units and common facilities; or
      - buildings with condominium type dwellings incorporated under *the Condominium Act*; or individual residential services within a trailer park established prior to May 1, 1969.

Appendix 81

BILL COMPARISONS

APRIL 1, 2010 RATES

VS

PROPOSED

APRIL 1, 2011 RATES

Manitoba Hydro

NOVEMBER 18, 2010

Appendix 81

Bill Comparison

Residential

Forecast Customers: 449,533

kW.h	April 1, 2010 $ / Month	April 1, 2011 $ / Month	Difference in $ / Month	Percent Change
250	$22.80	$23.15	$0.35	1.54%
750	$54.70	$55.75	$1.05	1.92%
1 000	$70.84	$72.37	$1.53	2.16%
2 000	$136.54	$140.77	$4.23	3.10%
5 000	$333.64	$345.97	$12.33	3.70%

Residential Seasonal

Forecast Customers: 20,930

kW.h	April 1, 2010 $ / Summer	April 1, 2011 $ / Summer	Difference in $ / Summer	Percent Change
250	$98.15	$98.50	$0.35	0.36%
750	$130.05	$131.10	$1.05	0.81%
1 000	$146.00	$147.40	$1.40	0.96%
2 000	$209.80	$212.60	$2.80	1.33%
5 000	$401.20	$408.20	$7.00	1.74%

Residential Diesel

Forecast Customers: 587

kW.h	April 1, 2010 $ / Month	April 1, 2011 $ / Month	Difference in $ / Month	Percent Change
250	$22.80	$23.15	$0.35	1.54%
750	$54.70	$55.75	$1.05	1.92%
1 000	$70.84	$72.37	$1.53	2.16%
2 000	$136.54	$140.77	$4.23	3.10%
5 000*	$1,374.64	$1,378.87	$4.23	0.31%

* Does not reflect proposed changes to the Full Cost portion of the rate currently before the Public Utilities Board.

61

MIPUG/MH I-20

Reference: Rate Proposals – Residential Customers

d) Please provide the simple average and median kW.h usage by month for Residential customers. Please provide the information separated by electric heating customers and non-electric heating customers.

ANSWER:

The following table provides the average use of Residential Standard and Residential All-Electric customers (exclusive of seasonal, diesel and flat rate water heating loads) for the 2006/07 fiscal year. Manitoba Hydro does not keep statistics on median kW.h usage.

Month	Standard Average Use	All-Electric Average Use
March 2007	952	3,038
February 2007	1,125	3,827
January 2007	1,094	3,376
December 2006	926	2,885
November 2006	832	2,268
October 2006	758	1,565
September 2006	795	1,126
August 2006	899	1,008
July 2006	877	1,038
June 2006	729	1,224
May 2006	741	1,350
April 2006	782	2,260

RCM/TREE/MH I-8

Proposed Rate Structure

Reference: Bill Comparisons, Appendices 10.5 and 10.6

f) Please indicate whether MH has considered proposing seasonally-differentiated rates for Residential and General Service non-demand rates

i. If not, explain why not.

ANSWER:

Manitoba Hydro has done some preliminary review of seasonally-differentiated rates for the Residential rate class. One method looked at increasing the size of the first block rate in the winter months and reducing the first block size in the summer months. This method would have the advantage of mitigating impacts on winter bills for those customers who have no choice but to use electricity to heat their homes.

In terms of customer impacts of a seasonally differentiated rate, the winter bill advantage would be offset, at least in part, by higher summer bills. Further, because the larger winter block shelters a larger portion of residential energy from the second block price, the second block price may have to be higher in order to capture the same revenue as a rate design which is not seasonally differentiated.

From a billing administration perspective, implementing a seasonally-differentiated rate is more complex than the current rate structure. However compared to other potential TOU rate structures it is relatively easy to implement and for customers to understand. All residential services would be affected with two rate changes a year. Billing issues could be problematic for customers in the two rate change months as customers may notice the billing difference and would be more apt to contact the Contact Centre and/or their district office with enquiries. The major complaint would be unfairness of estimated bills and proration of bills.

62

62

Appendix 86

2010 Power Smart Plan

Manitoba Hydro

POWER SMART*

December 2010

*Manitoba Hydro is a licensee of the Official Mark

62

2.3 Electric DSM Cost Effectiveness

The following table outlines the cost effectiveness of the electric program offerings provided in the 2010 Power Smart Plan.

Power Smart Plan Economic Cost Effectiveness Ratios and Levelized Costs
2010/11 - 2037/38

	RIM	LUC (¢/kW.h)	PC	Customer Payback (years)
Residential				
New Home Program	1.6	0.1	1.2	7.9
Home Insulation Program	1.6	1.9	3.5	2.1
Water and Energy Saver Program	1.0	1.8	19.6	n/a ^
Lower Income Energy Efficiency Program (Power Smart & AEF Budget) >	0.9	4.9	6.0	n/a ^
Lower Income Energy Efficiency Program (Power Smart)	1.3	1.3	5.0	1.5
EE Light Fixtures	0.8	4.6	7.2	n/a ^
Residential CFL Program	1.3	1.0	10.6	0.0
Fridge Recycling Program	0.8	2.3	3.0	2.6
Residential Programs Total	1.3	1.4	3.4	1.1
Residential Market Effects				
Residential Appliance Program	1.2	1.0	4.5	2.4 *
Commercial				
Commercial Lighting Program	1.4	1.9	2.3	2.2
Commercial Custom Measures Program	1.3	2.4	2.7	2.9
Commercial Windows Program	1.7	1.7	3.6	1.5
Commercial HVAC Program - Chiller	1.0	1.0	1.6	4.6 *
Commercial Parking Lot Controller Program	1.2	1.9	3.0	1.1
City of Winnipeg Power Smart Agreement	1.6	0.0	7.6	0.1
Commercial Refrigeration Program	1.2	1.2	3.7	1.3
Commercial Insulation Program	2.0	0.9	4.4	1.9
Commercial Earth Power Program	1.9	1.4	1.7	7.4 *
Commercial New Construction Program	1.5	0.9	3.5	2.6 *
Commercial Building Optimization Program	1.7	1.4	3.9	1.3
Internal Retrofit Program	1.0	8.5	1.0	n/a ^
Agricultural Heat Pad Program	1.8	0.3	n/a	n/a * ^
Power Smart Energy Manager Program	1.0	2.7	1.4	2.9
Commercial Kitchen Appliance Program	1.3	2.2	6.5	n/a * ^
Commercial Clothes Washers Program	1.5	4.0	1.8	4.5 *
Network Energy Management Program	1.0	1.0	3.1	0.2 *
Power Smart Shops	0.9	3.3	73.1	0.0
CO2 Sensors	1.6	0.4	3.6	1.0 *
Commercial Programs Total	1.4	2.0	2.4	2.2
Commercial Market Effects				
Commercial Rinse & Save Program	1.5	0.0	n/a	n/a *
Industrial				
Performance Optimization Program	1.2	1.9	2.3	3.1
Emergency Preparedness Program	1.2	4.7	2.4	1.0
Industrial Programs Total	1.2	2.5	2.4	2.6
Energy Efficiency Total	1.3	2.0	2.6	1.9
Load Management				
Curtailable Rate Program	0.9	n/a	n/a	n/a
Customer Self-Generation				
BioEnergy Optimization Program	1.4	1.9	1.3	0.9
Overall Portfolio Ratio	1.2	2.5	2.7	0.9

Notes:
* Program assumption includes future Market Transformation and/or Participant Re-investment
^ Program with nil or negative net customer costs
> See section 6.1 for detail on Affordable Energy Fund Budget
1) Overall RIM, PC and Payback ratios includes Curtailable Rates Program / Overall LUC does not include Curtailable Rate Program
2) Overall benefit/cost ratios do not include savings due to Customer Service Initiatives
3) Overall benefit/cost ratios and utility costs include support and contingency costs
4) PC and Customer Payback tests include water savings benefits
5) Overall RIM and LUC includes funding from the Affordable Energy Fund

62

6 Other Internal Demand Side Management Funding

6.1 Affordable Energy Fund

The Affordable Energy Fund is an internal fund established as a result of the Winter Heating Cost Control Act. The purpose of the Fund is to provide support for programs and services that achieve specific objectives outlined under the Act including encouraging energy efficiency and conservation through programs and services for rural and northern Manitobans, low income customers and seniors and encouraging the use of alternative energy sources such as renewable energy.

Affordable Energy Fund - Budget

Manitoba Hydro established the Affordable Energy Fund following the passing of the Winter Heating Cost Control Act on November 20, 2006 in the Manitoba Legislature. The Affordable Energy Fund supports Manitoba Hydro's sustainable development initiatives.

The following projects and associated funding levels have been approved for support by the Affordable Energy Fund:

Affordable Energy Fund Budget
(Millions)

	Total Budget
Lower Income Program	19.0
Geothermal Support	6.0
Community Support and Outreach	0.8
Oil and Propane Heated Homes	0.3
Special Projects	
Residential ecoEnergy Audits	0.5
Oil and Propane Furnace Replacement	0.2
Solar Water Heaters	0.3
Residential Loan	1.4
AEF Energy Efficiency Sub-total	28.4
Community Energy Development	8.0
TOTALS	$36.4

As of March 31st, 2010 approximately $6 million of the Affordable Energy Fund had been spent, leaving the remaining $30 to be allocated over the 2010/11 to 2024/25 horizon.

Affordable Energy Fund Budget
(Millions)

	Total Budget	Expeditures to Date	Remaining Budget
Lower Income Program	19.0	3.0	16.0
Geothermal Support	6.0	1.1	4.9
Community Support and Outreach	0.8	0.2	0.6
Oil and Propane Heated Homes	0.3	0.2	0.1
Special Projects			
Residential ecoEnergy Audits	0.5	0.4	0.2
Oil and Propane Furnace Replacement	0.2	0.0	0.1
Solar Water Heaters	0.3	0.2	0.1
Residential Loan	1.4	0.1	1.3
AEF Energy Efficiency Sub-total	28.4	5.2	23.2
Community Energy Development	8.0	0.8	7.3
TOTALS	$36.4	$6.0	$30.4

The following table identifies the programs and associated funding levels that the Affordable Energy Fund will support over the Power Smart Planning horizon.

Affordable Energy Fund Budget
(Millions, 2010 $)

	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	Total
Lower Income Program	3.5	6.2	6.2	0.0	0.0	0.0	0.0	16.0
Geothermal Support	0.1	0.1	0.1	2.3	2.3	0.1	0.0	4.9
Community Support and Outreach	0.2	0.1	0.1	0.1	0.1	0.1	0.0	0.6
Oil and Propane Heated Homes	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.1
Special Projects								
Residential ecoEnergy Audits	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.2
Oil and Propane Furnace Replacement	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1
Solar Water Heaters	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.1
Residential Loan	0.5	0.4	0.3	0.1	0.0	0.0	0.0	1.3
AEF Energy Efficiency Sub-total	4.6	6.8	6.7	2.5	2.4	0.1	0.1	23.2
Community Energy Development	0.0	3.6	3.6	0.0	0.0	0.0	0.0	7.3
Annual Budget	4.6	10.4	10.3	2.5	2.4	0.1	0.1	30.4
Cumulative Budget, 2010 - 2024	$4.6	$15.0	$25.3	$27.8	$30.2	$30.3	$30.4	$30.4

The Affordable Energy Fund supports the Lower Income Energy Efficiency Program with a cumulative investment of $16 million for the period of 2010/11 to 2012/13.

The Affordable Energy Fund provides funding to subsidize the interest rate for Residential Earth Power Loan participants. The Fund is being used to reduce the interest rate for program participants from 6.5 to 4.9 percent for the first five years of the loan term. The Fund is expected to provide a cumulative investment of $5 million over the period of 2010/11 to 2016/17.

The Affordable Energy Fund provides support for community energy development. This project will encourage the development of 5 MW of community-based energy projects in Manitoba and is expected to provide a cumulative investment of $7 million over the period of 2011/12 to 2012/13.

The Affordable Energy Fund provides funding for additional resources for the purpose of encouraging rural and northern customers to participate in Power Smart initiatives. The Fund is expected to provide a cumulative investment of $0.6 million over the period of 2010/11 to 2015/16.

The Affordable Energy Fund provides incentives to customers with wood, oil or propane heating who install insulation in their homes. The incremental costs associated with these customers participating in the Home Insulation Program will be allocated to the Affordable Energy Fund. The Fund is expected to provide a cumulative investment of $0.1 million in 2010/11. The estimated savings of the other fuel types resulting from the installation of insulation in customer homes are provided in the next section of this report.

The Affordable Energy Fund contributes the incremental costs associated with providing Manitoba Hydro's In-home Energy Assessment service under the Federal ecoENERGY Retrofit program to rural and northern Manitobans. The Fund is expected to provide a cumulative investment of $0.2 million in 2010/11.

Manitoba Hydro extended the eligibility for the Power Smart Furnace Replacement Program to those customers upgrading an oil or propane furnace to a high efficiency electric or natural gas

7 Total Internal Demand Side Management Budget

The Total Internal Demand Side Management Budget includes the following internal sources:

- Electric Power Smart Utility Budget - $414 million (as outlined in Section 2.2)
- Natural Gas Power Smart Utility Budget- $130 million (as outlined in Section 3.2)
- Affordable Energy Fund Budget - $23 million (as outlined in Section 6.1)
- Lower Income Furnace Replacement Budget - $5 million (as outlined in Section 6.2)

The following table outlines the total projected DSM budget including all internal sources of funding to 2024/25. A total investment of $ 572 million is planned for the period of 2010/11 to 2024/25.

Total DSM Budget
2010/11 - 2024/25
(Millions, 2010 $)

	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	Total
Electric DSM																
Electric Power Smart	37.8	38.8	39.9	39.5	37.1	30.3	25.8	23.8	22.8	21.2	20.5	20.4	20.2	20.1	16.0	414.2
Affordable Energy Fund	1.3	1.5	1.6	2.4	2.4	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	9.4
Annual Electric Budget	$39.1	$40.3	$41.5	$41.9	$39.4	$30.5	$25.9	$23.8	$22.8	$21.2	$20.5	$20.4	$20.2	$20.1	$16.0	$423.5
Natural Gas DSM																
Natural Gas Power Smart	11.9	12.7	13.1	11.1	11.0	10.7	10.1	7.9	6.3	5.8	5.8	5.8	5.8	5.8	5.8	129.6
Affordable Energy Fund	3.2	5.2	5.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	13.7
Lower Income Furnace Replacement Budget	1.4	1.9	1.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5.2
Annual Natural Gas Budget	$16.4	$19.8	$20.1	$11.2	$11.1	$10.7	$10.1	$7.9	$6.3	$5.8	$5.8	$5.8	$5.8	$5.8	$5.8	$148.4
Oil and Propane DSM																
Affordable Energy Fund	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2
Annual Oil and Propane Budget	$0.1	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.2
Manitoba Hydro Annual Budget	$55.6	$60.2	$61.6	$53.1	$50.5	$41.2	$35.9	$31.8	$29.1	$27.0	$26.3	$26.2	$26.0	$25.9	$21.8	
Cumulative Budget 2010-2024	$55.6	$115.8	$177.4	$230.5	$281.0	$322.2	$358.2	$389.9	$419.0	$446.0	$472.3	$498.5	$524.4	$550.3	$572.1	$572.1

63

PUB/MH I-118

Subject: Tab 9: Demand Side Management

Reference: Appendix 9-1 Page 109, 2009 Power Smart Plan detailed savings and costs

Please provide a tabulation of the Levelized Utility Cost [¢/kW.h] and the corresponding revenue gains [difference between export sales and foregone domestic revenue] for each incentive program.

ANSWER:

	2009 LUC (c/kW.h)	Revenue Gain (c/kW.h)
RESIDENTIAL		
Incentive Based		
New Home Program	0.57	0.93
Home Insulation Program	2.22	3.65
Water and Energy Saver Program	1.33	-0.01
Lower Income Energy Efficiency Program	0.64	-0.97
Residential HE Furnace & Boiler Program	0.00	2.29
EE Light Fixtures	5.30	0.64
Residential CFL Program	0.75	0.59
Fridge Recycling Program	2.46	-0.93
Residential Appliance Program	0.68	0.28
COMMERCIAL		
Commercial Lighting Program	1.71	2.03
Commercial Custom Measures Program	2.46	1.92
Commercial Windows Program	4.54	3.67
Commercial HVAC Program - Chiller	0.99	0.24
Commercial Parking Lot Controller Progran	0.49	1.64
City of Winnipeg Power Smart Agreement	1.11	1.88
Commercial Rinse & Save Program	0.25	0.34
Commercial Refrigeration Program	0.60	0.82
Commercial Insulation Program	2.50	4.37
Commercial Earth Power Program	2.31	4.03
Commercial New Construction Program	3.15	1.62
Commercial Building Optimization Prograrr	1.42	3.04
Internal Retrofit Program	2.17	7.58
Agricultural Heat Pad Program	0.24	1.67
Power Smart Energy Manager Program	0.60	1.06
Commercial Kitchen Appliance Program	2.57	2.48
Commercial Clothes Washers Program	3.07	5.31
Network Energy Management Program	1.38	0.27
Power Smart Shops	2.12	0.17
CO2 Sensors	0.70	0.99
INDUSTRIAL		
Performance Optimization Program	1.58	1.77
Emergency Preparedness Program	6.26	3.23
CUSTOMER SELF-GENERATION		
Bioenergy Optimization Program	1.63	1.88
LOAD MANAGEMENT		
Curtailable Rate Program	n/a	n/a

PUB/MH I-132

Subject: Tab 9: Demand Side Management
Reference: 2009 Power Smart Plan Section 4.3 – Economic Effectiveness Ratios

a) **The 2009 Power Smart Plan provides the results of the TRC, RIM, and LUC cost-effectiveness measures, but does not provide the inputs to undertake the calculation of the ratios for these measures. Please provide the following for each of the Incentive – based electric DSM program:**

   i. **The revenue realized by MH from conserved electricity sold in the export market;**
   ii. **The avoided cost of new infrastructure;**
   iii. **The total program administration costs, and utility program administration costs [if different];**
   iv. **The incremental product costs;**
   v. **The revenue loss resulting from reduced consumption;**
   vi. **The cost of incentives; and**
   vii. **The energy saved.**

ANSWER:

The following table outlines the inputs for the various cost-effectiveness measures of each incentive-based program in the 2009 Power Smart Plan. One marginal benefit value is provided for (i) and (ii) as these values are not independently calculated. As a proxy, it is estimated that 75% of the marginal value is from export revenue and 25% of the marginal value is from the avoided cost of new infrastructure.

	Marginal Benefits		Program Admin Costs		Incremental Product Cost	Revenue Loss	Incentives		Energy Saved
	INPUT i & ii		INPUT iii		INPUT iv	INPUT v	INPUT vi		INPUT vii
	PV of Marginal Benefit	PV of Non-Energy (Water) Benefits	PV of Utility Program Admin Costs	PV of AEF Program Admin Costs	PV of Incremental Product Costs	PV of Revenue Loss	PV of Utility Incentives	PV of AEF Incentives	PV of Energy Saved @ Gen (kW.h)
RESIDENTIAL									
New Home	$27,465,817	$0	$1,179,447	$0	$13,268,399	$17,841,851	$498,404	$0	295,615,532
Home Insulation	$44,139,657	$0	$2,303,238	$0	$7,717,119	$20,585,204	$5,303,602	$0	343,077,994
Water and Energy Saver	$21,799,156	$14,389,900	$2,523,149	$0	$1,228,992	$16,375,333	$1,245,158	$0	283,586,906
Lower Income	$19,820,833	$2,510,036	$337,976	$1,733,245	$11,398,668	$12,528,866	$1,025,270	$4,775,902	213,886,387
HE Furnace & Boiler	$1,031,475	$0	$0	$0	$1,340,677	$555,091	$0	$0	9,526,204
EE Light Fixtures	$1,983,289	$0	$1,013,293	$0	$62,403	$1,320,823	$368,489	$0	26,086,831
Residential CFL	$50,860,299	$0	$1,709,685	$0	$1,612,649	$34,415,732	$3,005,910	$0	627,476,240
Fridge Recycling	$24,527,762	$0	$7,329,721	$0	$8,102,463	$22,014,257	$2,193,891	$0	387,605,783
Appliances	$3,834,486	$8,437,540	$326,824	$0	$2,721,431	$2,741,979	$0	$0	48,027,994
COMMERCIAL									
Lighting	$347,400,207	$0	$18,719,997	$0	$120,922,999	$189,859,470	$40,935,892	$0	3,488,418,075
Custom Measures	$6,702,125	$0	$825,977	$0	$1,836,503	$3,409,991	$1,237,406	$0	83,999,761
Windows	$18,886,559	$0	$4,827,354	$0	$3,247,172	$8,380,272	$2,320,877	$0	157,555,226
HVAC - Chiller	$7,876,706	$0	$72,663	$0	$4,500,017	$5,492,316	$1,649,427	$0	173,096,889
Parking Lot Controller	$7,876,418	$0	$181,073	$0	$1,955,936	$4,106,607	$361,404	$0	109,875,846
City of Winnipeg Agreement	$642,251	$0	$5,662	$0	$72,568	$358,018	$66,906	$0	6,566,394
Rinse & Save	$789,893	$1,014,745	$12,291	$0	$16,540	$551,210	$18,354	$0	12,044,790
Refrigeration	$38,098,408	$0	$1,038,279	$0	$5,487,109	$24,601,577	$1,900,401	$0	486,802,139
Insulation	$42,030,068	$0	$4,827,354	$0	$8,470,339	$18,355,272	$2,705,037	$0	301,643,229
Earth Power	$21,908,731	$0	$1,613,844	$0	$6,634,094	$9,368,813	$2,429,589	$0	175,206,593
New Construction	$31,251,333	$0	$2,602,627	$0	$18,389,714	$17,980,300	$7,980,897	$0	335,927,288
Building Optimization	$14,887,954	$0	$595,513	$0	$2,364,756	$7,011,829	$1,349,792	$0	136,823,103
Internal Retrofit	$31,277,686	$0	$6,715,467	$0	$20,791,677	$0		$0	309,398,949
Agricultural Heat Pad	$7,123,948	$0	$49,510	$0	$0	$3,706,116	$183,776	$0	98,139,001
Power Smart Energy Manager	$8,117,762	$0	$828,698	$0	$1,787,000	$4,490,749	$73,849	$0	150,886,092
Kitchen Appliances	$3,884,549	$3,145,983	$101,053	$0	$1,921,803	$2,057,453	$783,472	$0	34,460,247
Clothes Washers	$3,596,898	$1,664,163	$184,420	$0	$2,413,318	$1,656,657	$416,347	$0	19,589,824
Network Energy Management	$10,973,062	$0	$292,332	$0	$2,868,248	$7,819,628	$1,768,838	$0	149,354,594
Power Smart Shops	$8,040,354	$1,453,679	$1,497,172	$0	$3,486,023	$5,859,049	$695,483	$0	103,463,120
CO2 Sensors	$453,820	$0	$18,171	$0	$73,995	$253,540	$43,323	$0	8,766,464
INDUSTRIAL									
Performance Optimization	$146,211,813	$0	$9,930,423	$0	$28,960,435	$76,602,313	$19,696,471	$0	1,869,852,327
Emergency Preparedness	$50,562,529	$0	$2,149,227	$0	$19,127,566	$29,094,777	$14,982,101	$0	273,600,739
Customer Self Generation									
Bioenergy Optimization	$93,377,793	$0	$2,478,727	$0	$54,528,780	$46,946,422	$17,549,580	$0	1,229,772,822

PUB/MH I-132

Subject: **Tab 9: Demand Side Management**
Reference: **2009 Power Smart Plan Section 4.3 – Economic Effectiveness Ratios**

b) Please explain the methodology for determining the Present Value of each of these inputs in the cost-effectiveness ratios including the various required input factors such as discount rate used. Tab 10: Proposed Rates And Customer Impacts

ANSWER:

The Present Value of each input in the cost-effectiveness ratios used Manitoba Hydro's real weighted average cost of capital at the time the 2009 Power Smart Plan was created (6.1%) discounted over a 30 year period.

64

PUB/MH I-121

Subject: Tab 9: Demand Side Management
Reference: City of Winnipeg Power Smart Agreement

a) **Please provide a summary of the terms of the agreement with the City of Winnipeg on DSM programs and the financial implications of the program to Manitoba Hydro**

ANSWER:

Manitoba Hydro and the City of Winnipeg entered into a Power Smart Agreement on September 3, 2002 with an objective to capture energy efficient opportunities within the City's facilities, with a minimum target of reducing the City's energy bill by $800,000 annually. The program has spent $10.6 million to date, which includes $3.2 million in commitment payments, $6.4 million in energy efficiency project costs, and $1.0 million in program administration and management fees. In addition, Manitoba Hydro realizes the benefits associated with increased electricity export revenues.

64

PUB/MH I-121

Subject: Tab 9: Demand Side Management
Reference: City of Winnipeg Power Smart Agreement

b) Please indicate the amount of savings realized in each of the years 2002 through 2009 and that forecast for 2010, 2011 and 2012.

ANSWER:

Project Year	Annual Savings	
2002/03	$13,529	
2003/04	$55,921	
2004/05	$140,147	
2005/06	$626,229	
2006/07	$770,906	
2007/08	$757,792	
2008/09	$874,859	
2009/10	$900,000	forecast
2010/11	$920,000	forecast
2011/12	$940,000	forecast

65

PUB/MH II-105

Subject: **Tab 9: Demand Side Management**
Reference: **PUB/MH I-112 (a) & (b) Low Income Households**

a) **Please provide tables based on the new demographic information which indicates the number of qualified households (LICO) by household size and rural and urban community by size.**

ANSWER:

The following table provides the estimated number of LICO customers.

LICO						
		Urban				
	Rural	**Less than 30,000**	**Between 30,000 - 99,999**	**Between 100,000 - 499,999**	**500,000 + over**	**Total**
1 person	11,424	3,148	982	0	21,058	36,612
2	2,776	2,155	808	0	15,444	21,183
3	1,179	78	348	0	4,622	6,227
4	976	387	268	0	4,338	5,969
5	908	224	40	0	1,712	2,884
6	256	0	0	0	465	721
7 or more	1,047	0	0	0	295	1,342
Total	18,566	5,992	2,446	0	47,934	74,938

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PUB/MH II-105

Subject: **Tab 9: Demand Side Management**
Reference: **PUB/MH I-112 (a) & (b) Low Income Households**

b) **Please provide a similar table in (a) for LICO 125%.**

ANSWER:

The following table provides the estimated number of LICO-125 customers.

LICO-125						
		Urban				
	Rural	Less than 30,000	Between 30,000 - 99,999	Between 100,000 - 499,999	500,000 + over	Total
1 person	11,424	4,904	1,295	0	25,738	43,361
2	8,743	3,932	1,974	0	22,392	37,041
3	1,556	671	348	0	7,914	10,489
4	1,450	927	346	0	5,256	7,979
5	1,041	329	98	0	2,485	3,953
6	541	0	143	0	754	1,438
7 or more	1,047	0	0	0	476	1,523
Total	25,802	10,763	4,204	0	65,015	105,784

<u>**PUB/MH I-109**</u>

Subject: **Tab 9: Demand Side Management**
Reference: **Appendix 9.1 LIEEP**

a) **Please provide demographic data on Low income households broken down by dwelling type and ownership [actual numbers and % of total]**

ANSWER:

The following two tables are based on data obtained from the 2003 survey.

	LICO-Standard		
DWELLING TYPE	**OWN**	**RENT**	**TOTAL**
Single Detached	45,467	5,344	50,811
Multiplex	3,961	2,876	6,836
Rowhouse	1,410	3,066	4,476
Mobile Home	2,613	507	3,120
Apartment Suite	2,145	14,762	16,907
TOTAL	55,596	26,555	82,151
Single Detached	81.8%	20.1%	61.9%
Multiplex	7.1%	10.8%	8.3%
Rowhouse	2.5%	11.6%	5.4%
Mobile Home	4.7%	1.9%	3.8%
Apartment Suite	3.9%	55.5%	20.6%
TOTAL	100.0%	100.0%	100.0%

	LICO-125		
DWELLING TYPE	**OWN**	**RENT**	**TOTAL**
Single Detached	54,426	5,696	60,122
Multiplex	4,704	3,001	7,706
Rowhouse	1,510	3,066	4,577
Mobile Home	2,993	507	3,500
Apartment Suite	2,145	15,147	17,292
TOTAL	65,779	27,417	93,197
Single Detached	82.7%	20.8%	64.5%
Multiplex	7.1%	11.0%	8.3%
Rowhouse	2.3%	3.3%	4.9%
Mobile Home	3.5%	0.5%	3.8%
Apartment Suite	4.5%	16.3%	18.5%
TOTAL	100.0%	100.0%	100.0%

The following two tables are based on data obtained from the 2009 survey.

	LICO-Standard		
DWELLING TYPE	**OWN**	**RENT**	**TOTAL**
Single Detached	44,200	3,908	48,108
Multiplex	2,809	1,194	4,003
Rowhouse	1,327	1,438	2,765
Mobile Home	1,787	55	1,842
Apartment Suite	4,205	14,015	18,220
TOTAL	54,328	20,610	74,938
Single Detached	81.4%	19.0%	64.2%
Multiplex	5.2%	5.8%	5.3%
Rowhouse	2.4%	7.0%	3.7%
Mobile Home	3.3%	0.3%	2.5%
Apartment Suite	7.7%	68.0%	24.3%
TOTAL	100.0%	100.0%	100.0%

	LICO-125		
DWELLING TYPE	**OWN**	**RENT**	**TOTAL**
Single Detached	64,024	4,720	68,744
Multiplex	5,164	1,822	6,986
Rowhouse	1,735	1,654	3,389
Mobile Home	2,777	102	2,879
Apartment Suite	5,156	18,630	23,786
TOTAL	78,856	26,928	105,784
Single Detached	81.2%	17.5%	65.0%
Multiplex	6.5%	6.8%	6.6%
Rowhouse	2.2%	6.1%	3.2%
Mobile Home	3.5%	0.4%	2.7%
Apartment Suite	6.5%	69.2%	22.5%
TOTAL	100.0%	100.0%	100.0%

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Gb

PUB/MH II-103

Subject: **Tab 9: Demand Side Management**
Reference: **PUB/MH I-111 (a)**

With respect to LIEEP electric households Please provide an updated table including all households where spending had been incurred including Island Lake participation when available

ANSWER:

LIEEP Electric Spending			
	2005-06		
Category	PS	Bill 11	Total
Community	$ -	$ -	$ -
Individual	$ -	$ -	$ -
First Nations	$ 5,000	$ -	$ 5,000
Total 2005-06	**$ 5,000**	**$ -**	**$ 5,000**
	2006-07		
Category	PS	Bill 11	Total
Community	$ 38,453	$ 61,067	$ 99,520
Individual	$ 58,523	$ -	$ 58,523
First Nations	$ 12,897	$ 161,622	$ 174,519
Total 2006-07	**$ 109,873**	**$ 222,690**	**$ 332,563**
	2007-08		
Category	PS	Bill 11	Total
Community	$ 158,947	$ 177,922	$ 336,869
Individual	$ 62,705	$ 7,811	$ 70,516
First Nations	$ 2,107	$ (18,217)	$ (16,110)
Total 2007-08	**$ 223,758**	**$ 167,517**	**$ 391,275**

Category	2008-09 PS	2008-09 Bill 11	2008-09 Total
Community	$ 110,231	$ 148,379	$ 258,610
Individual	$ 93,345	$ 245,790	$ 339,134
First Nations	$ 5,834	$ 35,289	$ 41,124
Total 2008-09	**$ 209,410**	**$ 429,458**	**$ 638,868**
Category	**2009-10 PS**	**2009-10 Bill 11**	**2009-10 Total**
Community	$ 20,337	$ 57,094	$ 77,431
Individual	$ 51,827	$ 199,038	$ 250,865
First Nations	$ 38,840	$ 174,859	$ 213,699
Total 2009-10	**$ 111,004**	**$ 430,992**	**$ 541,996**
Category	**TOTAL SPENDING FROM 2005-06 TO 2009-10 PS**	**Bill 11**	**Total**
Community	$ 327,968	$ 444,462	$ 772,430
Individual	$ 266,400	$ 452,639	$ 719,039
First Nations	$ 64,678	$ 353,555	$ 418,232
Grand Total All	**$ 659,045**	**$ 1,250,656**	**$ 1,909,702**

Notes:

1. Cost includes all work undertaken during the fiscal year. Participants noted below are only those that have all LIEEP program recommendations completed and a "post-retrofit E" ecoENERGY evaluations performed. In many homes some upgrades were performed, but not all work was completed.
2. The negative amount shown for 2007/08 is due to costs being reconciled related to recorded costs in the previous year being too high.

The following table provides the participation for electric heated homes in the Lower Income Energy Efficiency Program. Participation is defined as those homes that have completed all the LIEEP program recommendations and completed an ecoENERGY E evaluation (or comparable verification).

Category	Participants for Electric Heated Homes				
	2006-07 Total	2007-08 Total	2008-09 Total	2009-10 Total	2006-07 to 2008-09 TOTAL
Community	27	84	95	93	**206**
Individual	0	0	2	18	**2**
First Nations[1]	0	0	0	30	**0**
Grand Total All	**27**	**84**	**97**	**141**	**208**

NOTES:

1. There were 101 homes retrofitted in Island Lake however these homes haven't been recorded yet as the verification has not been undertaken yet.

60

PUB/MH I-111

Subject: **Tab 9: Demand Side Management**
Reference: **Appendix 9.1 , 2009 Power Smart Plan, Page 56-59- LIEEP**

b) Please provide details by measure on the forecasted spending on Electric LIEEP for the years 2009/10 and 2010/11.

ANSWER:

The following table provides details by measure on the forecast spending related to the Electric LIEEP during the years 2009/10 and 2010/11.

Forecasted Spending for Electric LIEEP - Power Smart Plan

Spending by Measure	Costs		
	2009/10	20010/11	Total
Power Smart			
Basic Energy Efficiency Items & Draft Proofing	$ 14,148	$ 14,855	$ 29,003
Insulation - Attic	$ 222,694	$ 267,243	$ 489,936
Insulation - Basement/Crawl	$ 99,713	$ 123,644	$ 223,357
Insulation - Wall	$ 143,898	$ 172,480	$ 316,378
Fridges	$ -	$ -	$ -
Total Incentives	**$ 480,452**	**$ 578,222**	**$ 1,058,674**
Total Administration	**$ 170,453**	**$ 177,742**	**$ 348,195**
Total Power Smart	**$ 649,966**	**$ 755,073**	**$ 1,405,039**
AEF			
Basic Energy Efficiency Items & Draft Proofing	$ 187,158	$ 208,815	$ 395,974
Insulation - Attic	$ 153,544	$ 173,635	$ 327,179
Insulation - Basement/Crawl	$ 1,322,788	$ 1,515,552	$ 2,838,341
Insulation - Wall	$ 192,482	$ 210,364	$ 402,846
Fridges	$ 467,611	$ 494,122	$ 961,733
Total Incentives	**$ 2,323,584**	**$ 2,602,488**	**$ 4,926,072**
Total Administration	**$ 892,272**	**$ 892,272**	**$ 1,784,544**
Total AEF	**$ 3,215,856**	**$ 3,494,760**	**$ 6,710,616**
Total Power Smart & AEF	**$ 3,865,821**	**$ 4,249,833**	**$ 8,115,655**

PUB/MH I-111

Subject: **Tab 9: Demand Side Management**
Reference: **Appendix 9.1 , 2009 Power Smart Plan, Page 56-59- LIEEP**

c) **Please provide a full description of the efforts currently being undertaken and delivered under the LIEEP on First Nations Communities.**

ANSWER:

Manitoba Hydro uses a dedicated team and partnership approach to pursue opportunities on First Nation Communities. Through this approach, Manitoba Hydro works with the community and assists in developing plans for pursuing energy efficient opportunities.

The following describes the general approach taken with each community:

- Manitoba Hydro staff first meet with the First Nation community and during this first meeting, the First Nations community is informed and educated on the Corporation's LIEEP;
- Manitoba Hydro's staff then work with the First Nation Community to select an initial group of ten homes to be retrofitted;
- Manitoba Hydro's staff arranges for home audits to be performed;
- Manitoba Hydro works with the community to secure the eligible material required for retrofitting the ten homes;
- Manitoba Hydro provides the First Nation Community with training, as required;
- the First Nation Community install the retrofit measures utilizing First Nation resources;
- Manitoba Hydro assists the First Nation Community in obtaining any eligible funds available through the Federal Government's ecoENERGY Grant program where applicable; and

- Upon completion of the initial 10 homes, a plan is developed to up-grade additional eligible housing within the community.

The following describes the current status with activities involving First Nation Communities:

Brochet: Plans are in place to visit the community in the spring

Crane River First Nation: 10 homes were identified in the community and work has been completed. Upon completion of the work a community presentation was conducted regarding moisture problems, heat recovery ventilator operation/maintenance, and basic energy efficiency measures such as insulated pipe wrap. Manitoba Hydro is working with the community to identify another 10 homes that might qualify for the program.

Cross Lake First Nation: Homes have been identified in the community, training has been provided by Manitoba Hydro and work currently has been completed on 16 homes. Manitoba Hydro is working with the community to identify additional homes that might qualify for the program.

Ebb & Flow First Nation: 10 homes have been identified in the community and work has been completed. Manitoba Hydro is working with the community to identify an additional 10 homes that might qualify for the program.

Fisher River First Nation: Homes have been identified in the community and Manitoba Hydro has provided training. The community has begun doing work on the homes and is near completion.

Island Lake First Nation: Manitoba Hydro has provided energy efficient materials to retrofit 101 homes in the community. Materials were shipped to the communities in March 2007. Manitoba Hydro has provided on-site training for the community. The community has indicated that all material has been used and verification of the work, numbers of houses completed and potential savings is taking place.

Lac Brochet First Nation: Homes have been identified in the community and Manitoba Hydro is working with the community to put a plan in place to do the work.

Lake Manitoba First Nation: Homes have been identified in the community and Manitoba Hydro is working with the community to put a plan in place to do the work.

Moose Lake First Nation: Homes have been identified in the community and Manitoba Hydro is working with the community to put a plan in place to do the work.

Nelson House First Nation: Discussions have begun with the community with a visit to the community scheduled for the near future

Peguis First Nation: 10 homes have been indentified in the community and work has been completed. Manitoba Hydro is working with the community to identify additional homes that might qualify for the program.

Pine Creek First Nation: Homes have been identified in the community and Manitoba Hydro is working with the community to put a plan in place to do the work.

Pukatawagan First Nation: Homes have been identified in the community and Manitoba Hydro is working with the community to put a plan in place to do the work.

Opaskwayak Cree Nation: Homes have been identified in the community and Manitoba Hydro is working with the community to put a plan in place to do the work.

Sagkeeng First Nation: Homes have been identified in the community and Manitoba Hydro is working with the community to put a plan in place to do the work.

Shamattawa First Nation: Homes have been identified in the community and Manitoba Hydro is working with the community to put a plan in place to do the work.

South Indian Lake First Nation: Homes have been identified in the community and Manitoba Hydro is working with the community to put a plan in place to do the work.

Tadoule Lake: Plans are in place to visit the community in the spring

67

67

PUB/MH II-104

Subject: **Tab 9: Demand Side Management**
Reference: **PUB/MH I-111 (b)**

a) **Please provide a comparison of the actual 2009/10 spending with the forecasted 2009/10 spending for Electric LIEEP by measure and explain major differences.**

ANSWER:

The following table provides the 2009/10 spending and a comparison to the 2009/10 budget. The variance is primarily due to the over estimate on participation. The budget amount for Basic Energy Efficiency Items was also corrected. In Manitoba Hydro's response to PUB/MH I-111(b), the amount of $14,148 was incorrectly entered into the table as the amount is $13,208.

LIEEP Actual Spend vs Budget - Electric			
SPENDING BY MEASURE	**ELECTRIC BUDGET**	**ELECTRIC ACTUAL SPEND**	**VARIANCE ACTUAL VS BUDGET**
		2009/10	
Participation	**803**	**141**	**662**
Power Smart			
Basic Energy Efficiency Items & Draft Proofing	$ 13,208	$ 3,378	$ 9,830
Insulation - Attic	$ 222,694	$ 37,090	$ 185,604
Insulation - Basement/Crawl	$ 99,713	$ 16,181	$ 83,532
Insulation - Wall	$ 143,898	$ 2,594	$ 141,304
Fridges/Furnace& Boiler	$ -	$ -	$ -
Total Incentives	**$ 479,512**	**$ 59,242**	$ 420,270
Total Administration	**$ 170,453**	**$ 51,762**	$ 118,691
			$ -
Total Power Smart Electric	**$ 649,965**	**$ 111,004**	**$ 538,961**

67

SPENDING BY MEASURE	ELECTRIC BUDGET	ELECTRIC ACTUAL SPEND		
Participation	**803**	**141**		**662**
AEF				
Basic Energy Efficiency Items & Draft Proofing	$ 187,158	$ 7,830		$ 179,329
Insulation - Attic	$ 153,544	$ 3,367		$ 150,177
Insulation - Basement/Crawl	$ 1,322,788	$ 86,947		$ 1,235,841
Insulation - Wall	$ 192,482	$ 3,795		$ 188,688
Fridges	$ 467,611	$ -		$ 467,611
Total Incentives	**$ 2,323,584**	**$ 101,938**		$ 2,221,645
Total Administration	$ 892,272	$ 329,054		$ 563,218
Total AEF Electric	$ 3,215,856	$ 430,992		$ 2,784,864
	$ -			$ -
Grand Total PS and AEF Electric	$ 3,865,821	$ 541,996		$ 3,323,824

PUB/MH II-104

Subject: **Tab 9: Demand Side Management**
Reference: **PUB/MH I-111 (b)**

b) **Please provide a detailed breakdown, including overheads, of the forecasted administration costs for the LIEEP for 2009/10, 2010/11 and 2011/12 that are funded by Power Smart and by the AEF.**

ANSWER:

Forecast Budget

Spending by Measure	Electric Costs	Electric Costs	Electric Costs
	2009/10	20010/11	Total
Power Smart			
Administration:			
ecoENERGY Audit	$ 80,300	$ 96,300	$ 176,600
Labour	$ 57,700	$ 52,200	$ 109,900
Overhead	$ 15,600	$ 14,100	$ 29,700
Other *	$ 16,900	$ 15,200	$ 32,100
Total Administration	**$ 170,500**	**$ 177,800**	**$ 348,300**
AEF			
Administration:			
ecoENERGY Audit	$ 185,300	$ 209,200	$ 394,500
Labour	$ 238,100	$ 219,500	$ 457,600
Overhead	$ 64,400	$ 59,300	$ 123,700
Other *	$ 404,500	$ 404,300	$ 808,800
Total Administration	**$ 892,300**	**$ 892,300**	**$ 1,784,600**

* includes contingency, outreach & support costs, marketing and training

PUB/MH II-106

Subject: **Tab 9: Demand Side Management**
Reference: **PUB/MH I-113 (a) AEF**

a) **Please provide a detailed breakdown by initiative (similar to the response to PUB/MH 111(b)) of the forecast $8.5 Million spending in 2009/10 and $9.0 million in 2010/11 on the Lower Income Program from the AEF including administrative, energy audits and other (for both natural gas and electric operations)**

ANSWER:

Forecast Budget

Spending by Measure	**Electric Costs**	**Electric Costs**	**Electric Costs**
	2009/10	**20010/11**	**Total**
AEF			
Incentives:			
Basic Energy Efficiency Items & Draft Proofing	$ 187,200	$ 208,800	$ 396,000
Insulation - Attic	$ 153,500	$ 173,600	$ 327,100
Insulation - Basement/Crawl	$ 1,322,800	$ 1,515,600	$ 2,838,400
Insulation - Wall	$ 192,500	$ 210,400	$ 402,900
Fridges	$ 467,600	$ 494,100	$ 961,700
Total Incentives	**$ 2,323,600**	**$ 2,602,500**	**$ 4,926,100**
Administration:			
ecoENERGY Audit	$ 185,300	$ 209,200	$ 394,500
Labour	$ 238,100	$ 219,500	$ 457,600
Overhead	$ 64,400	$ 59,300	$ 123,700
Other*	$ 404,500	$ 404,300	$ 808,800
Total Administration	**$ 892,300**	**$ 892,300**	**$ 1,784,600**
Total AEF	**$ 3,215,900**	**$ 3,494,800**	**$ 6,710,700**

67

Forecast Budget

Spending by Measure	Gas Costs	Gas Costs	Gas Costs
	2009/10	20010/11	Total
AEF			
Incentives:			
Basic Energy Efficiency Items & Draft Proofing	$ 309,500	$ 320,000	$ 629,500
Insulation - Attic	$ 285,800	$ 294,300	$ 580,100
Insulation - Basement/Crawl	$ 2,515,000	$ 2,568,900	$ 5,083,900
Insulation - Wall	$ 338,600	$ 356,600	$ 695,200
Fridges	$ -	$ -	$ -
Total Incentives	**$ 3,449,000**	**$ 3,539,800**	**$ 6,988,800**
Administration:			
ecoENERGY Audit	$ 229,400	$ 316,200	$ 545,600
Labour	$ 294,800	$ 341,800	$ 636,600
Overhead	$ 79,700	$ 92,400	$ 172,100
Other *	$ 629,200	$ 625,700	$ 1,254,900
Total Administration	**$ 1,233,100**	**$ 1,376,100**	**$ 2,609,200**
Total AEF	**$ 4,682,100**	**$ 4,915,900**	**$ 9,598,000**

Forecasted Budget

Spending by Measure	Other Fuels Costs	Other Fuels Costs	Other Fuels Costs
	2009/10	20010/11	Total
AEF			
Basic Energy Efficiency Items & Draft Proofing	$ 30,000	$ 29,800	$ 59,800
Insulation - Attic	$ 78,400	$ 75,600	$ 154,000
Insulation - Basement/Crawl	$ 288,200	$ 281,000	$ 569,200
Insulation - Wall	$ 66,700	$ 65,600	$ 132,300
Fridges	$ -	$ -	$ -
Total Incentives	**$ 463,100**	**$ 452,000**	**$ 915,100**
			$ -
Administration:			$ -
ecoENERGY Audit	$ 53,600	$ 52,400	$ 106,000
Labour	$ 49,600	$ 48,500	$ 98,100
Overhead	$ 13,400	$ 13,100	$ 26,500
Other *	$ 72,400	$ 67,600	$ 140,000
Total Administration	$ 189,000	$ 181,600	$ 370,600
Total AEF	**$ 652,100**	**$ 633,600**	**$ 1,285,700**

67

Total Forecast Budget

Spending by Measure	TOTAL 2009/10	TOTAL 20010/11	TOTAL Total
AEF			
Basic Energy Efficiency Items & Draft Proofing	$ 526,700	$ 558,600	$ 1,085,300
Insulation - Attic	$ 517,700	$ 543,500	$ 1,061,200
Insulation - Basement/Crawl	$ 4,126,000	$ 4,365,500	$ 8,491,500
Insulation - Wall	$ 597,800	$ 632,600	$ 1,230,400
Fridges	$ 467,600	$ 494,100	$ 961,700
Total Incentives	**$ 6,235,700**	**$ 6,594,300**	**$ 12,830,000**
	$ -	$ -	$ -
Administration:	$ -	$ -	$ -
ecoENERGY Audit	$ 468,300	$ 577,800	$ 1,046,100
Labour	$ 582,500	$ 609,800	$ 1,192,300
Overhead	$ 157,500	$ 164,800	$ 322,300
Other*	$ 1,106,000	$ 1,097,600	$ 2,203,600
Total Administration	$ 2,314,300	$ 2,450,000	$ 4,764,300
Total AEF	**$ 8,550,000**	**$ 9,044,300**	**$ 17,594,300**

* includes contingency, outreach & support costs, marketing and training

67

PUB/MH II-98

Subject: **Tab 9: Demand Side Management**
Reference: **PUB/MH I-110 (c) DSM LIEEP**

Please provide a comparison of the actual participation for 2009/10 with the forecasted participation for electric homes and explain any differences.

ANSWER:

The forecast and actual participation for 2009/10 is provided in the following table.

	Forecasted Participation				Actual Participation			
	2009-10				2009-10			
Category	Gas	Electric	Other	Total	Gas	Electric	Other	Total
Homeowner	1,128	608	119	1,855	357	23	3	383
Tenant	513	196	55	764	233	96	-	329
Total	1,641	804	174	2,619	590	119	3	712

The actual participation was lower than forecast due to varying factors including the underestimate of time required to establish the infrastructure (e.g. agreements with contractors, internal processes, etc.) required to implement the program and the underestimate of time required to deal with competing demands placed on staff dedicated to the lower income program.

68

PUB/MH I-21

Subject: **Tab 4: Financial Results & Forecast**
Reference: **2009 Annual Report, Page 116, Note 20**

a) **Please provide an update on the Affordable Energy Fund (AEF) including the projected use of the funds, by program and a detailed description of the programs.**

ANSWER:

Projects to be supported through the Affordable Energy Fund include:

- **Low-Income/Community-Based Initiative: $19 Million**
  This initiative targets low-income Manitobans, including Aboriginals and seniors. These funds would be incremental to incentives that are available through Manitoba Hydro's Power Smart programs.

- **Geothermal Support Program: $6 Million**
  This initiative supports the application of geothermal technology.

- **Community Energy Development: $8 Million**
  This project, currently in the planning stage, will encourage the development of community-based energy projects in Manitoba. The purpose of the pilot project is to identify the issues and potential solutions associated with developing small, innovative renewable energy projects in Manitoba. This information will be used to determine whether and how similar projects might be pursued throughout the province.

- **Community Support and Outreach: $750 000**
  This initiative involves Manitoba Hydro funding additional resources for the purpose of encouraging rural and northern customers to participate in Power Smart initiatives. In addition, a lower interest rate loan applicable to First Nation Communities is subsidized through this category.

- **Oil and Propane-Heated Residential Homes: $250 000**
  This initiative extends the eligibility under the residential Power Smart Insulation and New Home programs to include homes currently heated by a source other than electricity and natural gas.

- **Special Projects: $2.4 Million (including accrued fund interest as of January 31, 2010)**

  - ***Residential Energy Assessment Service - $545 000***
    This initiative funds the incremental costs associated with delivering Manitoba Hydro's In-home Energy Assessment service under the Federal ecoEnergy Retrofit program to rural and northern Manitobans.

  - ***Oil and Propane Furnace Replacement - $150 000***
    This initiative targets the replacement of oil and propane furnaces with either an electric or high efficient natural gas furnace. The program provides a rebate of $245 to participating customers. Low Income customers will be eligible to convert at a cost of $19 per month for five years.

  - ***Residential Solar Water Heating Program - $305 000***
    This initiative supports the application of solar domestic hot water pre-heating systems and the development of the local solar industry.

  - ***Power Smart Residential Loan - Up to $1.15 Million***
    This initiative will reduce the interest rate for the Power Smart Residential Loan from the cost recovery rate to a rate of 4.9%.

PUB/MH I-113

Subject: **Tab 9: Demand Side Management**
Reference: **Affordable Energy Fund**

a) **Please provide a table which includes actual and forecast spending by program since the inception of the AEF**

ANSWER:

	Actual Expenditures (millions)			Forecast Expenditures (millions)						
Initiative	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16
Lower Income Program	0.3	0.2	0.9	8.5	9.0	0.0	0.0	0.0	0.0	0.0
Geothermal Support	0.6	0.3	0.1	0.4	0.5	1.4	1.4	0.4	0.3	0.1
Community Energy Development	0.0	0.0	0.0	0.2	1.5	1.5	1.5	1.5	1.8	0.0
Community Support and Outreach	0.0	0.0	0.0	0.1	0.2	0.2	0.2	0.2	0.0	0.0
Oil and Propane Heated Homes	0.0	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0
Special Projects										
Residential ecoEnergy Audits	0.0	0.1	0.2	0.1	0.1	0.0	0.0	0.0	0.0	0.0
Oil and Propane Furnace Replacement	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Solar Water Heaters	0.0	0.0	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0
Residential Loan	0.0	0.0	0.0	0.6	0.2	0.1	0.1	0.0	0.0	0.0
ANNUAL EXPENDITURES	$0.9	$0.6	$1.4	$10.1	$11.7	$3.2	$3.2	$2.1	$2.1	$0.1

	Forecast Expenditures (millions)									
Initiative	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	Total
Lower Income Program	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	19.0
Geothermal Support	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0	6.0
Community Energy Development	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	8.0
Community Support and Outreach	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.8
Oil and Propane Heated Homes	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3
Special Projects										
Residential ecoEnergy Audits	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.5
Oil and Propane Furnace Replacement	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2
Solar Water Heaters	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3
Residential Loan	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.2
ANNUAL EXPENDITURES	$0.1	$0.1	$0.1	$0.1	$0.1	$0.0	$0.0	$0.0	$0.0	$36.2

PUB/MH I-113

Subject: **Tab 9: Demand Side Management**
Reference: **Affordable Energy Fund**

b) Please detailed expenditures by year since the establishment of the AEF on electric DSM programs and forecasted to 2024/25

ANSWER:

The following table outlines the actual and planned Affordable Energy Fund expenditures that support all or partial electric energy efficiency programs. Manitoba Hydro does not allocate the Affordable Energy Fund budget to electric and natural gas, rather the Affordable Energy Fund supports the program and both electric and natural gas heated customers can participate. The table below outlines the total funding for the initiatives.

	Actual Expenditures (millions)			Forecast Expenditures (millions)						
Initiative	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16
Lower Income Program	0.3	0.2	0.9	8.5	9.0	0.0	0.0	0.0	0.0	0.0
Geothermal Support	0.6	0.3	0.1	0.4	0.5	1.4	1.4	0.4	0.3	0.1
Community Support and Outreach	0.0	0.0	0.0	0.1	0.2	0.2	0.2	0.2	0.0	0.0
Special Projects										
Residential ecoEnergy Audits	0.0	0.1	0.2	0.1	0.1	0.0	0.0	0.0	0.0	0.0
Solar Water Heaters	0.0	0.0	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0
Residential Loan	0.0	0.0	0.0	0.6	0.2	0.1	0.1	0.0	0.0	0.0
ANNUAL EXPENDITURES	$0.9	$0.6	$1.4	$9.8	$10.1	$1.7	$1.7	$0.6	$0.3	$0.1

	Forecast Expenditures (millions)									
Initiative	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	Total
Lower Income Program	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	19.0
Geothermal Support	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0	6.0
Community Support and Outreach	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.8
Special Projects										
Residential ecoEnergy Audits	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.5
Solar Water Heaters	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3
Residential Loan	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.2
ANNUAL EXPENDITURES	$0.1	$0.1	$0.1	$0.1	$0.1	$0.0	$0.0	$0.0	$0.0	$27.8

69

PUB/MH II-63

Subject: **Tab 6: Capital Expenditures**
Reference: **PUB/MH I-59 (a)/20-Year IFF 08-1 Assumptions Rationale for West Side Bipole III**

a) **Please confirm that despite higher costs and longer time frames for approvals and construction, MH sees a pressing need to proceed with a West Side Bipole III location.**

ANSWER:

The existing Bipole I and Bipole II, which carry about 75% of Manitoba Hydro's generation, are vulnerable to catastrophic weather related events. Due to the enormous negative consequences to the Province from a catastrophic failure of the existing bipoles, Manitoba Hydro has recommended Bipole III for reliability in order to be able to continue to serve Manitoba load if a catastrophic event results in the loss of Bipoles I & II. To minimize the exposure to this risk, Bipole III should be placed in service as soon as possible. The expected in-service date is the fall of 2017.

It should be noted that while the longer west side route has a higher cost, it is unknown as to whether the environmental assessment process for a west side route will require more time than an east side route. The time required for government environmental approvals is independent of the route, and is not determined by Manitoba Hydro.

61

PUB/MH II-90

Subject: **Tab 8: Energy Supply**
Reference: **PUB/MH I-60 Bipole III, 2007/12/07 PUB/MH I-4 (f)**

c) Please confirm that Bipole III is typically expected to function at the 2,000 MW level and after 2024, transmit about 1,200 GWh of energy/month on average or up to about 1,500 GWh/month (maximum).

ANSWER:

Bipole III is to be rated to allow a 2000 MW power level leaving the northern converter.

Theoretically, in a 31 day month, up to 1,488 GW.h of energy (before consideration of losses) could be transmitted with 2,000 MW of transfer capability, assuming continuous loading to the maximum transfer capability for the entire period. Such continuous loading to the maximum transfer capability is not the normal operating practice, does not allow for following the Manitoba load shape and does not allow for any maintenance work.

The energy transmitted per month on average is estimated to be about 1000 GW.h after 2024 with Keeyask and Conawapa in service.

6P

PUB/MH II-91

Subject: **Tab 8: Energy Supply**
Reference: **PUB/MH I-14 (f) HVDC Functional Usage**

a) **Please confirm or amend (and explain) the following estimates of typical or average functional usage of the HVDC system.**

Bipoles I and II						
Serve G.S.@	**MW**	**Dependable (GWh)**	**Median (GWh)**	**Maximum (GWh)**	**Maximum HVDC Output**	
Kettle	**1,220**	**4,750**	**7,010**	**8,960**	**|- Bipole I**	**13,300 GWh**
Long Spruce	**1,010**	**3,890**	**5,970**	**7,830**	**|**	
Limestone	**1,340**	**5,140**	**7,500**	**9,900**	**|- Bipole II**	**13,400 GWh**
Totals	**3,570**	**13,780**	**20,480**	**26,690**		**26,700 GWh**

After Bipole III						
Serve G.S. @	**MW**	**Dependable (GWh)**	**Median (GWh)**	**Maximum (GWh)**	**Maximum HVDC Output**	
Keeyask	**600**	**2,880**	**4,480**	**4,740**	**|- Bipole I**	**13,700 GWh**
Kettle	**1,220**	**4,750**	**7,010**	**8,960**		
Long Spruce	**1,010**	**3,890**	**5,970**	**7,830**	**|- Bipole II**	**13,700 GWh**
Limestone	**1,340**	**5,140**	**7,500**	**9,900**	**|**	
Conawapa	**1,300**	**4,600**	**7,050**	**9,760**	**|- Bipole III**	**13,800 GWh**
Totals	**5,270**	**21,260**	**32,010**	**41,190**		**41,200 GWh**

ANSWER:

The capacity and energy available from Limestone will be reduced when Conawapa is constructed, as Conawapa forebay will raise the water level at Limestone tailrace. Normally the reduction at Limestone is reflected in the capacity of Conawapa as "Net Addition".

The maximum energy capability of the Bipoles is estimated assuming that 500 MW is reserved as spare transmission, shared between the available bipoles. The maximum energy transfer capability of the Bipoles is calculated by adjusting the Bipoles for the prorated share of the 500 MW reserve, and fully loading the adjusted Bipoles for all hours of the year.

The capacities quoted reflect maximum capability in January, without reserves.

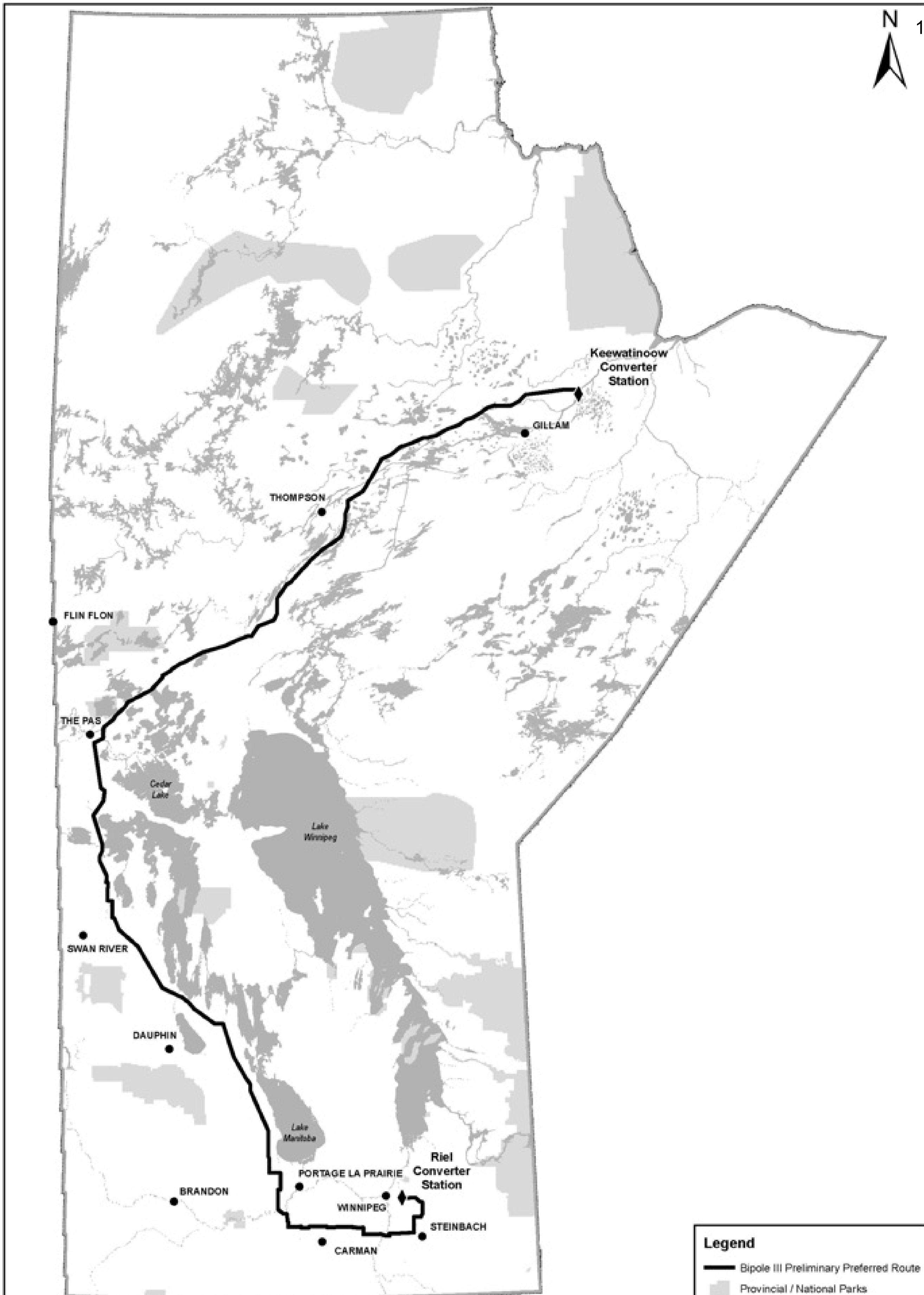
69

The capability of generating stations that was used in preparing the 2009/10 power resource plan is as follows:

Generating Station.	MW	Dependable (GWh)	Median (GWh)	Maximum (GWh)	Maximum HVDC Output		
Kettle	1,220	5,180	7,130	8,770	Bipole I	14,150 GWh	1,854 MW
Long Spruce	1,007	4,240	6,080	7,665	Bipole II	15,250 GWh	2,000 MW
Limestone	1,335	5,610	7,630	9,695			
Totals	3,562	15,030	20,840	26,130		29,400 GWh	3,854 MW

Generating Station	MW	Dependable (GWh)	Median (GWh)	Maximum (GWh)	Maximum HVDC Output		
Keeyask	630	2,900	4,360	5,260	Bipole I	14,900 GWh	1,854 MW
Kettle	1,220	5,180	7,130	8,770	Bipole II	16,000 GWh	2,000 MW
Long Spruce	1,007	4,240	6,080	7,665	Bipole III	16,000 GWh	2,000 MW
Limestone	1,335	5,610	7,630	9,695			
Conawapa*	1,300	4,550	7,820	10,740			
Totals	5,492	22,480	33,020	42,130		46,900 GWh	5,854 MW

*Conawapa values are the "net addition". Conawapa Generation is adjusted to reflect the losses at Limestone.



Manitoba Hydro

Coordinate System:UTM Zone 14N, NAD83
Data Source: MBHydro, MMM Group
Date Created: July 08, 2010

Bipole III Preliminary Preferred Route

70

70.

PUB/MH II-90

Subject: **Tab 8: Energy Supply**
Reference: **PUB/MH I-60 Bipole III, 2007/12/07 PUB/MH I-4 (f)**

b) **Please provide the anticipated annual interest/depreciation/OM&A costs associated with Bipole III after in-service.**

ANSWER:

Please see the attached schedule.

70

BIPOLE III
COMPONENTS INCLUDED IN 20 YEAR OUTLOOK
(In Millions of Dollars)

For the year ended March 31	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Operating and Administrative	-	-	-	-	-	-	-	-	13	13	13
Finance Expense	-	-	-	-	-	-	-	-	2	158	153
Depreciation and Amortization	-	-	-	-	-	-	-	-	19	46	46

BIPOLE III
COMPONENTS INCLUDED IN 20 YEAR OUTLOOK
(In Millions of Dollars)

For the year ended March 31	2021	2022	2023	2024	2025	2026	2027	2028	2029
Operating and Administrative	13	14	14	14	14	15	15	15	16
Finance Expense	149	145	140	136	132	129	125	122	118
Depreciation and Amortization	46	46	46	46	46	46	46	46	46

Bipole III - Western Routed HVdc T/L and 2000MW Converters
Calculation of CPJ Addendum Amounts based on the Revised Estimate (Summer 2010)
(in thousands of dollars)

Prepared by: Transmission BU

IM Node WBS	COMPLEX DESCRIPTION FOR CEF Project Description	REVISED ESTIMATE Summer 2010 Total Net (In-service Cost)	Increase (Decrease) vs. APPROVED BUDGET [Amount to explain under each CPJ Addendum] Base *	Contingency	Int. & Esc	Total Net (In-service Cost)
1.5.2.1.1.1	BIPOLE III - LICENSING & PROPERTIES	187,732	37,381	17,278	9,523	64,182
P:04221	Licensing & Environmental Assessment	117,490	2,544	13,312	8,766	24,622
P:14363	Property - Riel Converter Station	18,800	18,742	-	57	18,800
P:14518	Property - BPIII Transmission Line	34,948	5,303	3,966	(5,003)	4,266
P:15533	Property - Keewatinoow Converter Station	63	60	-	3	63
P:15537	Property - Keewatinoow Collector Lines	536	522	-	14	536
P:15696	Property - Keewatinoow Electrode Line & Station	201	148	-	52	201
P:15697	Property - Riel Electrode Line & Station	15,696	10,061	-	5,635	15,696
1.5.2.1.2.1	BIPOLE III - TRANSMISSION LINE	1,209,958	107,774	116,001	27,809	251,584
P:10155	Western Route 500kV Transmission Line	1,206,127	106,691	116,001	25,647	248,339
P:04218	Eastern Route 500kV T/L (sunk costs)	3,831	1,084	-	2,162	3,246
1.5.2.1.3.1	KEEWATINOOW CONVERTER STATION	947,984	152,719	218,650	110,325	481,695
P:15540	Keewatinoow Converter Station	938,346	152,474	217,000	108,264	477,738
P:15542	Keewatinoow Electrode Line	9,638	245	1,650	2,061	3,956
1.5.2.1.4.1	KEEWATINOOW AC COLLECTOR SYSTEM	294,214	107,317	44,403	61,589	213,309
P:15535	Keewatinoow C.S.-Construction Power	43,458	23,381	5,451	14,626	43,458
P:15536	Keewatinoow 230kV Collector Lines	112,588	30,415	8,952	21,497	60,864
P:15544	Keewatinoow 230kV AC Switchyard	138,168	53,520	30,000	25,467	108,987
1.5.2.1.5.1	RIEL CONVERTER STATION	1,467,169	333,361	292,150	222,940	848,452
P:15541	Riel Converter Station	1,219,636	219,344	266,000	147,357	632,700
P:14364	Riel C.S. & 230kV AC Switchyard Site Development	238,212	111,942	25,000	73,798	210,740
P:15534	Riel R49R T/L Sectionalization	2,493	1,955	-	538	2,493
P:15543	Riel Electrode Line	6,828	121	1,150	1,248	2,519
TOTAL for BIPOLE III		4,107,057	738,553	688,482	432,187	1,859,222

Notes:
- Scope for Bipole III does not include Riel Sectionalization, Riel 230kV Outlet Lines or Protecting for a 2500MW Option
- Revised Estimate Total Net figures include interest and escalation to the 2017 in-service as calculated for that year's CERs.

N:\Riel BPIII Proj Mgmt Section\BP III Complex\Estimates\2010\Estimate History by WBS.xls

2010.10.05

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PUB/MH I-197

Reference: Tab 14, 13.4 (3) 20 year - Year Financial Outlook Page 3 – Major Capital

Please provide the incremental revenue requirement impacts for the first year beyond in-service for Bipole III , Keeyask G.S. and Conawapa G.S.

ANSWER:

The incremental revenue requirement impacts are estimated below for the first full year of operation of each of the facilities above.

Revenue is estimated based upon Keeyask and Conawapa generation and Bipole III line loss savings at calculated average export prices (per PUB/MH I-45(b)). Finance expense is estimated based upon the incremental revenue net of expenses plus the initial capital outlay of the project at the projected Manitoba Hydro Canadian long term debt rate.

The incremental revenue requirements estimated for one year would not imply that rate increases are required in those years. Over the long term, generation benefits offset initial capitalization costs (see the Alternative Development Sequence in Appendix 15). Bipole III is a non-discretionary facility required for reliability purposes and related benefits in addition to the line loss savings have not been quantified for the purposes of estimating the incremental revenue requirements. Bipole III allows for the export benefits derived from Keeyask and Conawapa.

		Millions of $		
		Bipole III 2019	**Keeyask** 2021	**Conawapa** 2025
Revenue	$	26	$ 294	$ 543
Expenses				
OM&A, Depreciation, Capital Tax and Water Rentals		68	101	158
Finance expense		158	283	412
Total Expenses		225	383	570
Estimated Incremental Revenue Requirement	$	199	$ 89	$ 27