Exhibit PUB #

Volume 1 – Board Counsel's Book of Documents

Manitoba Hydro 2012/13 and 2013/14 GRA

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MANITOBA HYDRO
2012/13 & 2013/14 GENERAL RATE APPLICATION

VOLUME I

LETTER OF APPLICATION

IN THE MATTER OF: *The Crown Corporations Public Review & Accountability Act* (Manitoba)

IN THE MATTER OF: An Application by Manitoba Hydro for an Order of the Public Utilities Board Approving Increases to Electricity Rates

TO: The Executive Director of the
Public Utilities Board of Manitoba
Winnipeg, Manitoba

Manitoba Hydro hereby applies to the Public Utilities Board of Manitoba ("PUB") for an Order pursuant to *The Crown Corporations Public Review & Accountability Act* for the following:

a) Approval, on an interim basis, of rate schedules incorporating an across the board 2.5% rate increase on currently billed rates, effective September 1, 2012, sufficient to generate additional revenues of $20 million in 2012/13;

b) Approval of a further 3.5% increase in overall revenue effective April 1, 2013, sufficient to generate additional revenues of ~~$48~~ $47 (PUB/MH I-53) million in 2013/14 (with rate schedules to follow subsequent to Manitoba Hydro-Electric Board approval in August 2012);

c) Approval to maintain in base rates the rates approved by the PUB in Orders 30/10 and 40/11, and include in current year revenues, the revenues previously billed and collected, which have been accumulated in the deferral account pertaining to rates implemented April 1, 2010;

d) Final approval of Orders 32/12 and 34/12 approving interim rates effective April 1, 2012, and final approval of any other interim rate Orders issued subsequent to the filing of the Application and prior to conclusion of this proceeding;

e) Approval, on an interim basis, of rate schedules incorporating a 6.5% rate increase effective September 1, 2012 (consistent with previous and proposed rate increases for grid customers), for the full-cost portion of the rate applicable to general service and government customers in four remote communities served by diesel generation, sufficient to generate additional revenue of $0.2 million in 2012/13;

f) Confirmation that the Board accepts the rate approval process given proposed modifications to the Terms and Conditions of the Surplus Energy Program ("SEP"), as will be discussed in Tab 11 of this Application;

g) Confirmation that the Board accepts the rate approval process given proposed modifications to the Curtailable Rate Program ("CRP"), as will be discussed in Tab 11 of this Application;

h) Final approval of all SEP interim *ex parte* rate orders as will be set forth in Tab 11 of this Application, as well as any additional SEP *ex parte* rate orders issued subsequent to the filing of this Application and prior to the PUB's order in this matter;

i) Final approval of CRP *ex parte* Order 52/12 as well as any additional *ex parte* orders issued in respect of the CRP issued subsequent to the filing of this Application and prior to the PUB's order in this matter; and,

j) Final approval of diesel zone interim Orders (17/04, 46/04, 159/04, 176/06, 1/10, 134/10, 1/11 and 148/11), subject to confirmation that MKO has provided the parties to the agreement with the required affidavits from representatives of signatories to the agreement, as well as any additional diesel zone interim orders issued subsequent to the filing of this Application and prior to the PUB's order in this matter.

Manitoba Hydro intends to file Volume II of this Application by the end of June 2012, including materials on its electric load forecast, energy supply, proposed rates and customer impacts, and responses to a number of PUB directives. Communication related to this Application should be addressed to Manitoba Hydro in the following fashion:

Manitoba Hydro
Attention: Patti Ramage
22nd Floor, 360 Portage Avenue
Winnipeg, Manitoba
R3C 0G8

Telephone No. (204) 360-3946

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Fax No. (204) 360-6147
E-Mail: pjramage@hydro.mb.ca

DATED at Winnipeg, Manitoba this 15th day of June, 2012.

MANITOBA HYDRO

"ORIGINAL SIGNED
BY PATRICIA J. RAMAGE"

Per: ______________________
Patricia J. Ramage

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Manitoba Hydro

PO Box 815 • Winnipeg, Manitoba Canada • R3C 2P4
Street Location for DELIVERY: 22nd floor 360 Portage Ave
Telephone / N° de téléphone : (204) 360-3946 • Fax / N° de télécopieur : (204) 360-6147
pjramage@hydro.mb.ca

October 3, 2012

Mr. H. Singh
Executive Director
Public Utilities Board
400-330 Portage Avenue
Winnipeg, Manitoba
R3C 0C4

Dear Mr. Singh:

RE: Manitoba Hydro 2012/13 & 2013/14 General Rate Application- Proposed Rates Effective April 1, 2013

In its 2012/13 & 2013/14 General Rate Application, Manitoba Hydro is requesting approval of a 3.5% General Consumers' Revenue increase effective April 1, 2013. Manitoba Hydro is hereby amending its Application to also request Public Utilities Board of Manitoba ("PUB") approval to implement Time-of-Use ("TOU") Rates for the General Service Large customer class served at greater than 30kV, effective April 1, 2013, and is proposing to increase the demand ratchets for these customers from 25% to 50% of contract demand or 50% of the highest demand in the past 12 months.

This submission will form Appendix 10.11 of Tab 10 of the Application. A detailed Proof of Revenue, Rate Schedules and Bill Impacts for the proposed rates effective April 1, 2013 are enclosed as Appendices 10.12, 10.13 and 10.14.

Time-of-Use Rates

Manitoba Hydro is requesting approval to implement TOU rates for the General Service Large class served at greater than 30kV, effective April 1, 2013. Relative to the current rate structure, the proposed TOU energy rates are higher during the on-peak periods (Monday to Friday from 6:00 am to 10:00 pm excluding statutory holidays) and lower during the off-peak periods (all other hours). In order to design an appropriate on-peak energy price signal without increasing overall class revenue, it was necessary to reduce the prices for off-peak energy and demand. Consequently, the proposed demand charges are reduced by 50% relative to the current demand charges.

The introduction of a TOU rate enables Manitoba Hydro to provide more appropriate price signals to large energy users, providing a clearer indication of the value of energy to Manitoba Hydro, while maintaining revenue neutrality and preserving Manitoba's competitive industrial rate position relative to other provinces and states. Such a rate also partially addresses Manitoba Hydro's concerns about load growth by energy-intensive industries and the potential impact that such growth may have on profitable on-peak export sales through the creation of a rate structure that is representative of the pricing trends and behavior in the Midwestern Independent System Operator ("MISO") power market, particularly during the on-peak period.

The proposed TOU rates are reasonably correlated to the rates obtained from current firm export contracts in the on-peak period. Manitoba Hydro will periodically apply to adjust future TOU rates to continue sending a price signal that is comparable to anticipated firm export contracts that may be negotiated going forward.

Manitoba Hydro also proposes to change the ratchets used to determine the General Service Large class over 30kV minimum billing demand. Manitoba Hydro is contractually obligated to provide power up to a customer's contract demand. Manitoba Hydro is concerned that unused capacity, reserved by customers through their specified contract demand levels, may impede the Corporation's ability to serve new and/or expanding load with existing transmission infrastructure, resulting in potential costs for new infrastructure that would not be required if unused capacity was released. Manitoba Hydro's current General Service Large rate structure includes a minimum monthly billing demand charge that is defined as the highest of actual recorded demand, 25% of contract demand or 25% of the highest recorded demand in the past 12 months. The existing billing threshold provides minimal incentive for most large customers to reduce their contracted demand levels if significant contracted capacity remains unused.

Manitoba Hydro is proposing to change the definition of billing demand for the General Service Large over 30kV customers to the greatest of (in kVA):

- The highest measured on-peak demand in the month;
- 50% of the contract demand; or,
- 50% of the highest on-peak demand in the previous 12 months.

The intent of raising the ratchet percentages is to encourage customers to make efficient decisions regarding the transmission and sub-transmission resources that they wish to reserve.

April 1, 2013 Proposed Rates & Customer Impacts

Manitoba Hydro is proposing customer class-differentiated rate increases effective April 1, 2013, in recognition of revenue/cost coverage ratios ("RCCs") resulting from the updated Cost of Service Study.

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The proposed class-differentiated rate increases and respective RCCs before and after the recommended rate increases are as follows:

Customer Class	RCCs Before Rate Increase (%)	Recommended Rate Increases (%)	RCCs After Rate Increase (%)
Residential	99.2	3.5	99.1
General Service			
- Small Non-Demand	107.6	3.0	107.5
- Small Demand	103.7	3.4	103.7
- Medium	100.0	3.6	100.0
- Large 750V – 30 kV	93.3	4.5	94.1
- Large 30 kV – 100 kV	96.6	4.0	97.1
- Large > 100 kV	100.5	3.4	100.4
Area/Roadway Lighting	101.8	3.5	103.4

On a class basis, the increase in revenue for 2013/14 is as follows:

Customer Class	2013/14 Additional $ (millions)
Residential	$19.3
GS Small	$8.5
GS Medium	$6.5
GS Large	$12.7
A&R Lighting	$0.8
Misc. & DSM	($0.4)
Total GCR	$47.4

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The following is a brief summary of the changes proposed in rates for the major rate classes.

Residential

The monthly Basic Charge will remain the same at $6.85 per month. The total increase in class revenue will be derived solely from the Energy Charge, which will increase by 3.7% to 7.20 ¢/kWh.

Based on the proposed April 1, 2013 rates, residential customers will experience increases ranging from 2.7% to 3.7% depending on monthly consumption. For example, a typical residential customer without electric space heat using approximately 1,000 kWh per month will see an increase in their monthly bill of $2.60 or 3.4%. A residential customer with electric space heat, consuming an average of 2,000 kWh per month, will experience an increase of $5.20 per month or 3.6%.

General Service Small and Medium

No change in the Demand Charge is proposed for the General Service Small or Medium classes. The Basic Charge for General Service Small customers will increase 3.5%, while the Basic Charge for General Service Medium customers will remain unchanged. The proposed Energy Charge for the General Service Small and Medium classes will increase 2.9% for the first block, 4.7% for the second block and 6.0% for the run-off rate. The larger increase in the tail block rate is necessary given that no increase in the demand charge is being sought.

General Service Small customers will see increases ranging from 2.6% to 4.4% depending on monthly load factor. The overall class average increase for General Service Small is 3.2%, slightly lower than the overall General Consumers increase of 3.5% proposed for April 1, 2013.

General Service Medium customers will experience increases in the range of 2.5% to 4.4% depending on monthly load factor. The overall average increase for the General Service Medium customer class is 3.6%.

General Service Large

The rates being proposed effective April 1, 2013 are reflective of the differences in RCC ratios between the three General Service Large sub-classes. Large 750V-30 kV customers will see the largest increase at 4.5% due to their RCC being outside the zone of reasonableness. The overall proposed increase for the GS Large 30-100 kV sub-class is 4.0%, also due to their lower RCC. The GS Large >100 kV sub-class will see an average increase of 3.4%.

Large customers served at 750V-30kV will see increases in their monthly bill ranging from 3.1% to 5.3%. Bill impacts for the Large >30 kV customers will vary considerably with the introduction of TOU rates. Depending on load factor, seasonal and daily energy usage distribution some customers may experience bill decreases, others will experience increases. The Bill Comparisons provided in

Appendix 10.13 for these sub-classes are based on the overall class average distribution of energy between the four pricing periods and represent the extreme impacts for the four load factor categories shown. For the Large 30-100 kV sub-class, bill impacts will range from (14.2%) to 10.1%. For the Large >100 kV sub-class the impacts will range from (15.4%) to 6.6%. A few customers could experience bill increases greater than 10.1% due to the proposed contract ratchet provisions; these customers will have the opportunity to mitigate bill impacts by re-contracting.

Area and Roadway Lighting

The rate increase proposed for the Area and Roadway Lighting Class is identical to the overall proposed General Consumers' Revenue increase of 3.5%. For other classes, an increase in revenue leads to a similar increase in cost and little change in the RCC. For Area and Roadway Lighting, the RCC will change even in the case of an across-the-board increase due to the dedicated costs unique to the class, and the way rate increases are implemented in the PCOSS. Manitoba Hydro notes that the proposed class increase is appropriate because the higher RCC is still within the Zone of Reasonableness and Area and Roadway Lighting infrastructure is ageing and incremental investment will be required in the next decade to replace or upgrade facilities.

In conclusion, the proposed rates are consistent with past rate setting practices and continue to reflect increases in the energy portion only which provides a better price signal to customers, while maintaining Manitoba Hydro's competitive position with respect to rates charges by other Canadian utilities.

Hard copies of the Appendices will be distributed, and should be placed in the Application binders accordingly. Should you have any questions with respect to the foregoing, please do not hesitate to contact the writer at (204) 360-3946.

Yours truly,

MANITOBA HYDRO LAW DEPARTMENT
Per:

PATRICIA J. RAMAGE
Barrister and Solicitor

PJR/
encl.

MANITOBA	**Board Order 5/12**
THE PUBLIC UTILITIES BOARD ACT	
THE MANITOBA HYDRO ACT	
THE CROWN CORPORATIONS PUBLIC REVIEW AND ACCOUNTABILITY ACT	**January 17, 2012**

Before: Graham Lane CA, Chairman
Robert Mayer Q.C., Vice-Chair

A FINAL ORDER WITH RESPECT TO MANITOBA HYDRO'S APPLICATION FOR INCREASED 2010/11 AND 2011/12 RATES AND OTHER RELATED MATTERS

3.2.0 RATES AND MH'S 75:25 DEBT TO EQUITY TARGET

Beyond debate is the Board's jurisdiction and mandate to set just and reasonable rates for MH that are in the public interest. The public interest includes consideration of the fiscal health of the Utility as well as the impact of rates on consumers.

MH defends its requested rate increases of 2.9% for 2010/11 and another 2.9% for 2011/12 as maintaining the appropriate balance between customer sensitivity and fiscal responsibility. The fiscal responsibility includes taking note of MH's plans for $20 billion of major investments in new generation and transmission systems in MH's self-described "decade of investment" to the year 2020. It is during this "decade of investment" that MH foresees its debt-to-equity ratio eroding from the current 74:26 level to 80:20, even with annual rate increases in excess of the forecast rate of inflation.

Since 2004, the Board has continually approved rate increases for MH that have been in excess of inflation and also in excess of MH's own rate increase requests. These rate increases have in large measure contributed to the annual Net Income of the Utility and therefore to the Retained Earnings of MH. The rate increases further enabled MH to achieve its financial target of a 75:25 debt-to-equity ratio a full four years ahead of the target date sought by MH's Board of Directors.

The intention of reaching a debt-to-equity target of 75:25 was to afford consumers rate relief aligned to the rate of inflation once the ratio had been met – together with prudent management of MH's operating and other expenses. While the Board has had, and continues to have, serious concerns with the composition of what MH categorizes as "Equity", the overall target of 75:25 remains valid.

3.3.0 BOARD FINDINGS

3.3.1 Final Rates for 2010/11 and 2011/12

The Board is not prepared to finalize the existing interim rate increases of 2.9% effective April 1, 2010 and 2.0% effective April 1, 2011. The Board further denies the requested

0.9% average rate increase effective August 1, 2011. Rather, and based on the totality of the evidence before the Board, including MH Senior Vice President Mr. Warden's testimony that MH is now in its best financial position in the Utility's history, the Board finds that rate increases aligned to the forecast rates of inflation for 2010/11 and 2011/12 are just and reasonable and in the public interest. The Board will therefore approve, on a final basis, a 1.9% average rate increase effective April 1, 2010 and a further 2.0% average rate increase effective April 1, 2011.

The Board does not accept MH's contention that the rates proposed by MH represent a proper balance between customer sensitivity and fiscal responsibility. MH states that it is important that MH maintain an adequate level of retained earnings and that rates be raised gradually even during periods of exceptional water-flows. MH's application also seeks a higher level of retained earnings to provide funding for capital investments and reduce the need for borrowing, which MH states will in turn reduce the financing costs that ultimately must be recovered from ratepayers.

In the Board's opinion, MH's view of fiscal responsibility is skewed by blind adherence to a future major capital plan that has not been fully tested before an independent tribunal considering the "Needs For And Alternatives To" such a major capital expenditure plan (NFAAT). Such an NFAAT should include all facets of MH's capital expenditure plans, including the export contracts MH has entered into or plans to enter into to allow for the advancement of its capital expenditure plans.

The Board was reminded by CAC/MSOS to go back to first principles regarding its rate-setting jurisdiction with respect to MH. CAC/MSOS submitted that the Board's jurisdiction to fix just and reasonable rates carries with it the need to meet the general public interest made up of (1) the interests of ratepayers and (2) the financial health of the utility.

CAC/MSOS submitted that the final rate order should address both short-term test year revenue requirements and the long-term issues facing MH that are of concern to the

PUB, in particular respecting the "decade of investment." CAC/MSOS further submitted that rate-setting at this time must also take into account the ongoing economic uncertainty and financial stresses existing in Manitoba on all consumers, including individuals, businesses and large industry.

The Board's role, according to CAC/MSOS, must involve ensuring that MH's forecasts are reasonably reliable, ensuring that actual and projected costs incurred are necessary and prudent, assessing the reasonable revenue needs of the Corporation in the context of the overall general health of MH, determining an appropriate allocation of costs between classes, and setting just and reasonable rates in accordance with statutory objectives.

The Board endorses these principles and the objectives as set out above that must inform it in the present circumstances when fixing rates for the test years in question. As set out in this Order, the Board is not satisfied that it has sufficient proof from MH, upon consideration of all of the evidence, to support a final approval of rate increases as sought by MH. In this GRA proceeding, MH has failed to substantiate the reasonableness of its capital plans and the expected revenues to support such a capital plan. As such, the Board cannot, and will not, endorse MH's rate increase requests as applied for. However, the Board has determined that MH must receive inflationary increases for the test years to avoid erosion of its capital structure in the test years.

While MH has not made its case for the higher rate increases it requested, its financial position, arising from its Operating Results for the years ending March 31, 2010, 2011, and 2012 is significantly better than when MH filed its GRA in both MH's own assessment and the assessment of the Interveners. For the fiscal year ending March 31, 2010, MH was forecasting $121 million of Net Income. Actual Net Income was $43 million greater, at $164 million. For the fiscal year ending March 31, 2011, MH was forecasting $78 million of Net Income. Actual net income was $65 million greater, at $143 million. Finally, for the fiscal year ending March 31, 2012, MH was forecasting

$87 million of Net Income. In its latest Financial Report, MH now projects Net Income at least $42 million greater, at $130 million.

The finalized rates for the 2010/11 and 2011/12 test years do not equate to the interim rate increases that were approved in Board Orders 18/10, 30/10 and 40/11. The Board is of the view that the most expeditious way to account for the differences between the interim and final rates is for MH to establish a deferral account to track, by customer class, the difference between what was collected under the interim rates and the amount that would have been collected pursuant to the rates now finalized. That difference is to accrue interest at MH's short term borrowing rate, for the benefit of MH's consumers.

Rather than requiring MH to immediately reduce its rates, the Board orders that the rate differential between what was approved on an interim basis and what has now been finalized shall be quantified by MH and remain as an interim rate, with its associated revenues being accumulated by customer class, with accrued interest, in the previously prescribed deferral account.

The reasons for not immediately requiring rate decreases and refunds extend beyond the administrative expense and potential inequities due to customer class changes. MH had indicated that the Utility would likely be seeking further rate increases, effective April 1, 2012 – subject to confirmation by the Board of Directors of Manitoba Hydro.

While the PUB is aware that no new GRA has been approved for filing as of the date of this Order, the PUB will need to know definitively of MH's intentions in that regard to enable it to further consider its approach to what will be a new interim rate and an accumulating deferral account. As always, MH and Interveners are at liberty to make submissions to assist the Board in its deliberations on this issue.

MANITOBA

THE PUBLIC UTILITIES BOARD ACT

Order No. 116/12

August 29, 2012

BEFORE: Régis Gosselin, CGA, MBA, Chair
Raymond Lafond, BA, CMA, FCA, Member
Larry Soldier, Member

AN INTERIM MANITOBA HYDRO RATE ORDER
EFFECTIVE SEPTEMBER 1, 2012

this very early stage of the proceeding. As for the adjustment of all rates, and the issues raised by the Interveners respecting the creation of a larger base rate going into 2013/14 arising from a cumulative 4.5% series of increases on 2012/13, all of those matters are capable of variance in accordance with the Board's jurisdiction on final rate approval for MH.

The Board specifically notes that a decision to finalize the following interim rates should be taken after consideration in a full hearing when supporting evidence for the request can be fully tested by the parties:

- 2% interim rate increase granted effective April 1, 2012 in Board Order 32/12
- 1% interim rate increase initially granted in Board Order 18/10 that has been accumulating in a deferral account since the Board issued Order 5/12.

Cost of Service Studies, as an input in the rate structure for MH remains an ongoing matter affecting rate-setting and the Board is mindful of the concerns and issues raised by both MIPUG and GAC that impact rates for the various classes of consumers. Uniform rate increases across all classes could potentially disadvantage certain classes, depending on the other considerations which the Board may take into account in the existing circumstances of the rate request. As directed in Order 98/12, the Board plans to establish a process to consider MH's Cost of Service methodology. The Board is satisfied that there will be options to address costing principles and allocations for the purpose of fixing rates going forward, and does not find that the added complexity is a basis to reject the current interim rate increase across all rate classes.

The Board does not intend this Order to be a signal to MH or any party to the proceeding, or indeed to ratepayers, that it endorses a segmented interim rate process as the desirable method for rate setting for the Utility. Rather, and as submitted by MH, the Board must address an Application that is brought before it within the jurisdiction of the Board and must properly determine if the rate requested is just and reasonable on the information before it, in light of the timing of the larger ongoing GRA process and in

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Manitoba Hydro
2013 & 2014 GRA
Additional Revenue Requests ($ Millions)

		2013	2014
1% (Interim) April, 2010 [B.O. 5/12]	2011 $11.4 2012 $11.5 2013 $12.1	$35.0	$12.1
2% (Interim) April 1, 2012 [B.O. 32/12]		$25.1	$25.6
2.5% (Interim) September 1, 2012 [B.O. 116/12]		$19.9	$32.7
		$80.0	**$70.4**
3.5% April 1, 2013		-	$46.9
Total Revenue		**80.0**	**$117.3**

Source: PUB/MH I-2 (a), PUB/MH I-53

MANITOBA HYDRO
GENERAL CONSUMERS REVENUE (000's)

	2004/05 Actual	2005/06 Actual	2006/07 Actual	2007/08 Actual	2008/09 Actual	2009/10 Actual	2010/11 Actual	2011/12 Actual	2012/13 Forecast	2013/14 Forecast
Residential - Base Rates	$ 373,737	$ 360,363	$ 381,532	$ 397,742	$ 405,896	$ 401,304	$ 411,995	$ 390,436	$ 423,362	$ 432,192
General Service - Base Rates	534,958	555,836	570,078	581,124	583,448	563,954	571,525	584,748	595,056	607,475
Base Rates	908,694	916,198	951,610	978,865	989,345	965,258	983,520	975,183	1,018,418	1,039,667
2004/05 Approved Rate Increase (5.0% August 1, 2004)	30,260	45,810	47,580	48,943	49,467	48,263	49,176	48,759	50,921	51,983
2005/06 Approved Rate Increase (2.25% April 1, 2005)	-	21,645	22,482	23,126	23,373	22,804	23,236	23,039	24,060	24,562
2006/07 Approved Rate Increase (2.25% March 1, 2007)	-		1,941	25,646	23,899	23,317	23,758	23,557	24,601	25,115
2008/09 Approved Rate Increase (5.0% July 1, 2008)	-	-	-	-	40,728	52,982	53,984	53,527	55,900	57,066
2009/10 Approved Rate Increase (2.9% April 1, 2009)	-	-	-	-	-	32,266	32,877	32,598	34,043	34,753
2010/11 Interim Rate Increase (2.9% April 1, 2010)	-	-	-	-	-	-	33,830	33,543	-	-
2010/11 Approved Rate Increase (1.9% April 1, 2010)	-	-	-	-	-	-	-	-	22,951	23,430
2011/12 Approved Rate Increase (2.0% April 1, 2011)	-	-	-	-	-	-	-	23,804	24,618	25,132
2012/13 Interim Rate Increase (2.0% April 1, 2012)	-	-	-	-	-	-	-	-	25,110	25,634
Interim & Approved Rate Increases	30,260	67,455	72,003	95,715	137,468	179,633	216,861	238,827	262,205	267,675
Deferred Revenue - 2010/11 & 2011/12 (1% rate rollback)	-	-	-	-	-	-	-	(22,894)	22,894	-
Deferred Revenue - 2012/13 & 2013/14 (1% rate rollback)	-	-	-	-	-	-	-	-	12,144	12,096
Deferred Revenue from 1% rate rollback	-	-	-	-	-	-	-	(22,894)	35,038	12,096
Additional General Consumers Revenue (2.5% September 1, 2012)	-	-	-	-	-	-	-	-	19,912	32,669
Additional General Consumers Revenue (3.5% April 1, 2013)	-	-	-	-	-	-	-	-	-	46,982
Additional General Consumers Revenue	-	-	-	-	-	-	-	-	19,912	79,651
Total General Consumer Revenue	$ 938,954	$ 983,653	$ 1,023,613	$ 1,074,580	$ 1,126,812	$ 1,144,891	$ 1,200,381	$ 1,191,117	$ 1,335,571	$ 1,399,088
Rate increase requested	3.0%	2.5%	2.25%	n/a	2.9%	3.9%	2.9%	2.9%	3.5%	3.5%
Rate increase granted*	5.0%	2.25%	2.25%	n/a	5.0%	2.9%	1.9%	2.0%	2.0%/2.4%	n/a

* Please note that in Order 117/12 the PUB approved an interim rate increase of 2.4%.

MANITOBA HYDRO
EXTRAPROVINCIAL REVENUE (000's)

	2004/05 Actual	2005/06 Actual	2006/07 Actual	2007/08 Actual	2008/09 Actual	2009/10 Actual	2010/11 Actual	2011/12 Actual	2012/13 Forecast	2013/14 Forecast
Total Extraprovincial Revenue	$ 553,727	$ 826,766	$ 592,245	$ 624,971	$ 622,646	$ 426,641	$ 398,306	$ 363,044	$ 341,167	$ 362,920

Year	% Rate Increase Requested	% Approved Final/Interim	MB CPI	Annual Increase in Revenue	Cumulative % Increase	Cumulative MB CPI	Cumulative Additional Revenue From Rate Increases	% of Total Revenue from Domestic (Actual)	Actual Consolidated Debt to Equity Ratio
2003/04	0.0%	-0.72% April 1/03	0.90%	$ (6.5)	-0.72%	0.90%	$ (6.5)	72%	87:13
2004/05	3% April 1/04	5% August 1/04	2.70%	32.3	4.24%	3.62%	25.8	63%	85:15
2005/06	2.5% April 1/05	2.25% April 1/05	2.40%	21.8	6.59%	6.11%	47.6	54%	81:19
2006/07	2.25% February 1/07	2.25% March 1/07	2.00%	23.1	8.99%	8.23%	70.7	63%	80:20
2007/08	0.0% April 1/07	0.0% April 1/07	1.90%	-	8.99%	10.29%	70.7	63%	73:27
2008/09	2.9% April 1/08	5% July 1/08	2.20%	52.4	14.44%	12.72%	123.1	64%	77:23
2009/10	3.9% April 1/09	2.84% April 1/09	0.60%	32.8	17.69%	13.39%	155.9	72%	73:27
2010/11	2.9% April 1/10	2.8% interim April 1/10	1.00%	32.9	20.98%	14.53%	188.8	74%	73:27
2011/12	2.9% April 1/11	2.0% April 1/11	2.80%	24.4	23.40%	17.73%	213.2	76%	74:26
2012/13	3.5% April 1/12	2% interim April 1/12	2.00%	25.8	25.87%	20.09%	239.0	79%	76:24
2012/13	2.5% Sept 1/12	2.4% interim Sept 1/12	2.00%	31.0	28.89%	22.49%	270.0	79%	76:24
2013/14*	3.5% April 1/13	n/a	2.00%	47.4	33.40%	24.94%	317.4	79%	82:18

* To calculate the annual increase in revenue and the cumulative % rate increase, approval of a 3.5% rate increase effective April 1, 2013 has been assumed.

Please note that the proposed rate increases for 2014/15 and 2015/16 are indicative only and are subject to review and approval of the MHEB.

3

ELECTRIC OPERATIONS (MH11-2)
PROJECTED OPERATING STATEMENT
(In Millions of Dollars)

For the year ended March 31	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
REVENUES											
General Consumers											
at approved rates	1 186	1 290	1 294	1 306	1 313	1 330	1 350	1 361	1 382	1 403	1 422
additional*	0	45	106	156	208	265	325	387	455	527	603
Extraprovincial	363	341	363	394	469	502	531	554	611	821	913
Other	7	16	16	16	17	17	17	18	18	18	19
	1 556	1 693	1 778	1 873	2 007	2 114	2 224	2 320	2 466	2 769	2 957
EXPENSES											
Operating and Administrative	398	447	532	542	548	554	571	580	595	611	622
Finance Expense	385	440	452	504	537	570	640	763	803	1 147	1 109
Depreciation and Amortization	353	401	354	358	375	387	422	468	483	550	576
Water Rentals and Assessments	119	106	112	113	113	113	113	113	114	123	128
Fuel and Power Purchased	146	182	158	187	193	204	220	236	249	256	257
Capital and Other Taxes	82	87	92	99	107	116	126	132	139	128	134
Corporate Allocation	9	9	8	8	8	8	8	8	8	8	8
	1 492	1 672	1 709	1 810	1 881	1 952	2 100	2 300	2 393	2 823	2 833
Non-controlling Interest	-	(1)	(1)	(1)	(2)	(2)	(2)	(3)	(3)	(3)	(10)
Net Income	64	20	68	62	124	159	121	18	70	(57)	113
* Additional General Consumers Revenue											
Percent Increase	0.00%	3.57%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%
Cumulative Percent Increase	0.00%	4.50%	8.16%	11.94%	15.86%	19.92%	24.11%	28.46%	32.95%	37.61%	42.42%
Financial Ratios											
Equity	26%	24%	19%	17%	15%	15%	14%	13%	13%	12%	12%
Interest Coverage	1.12	1.03	1.11	1.09	1.15	1.17	1.12	1.02	1.06	0.96	1.08
Capital Coverage	1.04	1.07	1.13	1.15	1.43	1.54	1.48	1.29	1.46	1.43	1.86

ELECTRIC OPERATIONS (MH11-2)
PROJECTED OPERATING STATEMENT
(In Millions of Dollars)

For the year ended March 31	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
REVENUES										
General Consumers										
at approved rates	1 441	1 460	1 479	1 498	1 521	1 541	1 562	1 582	1 602	1 622
additional*	683	767	822	880	941	1 004	1 069	1 136	1 205	1 277
Extraprovincial	931	946	1 124	1 408	1 526	1 544	1 539	1 544	1 565	1 574
Other	19	20	20	20	21	21	22	22	23	23
	3 074	3 193	3 445	3 806	4 008	4 110	4 191	4 284	4 394	4 497
EXPENSES										
Operating and Administrative	634	646	669	676	688	700	713	727	741	755
Finance Expense	1 091	1 079	1 173	1 398	1 545	1 512	1 473	1 424	1 438	1 338
Depreciation and Amortization	579	583	615	682	733	741	753	761	793	814
Water Rentals and Assessments	129	128	135	148	153	153	153	154	155	155
Fuel and Power Purchased	269	301	282	279	301	320	332	347	359	372
Capital and Other Taxes	140	145	151	153	154	156	158	160	161	162
Corporate Allocation	8	8	8	8	8	8	8	8	8	8
	2 850	2 891	3 032	3 345	3 582	3 591	3 591	3 580	3 655	3 604
Non-controlling Interest	(10)	(11)	(11)	(11)	(12)	(12)	(13)	(13)	(14)	(14)
Net Income	213	291	402	450	415	507	588	691	726	878
* Additional General Consumers Revenue										
Percent Increase	3.50%	3.50%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
Cumulative Percent Increase	47.41%	52.57%	55.62%	58.73%	61.91%	65.14%	68.45%	71.82%	75.25%	78.76%
Financial Ratios										
Equity	12%	13%	14%	15%	17%	19%	21%	23%	26%	29%
Interest Coverage	1.14	1.19	1.26	1.28	1.26	1.33	1.38	1.46	1.49	1.63
Capital Coverage	1.93	1.99	2.04	2.36	2.32	2.57	2.59	2.65	3.34	3.00

ELECTRIC OPERATIONS (MH11-2)
PROJECTED BALANCE SHEET
(In Millions of Dollars)

For the year ended March 31	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
ASSETS											
Plant in Service	13 795	15 212	15 723	16 485	17 410	17 993	21 415	21 904	25 521	28 275	28 636
Accumulated Depreciation	(4 917)	(5 266)	(5 581)	(5 911)	(6 272)	(6 638)	(7 065)	(7 539)	(8 028)	(8 583)	(9 165)
Net Plant in Service	8 878	9 947	10 142	10 574	11 138	11 355	14 351	14 365	17 492	19 692	19 472
Construction in Progress	2 443	2 196	3 149	3 997	5 014	6 410	5 346	6 447	4 558	3 595	4 964
Current and Other Assets	1 906	1 864	1 327	1 372	1 559	1 740	1 987	1 779	1 951	2 171	2 048
Goodwill and Intangible Assets	181	179	162	149	136	126	117	109	103	97	93
Regulated Assets	240	241	-	-	-	-	-	-	-	-	-
	13 648	14 426	14 780	16 092	17 847	19 631	21 800	22 701	24 105	25 555	26 577
LIABILITIES AND EQUITY											
Long-Term Debt	9 253	9 469	10 909	12 169	13 789	15 260	17 025	18 518	19 480	20 990	22 434
Current and Other Liabilities	1 351	1 917	1 407	1 520	1 574	1 736	2 035	1 432	1 810	1 814	1 289
Contributions in Aid of Construction	317	328	341	348	355	365	376	386	396	407	418
Retained Earnings	2 391	2 411	2 203	2 265	2 389	2 548	2 669	2 687	2 757	2 700	2 814
Accumulated Other Comprehensive Income	335	302	(79)	(209)	(261)	(279)	(306)	(322)	(338)	(356)	(379)
	13 648	14 426	14 780	16 092	17 847	19 631	21 800	22 701	24 105	25 555	26 577
Equity Ratio	26%	24%	19%	17%	15%	15%	14%	13%	13%	12%	12%

ELECTRIC OPERATIONS (MH11-2)
PROJECTED BALANCE SHEET
(In Millions of Dollars)

For the year ended March 31	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
ASSETS										
Plant in Service	29 045	29 610	34 023	38 098	39 357	39 988	40 557	41 087	43 107	43 823
Accumulated Depreciation	(9 752)	(10 344)	(10 970)	(11 663)	(12 407)	(13 160)	(13 926)	(14 701)	(15 509)	(16 338)
Net Plant in Service	19 293	19 267	23 053	26 435	26 951	26 828	26 631	26 386	27 599	27 485
Construction in Progress	6 099	6 969	4 170	1 022	545	786	1 259	1 722	618	758
Current and Other Assets	2 158	2 426	2 660	2 640	3 029	3 431	3 695	3 929	4 486	5 143
Goodwill and Intangible Assets	91	89	88	86	85	83	82	81	81	80
Regulated Assets	-	-	-	-	-	-	-	-	-	-
	27 641	28 752	29 972	30 183	30 609	31 128	31 667	32 118	32 783	33 466
LIABILITIES AND EQUITY										
Long-Term Debt	23 437	24 240	24 593	24 795	24 796	24 738	24 489	24 391	24 180	23 152
Current and Other Liabilities	1 140	1 146	1 599	1 146	1 145	1 203	1 390	1 236	1 374	2 193
Contributions in Aid of Construction	429	440	451	463	475	487	499	512	525	538
Retained Earnings	3 026	3 317	3 719	4 170	4 584	5 092	5 679	6 370	7 096	7 974
Accumulated Other Comprehensive Income	(392)	(391)	(391)	(391)	(391)	(391)	(391)	(391)	(391)	(391)
	27 641	28 752	29 972	30 183	30 609	31 128	31 667	32 118	32 783	33 466
Equity Ratio	12%	13%	14%	15%	17%	19%	21%	23%	26%	29%

ELECTRIC OPERATIONS (MH11-2)
PROJECTED CASH FLOW STATEMENT
(In Millions of Dollars)

For the year ended March 31	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
OPERATING ACTIVITIES											
Cash Receipts from Customers	1 556	1 693	1 778	1 873	2 007	2 114	2 224	2 320	2 466	2 769	2 957
Cash Paid to Suppliers and Employees	(742)	(816)	(886)	(931)	(951)	(976)	(1 018)	(1 048)	(1 084)	(1 103)	(1 125)
Interest Paid	(406)	(466)	(475)	(516)	(564)	(598)	(683)	(817)	(841)	(1 188)	(1 151)
Interest Received	26	28	27	20	27	34	41	43	40	36	35
	434	439	444	447	519	574	564	499	580	514	717
FINANCING ACTIVITIES											
Proceeds from Long-Term Debt	811	900	1 630	1 405	1 990	2 000	2 590	1 800	1 590	2 190	1 590
Sinking Fund Withdrawals	23	129	395	105	24	-	4	424	177	265	689
Retirement of Long-Term Debt	(25)	(119)	(808)	(179)	(312)	(408)	(530)	(837)	(309)	(640)	(692)
Other	(81)	(21)	(14)	(5)	(7)	(7)	(7)	(16)	(5)	26	(6)
	729	889	1 203	1 326	1 695	1 585	2 057	1 371	1 452	1 841	1 581
INVESTING ACTIVITIES											
Property, Plant and Equipment, net of contributions	(1 163)	(1 226)	(1 481)	(1 616)	(1 934)	(1 986)	(2 336)	(1 567)	(1 820)	(1 856)	(1 697)
Sinking Fund Payment	(98)	(117)	(208)	(124)	(192)	(157)	(231)	(209)	(219)	(288)	(346)
Other	(19)	(20)	(20)	(21)	(19)	(46)	(36)	(30)	(30)	(34)	(40)
	(1 280)	(1 363)	(1 709)	(1 761)	(2 146)	(2 189)	(2 603)	(1 806)	(2 069)	(2 179)	(2 083)
Net Increase (Decrease) in Cash	(116)	(36)	(62)	12	68	(29)	18	64	(36)	176	215
Cash at Beginning of Year	66	(50)	(86)	(148)	(135)	(67)	(96)	(79)	(15)	(51)	126
Cash at End of Year	(50)	(86)	(148)	(135)	(67)	(96)	(79)	(15)	(51)	126	340

ELECTRIC OPERATIONS (MH11-2)
PROJECTED CASH FLOW STATEMENT
(In Millions of Dollars)

For the year ended March 31	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
OPERATING ACTIVITIES										
Cash Receipts from Customers	3 074	3 193	3 445	3 806	4 008	4 110	4 191	4 284	4 394	4 497
Cash Paid to Suppliers and Employees	(1 154)	(1 201)	(1 215)	(1 234)	(1 272)	(1 303)	(1 329)	(1 358)	(1 383)	(1 410)
Interest Paid	(1 108)	(1 092)	(1 196)	(1 433)	(1 582)	(1 561)	(1 534)	(1 490)	(1 484)	(1 423)
Interest Received	20	21	31	36	38	49	60	64	71	84
	832	921	1 066	1 175	1 192	1 295	1 388	1 501	1 598	1 748
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	980	790	790	190	(10)	-	(10)	(10)	(30)	(10)
Sinking Fund Withdrawals	159	-	-	401	-	-	60	250	-	13
Retirement of Long-Term Debt	(159)	-	-	(450)	-	-	(60)	(220)	(100)	(213)
Other	(7)	(6)	(6)	(8)	(8)	(7)	(7)	(6)	(4)	(19)
	973	784	784	133	(18)	(7)	(17)	14	(134)	(229)
INVESTING ACTIVITIES										
Property, Plant and Equipment, net of contributions	(1 510)	(1 401)	(1 578)	(891)	(746)	(834)	(1 003)	(953)	(876)	(814)
Sinking Fund Payment	(234)	(246)	(263)	(282)	(274)	(285)	(297)	(306)	(305)	(317)
Other	(29)	(30)	(27)	(28)	(30)	(28)	(29)	(29)	(29)	(30)
	(1 773)	(1 677)	(1 869)	(1 201)	(1 051)	(1 148)	(1 328)	(1 288)	(1 211)	(1 160)
Net Increase (Decrease) In Cash	32	28	(19)	108	124	140	43	227	253	359
Cash at Beginning of Year	340	372	400	381	489	613	752	796	1 023	1 276
Cash at End of Year	372	400	381	489	613	752	796	1 023	1 276	1 635

PUB/MH I-22

Reference: IFF11-2 – Electric Operations

a) Please refile the IFF11-2 electric operations for the 20 year outlook including financial targets for each year.

ANSWER:

Please note that while financial targets have been calculated based on electric operations only in the following attachment, as requested, Manitoba Hydro's financial targets apply to consolidated operations only.

4

1A

Manitoba Hydro
Fiscal Years 2010;2011;2012
IFF09 vs. Actual Results

ELECTRIC OPERATIONS
PROJECTED OPERATING STATEMENT
(In Millions of Dollars)

	2010			2011			2012			
For the Year ended March 31	**Actual**	**IFF09**	**Difference**	**Actual**	**IFF09**	**Difference**	**Actual**	**IFF09**	**Difference**	
REVENUES										
General Consumers										
at approved rates	1,156	1,160	(4)	1,177	1,159	18	1,170	1,177	(7)	
additional	-	-	-	33	33	-	57	69	(12)	
1% Deferral	-	-	-	-	-		(23)	-	(23)	
Extraprovincial	427	414	13	398	383	15	363	554	(191)	
Other	6	7	(1)	6	7	(1)	6	8	(2)	
	1,589	1,581	8	1,615	1,584	31	1,573	1,808	(235)	
EXPENSES										
Operating and Administrative	379	372	7	401	380	21	410	403	7	
Finance Expense	373	417	(44)	388	413	(25)	385	468	(83)	
Depreciation and Amortization	358	368	(10)	366	386	(20)	353	407	(54)	
Water Rentals and Assessments	121	120	1	120	110	10	119	111	8	
Fuel and Power Purchased	104	103	1	106	132	(26)	146	248	(102)	
Capital and Other Taxes	76	73	3	82	76	6	84	77	7	
Corporate Allocation	8	8	-	9	9	-	9	9	-	
	1,419	1,460	(41)	1,472	1,505	(33)	1,506	1,723	(217)	
Non-controlling Interest	-	1	(1)	-	-	-	-	1	(1)	
Net Income	170	121	49	143	78	65	67	87	(20)	94
Retained Earnings	2,206	2,183	23	2,349	2,261	88	2,416	2,331	85	
Debt Ratio	73	74	(1)	73	75	(2)	74	76	(2)	

Sources:
Rate Increases - PUB/MH I-53
Actual Results - Annual Reports - Segmented Information

Manitoba Hydro
Fiscal Years 2013; 2014
IFF09 vs. IFF11-2

ELECTRIC OPERATIONS
PROJECTED OPERATING STATEMENT
2012 & 2013 GRA
(In Millions of Dollars)

	2013			2014			2015			2016			
For the Year ended March 31,	**IFF11-2**	**IFF09**	**Difference**	**IFF11-2**	**IFF09**	**Difference**	**IFF11-2**	**IFF09**	**Difference**	**IFF11-2**	**IFF09**	**Difference**	
REVENUES													
General Consumers													
at approved rates	1,208	1,191	17	1,233	1,204	29	1,247	1,229	18	1,253	1,244	9	
additional	93	113	(20)	154	161	(7)	204	212	(8)	256	266	(10)	
1% Deferral	35	-	35	12	-	12	12	-	12	12	-	12	
Extraprovincial	341	583	(242)	363	615	(252)	394	590	(196)	469	701	(232)	
Other	16	8	8	16	8	8	16	8	8	17	8	9	
	1,693	**1,895**	**(202)**	**1,778**	**1,988**	**(210)**	**1,873**	**2,039**	**(166)**	**2,007**	**2,219**	**(212)**	
EXPENSES													
Operating and Administrative	447	411	36	532	420	112	542	428	114	548	437	111	
Finance Expense	440	525	(85)	452	527	(75)	504	544	(40)	537	529	8	
Depreciation and Amortization	401	435	(34)	354	446	(92)	358	466	(108)	375	476	(101)	
Water Rentals and Assessments	106	113	(7)	112	114	(2)	113	114	(1)	113	115	(2)	
Fuel and Power Purchased	182	250	(68)	158	260	(102)	187	269	(82)	193	297	(104)	
Capital and Other Taxes	87	80	7	92	85	7	99	92	7	107	100	7	
Corporate Allocation	9	9	-	8	9	(1)	8	9	(1)	8	9	(1)	
	1,672	**1,824**	**(152)**	**1,708**	**1,861**	**(153)**	**1,811**	**1,922**	**(111)**	**1,881**	**1,963**	**(82)**	
Non-controlling Interest	(1)	1	(2)	(1)	(2)	1	(1)	(5)	4	(2)	(9)	7	
Net Income	**20**	**72**	**(52)**	**68**	**125**	**(57)**	**62**	**113**	**(51)**	**124**	**248**	**(124)**	**(284)**
Retained Earnings	2,411	2,403	8	2,203	2,528	(325)	2,265	2,641	(376)	2,389	2,889	(500)	
Debt Ratio	76	76	-	82	78	4	84	79	5	85	80	5	

Sources
Rate increases - PUB/MH I- 53

File Name: IFF11-2 Comparative Analysis (version 1) Electric 11-2 vs 09-1

PUB/MH I-22

Reference: IFF11-2 – Electric Operations

b) **Please provide a comparison of the IFF forecast for IFF11-2 – electric operation with IFF09 for each of the comparative years between the two forecasts and comment on the reasons for the changes.**

ANSWER:

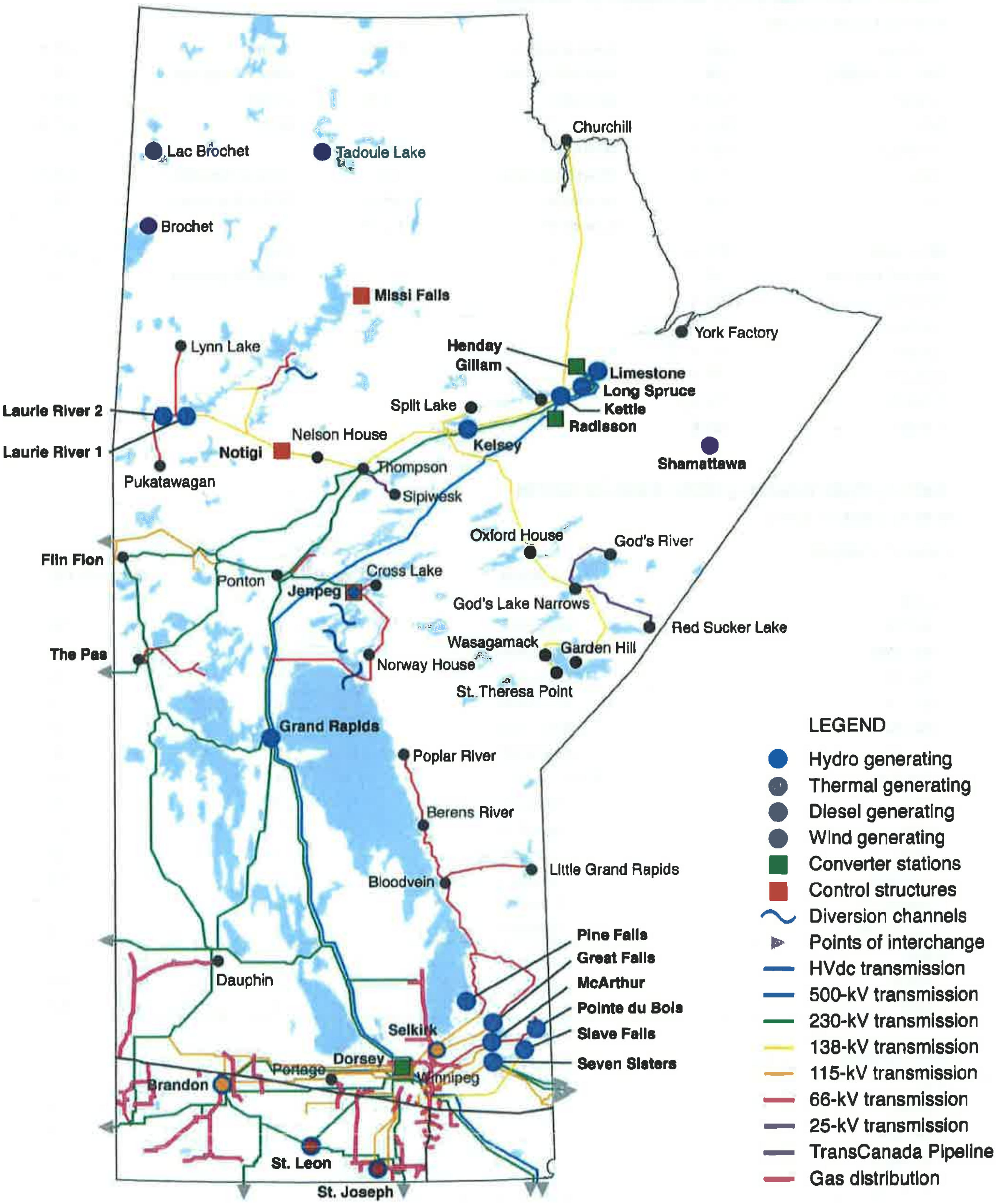
Please see attachment.

ELECTRIC OPERATIONS
COMPARISON OF MH11-2 To MH09-1
INCREASE / (DECREASE)
(In Millions of Dollars)

ACCOUNT	2012	2013	2014	CUMULATIVE 2012-2020	VARIANCE EXPLANATION
REVENUES					
General Consumers Revenue including Projected Rate Increases	(60)	31	35	129	Lower General Service revenues in the early portion due to the economic recession. The cumulative percent increase is much lower in MH11-2 compared to MH09-1 given the rate increases started in 2010/11 in MH09-1. Residential customer growth is higher due to increased immigration with spin-off effects on GS load growth. Offset by EIIR revenue removal from forecast for IFF11-2.
Extraprovincial	(191)	(241)	(252)	(2,373)	Lower throughout forecast due to lower prices, increased Manitoba demand, a reduction of contracted energy delivered, reduced capacity for the US interconnection and a stronger Canadian dollar. Also decrease the forecast due to Wuskatim GS deferral.
Other	(1)	8	8	67	Higher due to the reclassification of Operating Expense Recoveries to Other Income as a result of adoption of IFRS.
Total Revenue	(252)	(203)	(209)	(2,178)	
EXPENSES					
Operating and Administrative	(5)	36	112	780	Increased primarily due to IFRS adjustments and CGAAP accounting changes, slightly offset by cost reductions.
Finance Expense	(82)	(86)	(75)	(183)	Lower primarily due to favourable interest rates and stronger Canadian dollar.
Depreciation and Amortization	(54)	(35)	(92)	(709)	Lower due to elimination of negative salvage value and regulated asset amortization partially offset by change to equal life group methodology related to IFRS implementation. Also lower due to increase in estimated asset lives.
Water Rentals and Assessments	9	(7)	(2)	(19)	Increased in 2012 due to expected flows in IFF11-2 vs average flow forecast in IFF09. Decreased in 2013 and 2014 due to Wuskatim GS deferral and lower average flows.
Fuel and Power Purchased	(103)	(67)	(102)	(1,113)	Favourable water flows in 2012 reduce the requirement for thermal generation and imports. Decreased primarily due to lower market prices and stronger Canadian dollar.
Capital and Other Taxes	5	8	7	77	Higher capital tax due to increased financing requirements. Also increased payments to Gillam Townsite and Frontier School Division for grants in lieu of taxes.
Corporate Allocation	(0)	(0)	(1)	(4)	
Total Expenses	(230)	(152)	(151)	(1,170)	
Non-controlling Interest	(1)	(2)	1	50	
Change in Net Income	(23)	(53)	(57)	(958)	

5

MAJOR ELECTRICAL AND GAS FACILITIES



SOURCES OF ELECTRICAL ENERGY

Sources of Electrical Energy Generated and Purchased

For the Year Ended March 31, 2012

Nelson River	**79.98 %**
Billion kWh generated	**27.6**
Limestone	27.01 %
Kettle	24.96 %
Long Spruce	20.89 %
Kelsey	5.19 %
Jenpeg	1.93 %
Winnipeg River	**8.73 %**
Billion kWh generated	**3.0**
Seven Sisters	2.35 %
Great Falls	2.10 %
Pine Falls	1.40 %
Pointe du Bois	0.99 %
Slave Falls	0.98 %
McArthur	0.91 %

Saskatchewan River	**7.35 %**
Billion kWh generated	**2.5**
Grand Rapids	7.35 %
Laurie River	**0.10 %**
Billion kWh generated	**0.0**
Laurie River #1	0.05 %
Laurie River #2	0.05 %

Thermal	**0.22 %**
Billion kWh generated	**0.1**
Brandon	0.18 %
Selkirk	0.04 %
Purchases (excl. wind)	**0.98 %**
Billion kWh purchased	**0.3**
Wind	**2.64 %**
Billion kWh purchased	**0.9**

Manitoba Hydro Generating Stations and Capabilities

For the Year Ended March 31, 2012

Interconnected Capabilities

Station	Location	Number of units	Net Capability (MW)
Hydraulic			
Great Falls	Winnipeg River	6	129
Seven Sisters	Winnipeg River	6	165
Pine Falls	Winnipeg River	6	88
McArthur	Winnipeg River	8	55
Pointe du Bois	Winnipeg River	16	75
Slave Falls	Winnipeg River	8	67
Grand Rapids	Saskatchewan River	4	479
Kelsey	Nelson River	7	250
Kettle	Nelson River	12	1 220
Jenpeg	Nelson River	6	129
Long Spruce	Nelson River	10	1 010
Limestone	Nelson River	10	1 340
Laurie River (2)	Laurie River	3	10
Thermal			
Brandon		3	333
Selkirk		2	125

Isolated Capabilities

Diesel	
Brochet	3
Lac Brochet	2
Shamattawa	3
Tadoule Lake	2

Total Generating Capability	**5 485**

The following table contains information related to the operating results, assets, liabilities, contributions in aid of construction and retained earnings by segment:

	Electricity		Gas		Corporate		Total	
	2012	2011	2012	2011	2012	2011	2012	2011
	millions of dollars							
Revenues [1]	1 573	1 616	132	143	-	-	1 705	1 759
Expenses								
Operating and administrative	410	402	62	61	-	-	472	463
Finance expense	385	388	19	18	19	19	423	425
Depreciation and amortization	353	366	26	25	2	2	381	393
Water rentals and assessments	119	120	-	-	-	-	119	120
Fuel and power purchased	146	106	-	-	-	-	146	106
Capital and other taxes	84	82	19	20	-	-	103	102
Corporate allocation	9	9	12	12	(21)	(21)	-	-
	1 506	1 473	138	136	-	-	1 644	1 609
Net Income (loss)	67	143	(6)	7	-	-	61	150
Total assets	13 203	12 288	588	594	-	-	13 791	12 882
Total liabilities	10 196	9 345	400	399	-	-	10 596	9 744
Contributions in aid of construction	285	262	33	33	-	-	318	295
Retained earnings	2 416	2 349	34	40	-	-	2 450	2 389

(1) Revenues are stated net of cost of gas sold of $197 million (2011 - $261 million) and Manitoba Hydro International project costs of $19 million (2011 - $23 million).

NOTE 24 COMPARATIVE FIGURES

Where appropriate, comparative figures for 2011 have been reclassified in order to conform to the presentation adopted in 2012.

FINANCIAL STATISTICS

For the year ended March 31	2012	2011	2010	2009	2008	2007	2006	2005	2004	2003
					millions of dollars					
Revenues										
Electrical:										
Residential	490	503	476	463	436	410	387	386	368	354
General service	701	697	669	664	636	614	597	553	550	521
Extraprovincial	363	398	427	623	625	592	827	554	351	463
Other revenue	19	18	11	21	13	11	10	9	11	10
Gas:										
Residential	172	205	222	292	268	258	245	244	235	247
Commercial / Industrial	151	193	225	281	254	244	267	256	252	261
Transportation	5	5	5	5	4	4	3	5	4	4
Other revenue	1	1	2	2	2	2	2	2	3	3
	1 902	2 020	2 037	2 351	2 240	2 135	2 338	2 011	1 774	1 863
Expenses										
Operating and administrative	472	463	440	429	381	361	368	357	339	320
Finance expense	423	425	410	471	440	506	503	502	487	479
Depreciation and amortization	361	393	384	368	349	332	322	311	296	281
Water rentals and assessments	119	120	121	123	124	112	131	111	71	103
Fuel and power purchased	146	106	104	176	134	226	125	135	569	151
Capital and other taxes	103	102	99	87	80	77	77	75	73	66
Cost of gas sold	197	261	316	431	386	379	397	384	375	392
	1 841	1 870	1 874	2 085	1 894	2 013	1 923	1 875	2 210	1 792
Net income	61	150	163	266	346	122	415	136	(436)	71
Assets										
Property, plant and equipment	13 631	12 967	12 688	12 300	11 864	11 424	11 065	10 748	10 399	9 991
Less accumulated depreciation	4 984	4 752	4 612	4 356	4 167	3 924	3 657	3 447	3 241	3 042
Construction in progress	3 150	2 739	2 052	1 438	1 238	678	602	475	378	356
Sinking fund investments	372	282	822	666	718	630	555	562	715	948
Current and other assets	1 622	1 646	1 487	1 499	2 113	1 914	1 917	1 614	1 652	1 981
	13 791	12 882	12 437	11 547	11 766	10 922	10 482	9 952	9 903	10 234
Liabilities and Retained Earnings										
Long-term debt	9 101	8 617	8 228	7 668	7 218	6 822	7 051	7 048	7 114	6 925
Current and other liabilities	1 495	1 127	1 328	1 637	2 097	2 380	1 849	1 738	1 781	1 875
Contributions in aid of construction	318	295	295	296	300	298	297	296	274	264
Non-controlling interest	100	87	62	39	24	15	-	-	-	-
Retained earnings	2 450	2 369	2 239	2 076	1 822	1 407	1 285	870	734	1 170
Accumulated other comprehensive income	327	367	285	(169)	305	-	-	-	-	-
	13 791	12 882	12 437	11 547	11 766	10 922	10 482	9 952	9 903	10 234
Cash Flows										
Operating activities	567	595	589	686	633	443	710	433	(127)	432
Financing activities	725	674	1 124	424	487	227	77	236	753	213
Investing activities	1 312	1 373	1 698	1 086	986	786	677	666	650	629
Financial Indicators										
Interest coverage[1]	1.10	1.27	1.32	1.49	1.69	1.23	1.77	1.25	0.17	1.14
Debt ratio[2]	0.74	0.73	0.73	0.77	0.73	0.80	0.81	0.85	0.87	0.80
Capital coverage[3]	1.13	1.25	1.30	1.77	1.62	1.10	2.28	1.20	(0.32)	1.10

[1]Interest coverage represents net income plus interest on debt divided by interest on debt.

[2]Debt ratio represents debt (long-term debt plus notes payable minus sinking fund investments and temporary investments) divided by debt plus equity plus contributions in aid of construction.

[3]Capital coverage represents internally generated funds divided by capital construction expenditures.

OPERATING STATISTICS

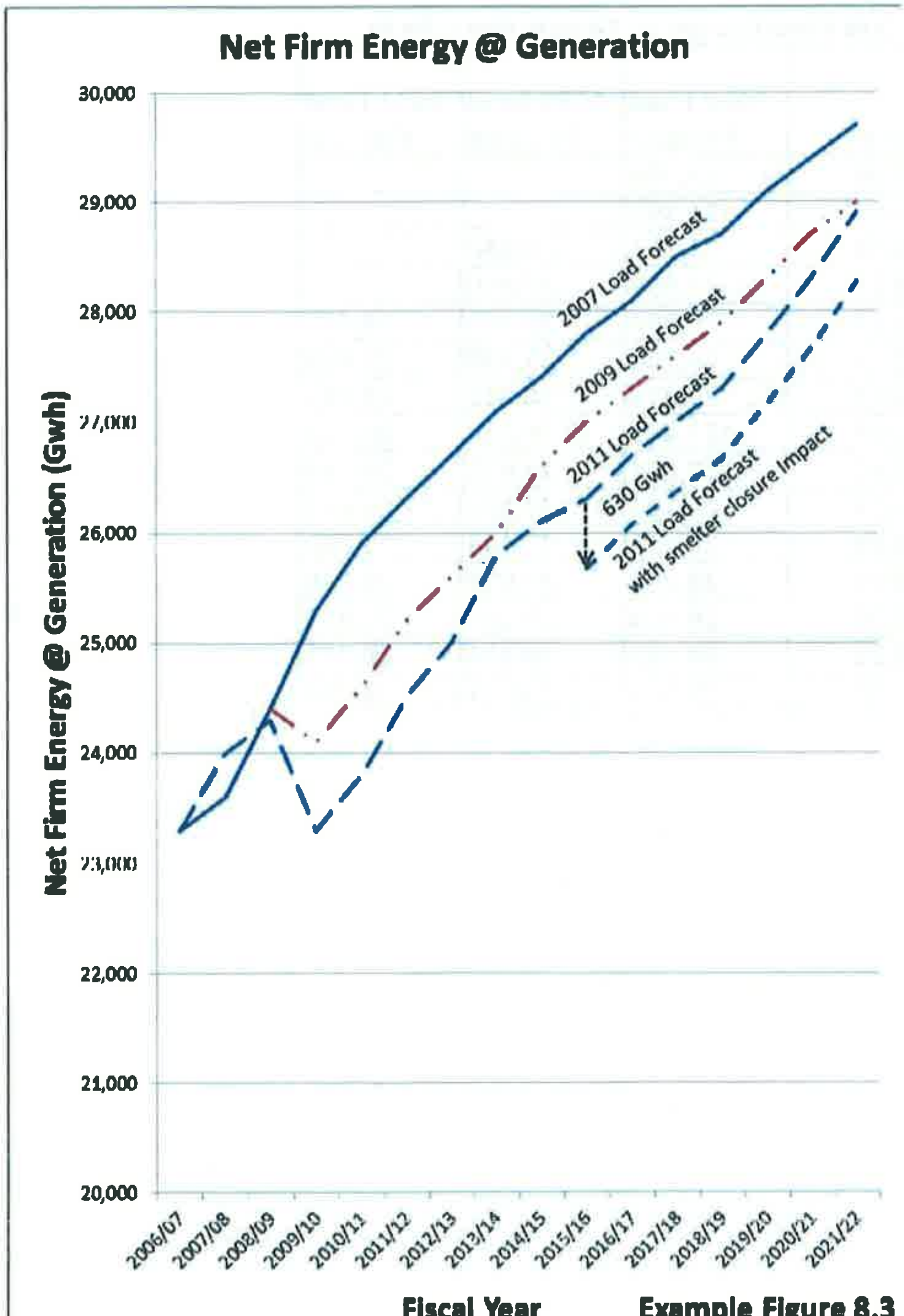
For the year ended March 31	2012	2011	2010	2009	2008	2007	2006	2005	2004	2003
Electric System Capability										
Capability (000 kW)	5 456	5 489	5 501	5 480	5 465	5 461	5 469	5 470	5 471	5 484
Manitoba firm peak demand (000 kW)	4 343	4 261	4 359	4 477	4 273	4 184	4 054	4 189	3 959	3 916
Percent change	1.9	(2.2)	(2.6)	4.8	2.1	3.2	(2.8)	5.3	1.1	4.1
Electric System Supply										
Total energy supplied (millions of kWh)										
Generation	33 235	34 102	33 961	34 528	35 354	32 132	37 620	31 548	19 338	29 167
Isolated systems	14	13	13	13	12	12	12	11	11	11
	33 249	34 115	33 974	34 541	35 366	32 144	37 632	31 559	19 349	29 178
Electric Load at Generation (millions of kWh)										
Integrated system	23 499	23 783	23 295	24 285	23 985	23 327	22 622	22 452	21 907	21 965
Isolated system	14	13	13	13	12	12	12	11	11	11
	23 513	23 796	23 308	24 298	23 997	23 339	22 634	22 463	21 918	21 976
Percent change	(1.2)	2.1	(4.1)	1.3	2.8	3.1	0.8	2.5	(0.3)	7.0
Electric System Deliveries (millions of kWh)										
Energy delivered in Manitoba										
Residential	6 930	7 060	6 899	6 954	6 838	6 539	6 266	6 370	6 266	6 135
General service	13 840	13 727	13 587	14 256	14 223	13 965	13 669	13 365	13 014	12 143
	20 770	20 787	20 486	21 210	21 061	20 504	19 935	19 735	19 280	18 278
Extraprovincial	10 244	10 344	10 860	10 122	11 086	10 100	13 773	10 475	6 966	9 735
	31 014	31 131	31 346	31 332	32 147	30 604	33 708	30 210	26 246	28 013
Gas Deliveries (millions of cubic metres)										
Residential	509	591	581	696	682	653	600	681	653	714
Commercial / Industrial	728	821	803	866	856	811	782	917	893	980
Transportation	629	584	619	603	618	592	598	559	577	640
	1 866	1 996	2 003	2 165	2 156	2 056	1 980	2 157	2 123	2 334
Number of Customers										
Electric:										
Residential	474 661	469 635	465 055	460 804	455 430	450 823	446 370	442 840	438 953	435 507
General service	68 020	67 664	67 304	66 668	66 169	66 038	63 421	62 826	62 697	62 218
	542 681	537 299	532 359	527 472	521 599	516 861	509 791	505 666	501 650	497 725
Gas:										
Residential	242 813	241 123	239 535	239 597	237 724	236 086	234 108	231 366	229 194	227 071
Commercial / Industrial	24 886	24 838	24 766	23 411	23 435	23 483	23 709	24 559	24 437	24 202
	267 699	265 961	264 301	263 008	261 159	259 569	257 817	255 925	253 631	251 273
Number of Employees										
Regular	4 631	4 860	4 777	4 752	4 709	4 406	4 409	4 386	4 389	4 399
Construction	1 693	1 439	1 424	1 266	1 107	1 161	1 154	1 098	1 006	966
	6 324	6 299	6 201	6 018	5 816	5 567	5 563	5 484	5 395	5 365

6

PUB/MH I-120

Reference: 2011 Load Forecast – Appendix 8.1 Page 39 – Total Energy Forecast

d) Please file MH's own version and data points of Example Figure 8.3 Net Firm Energy at Generation (2011 and prior years forecasts).



Example Figure 8.3

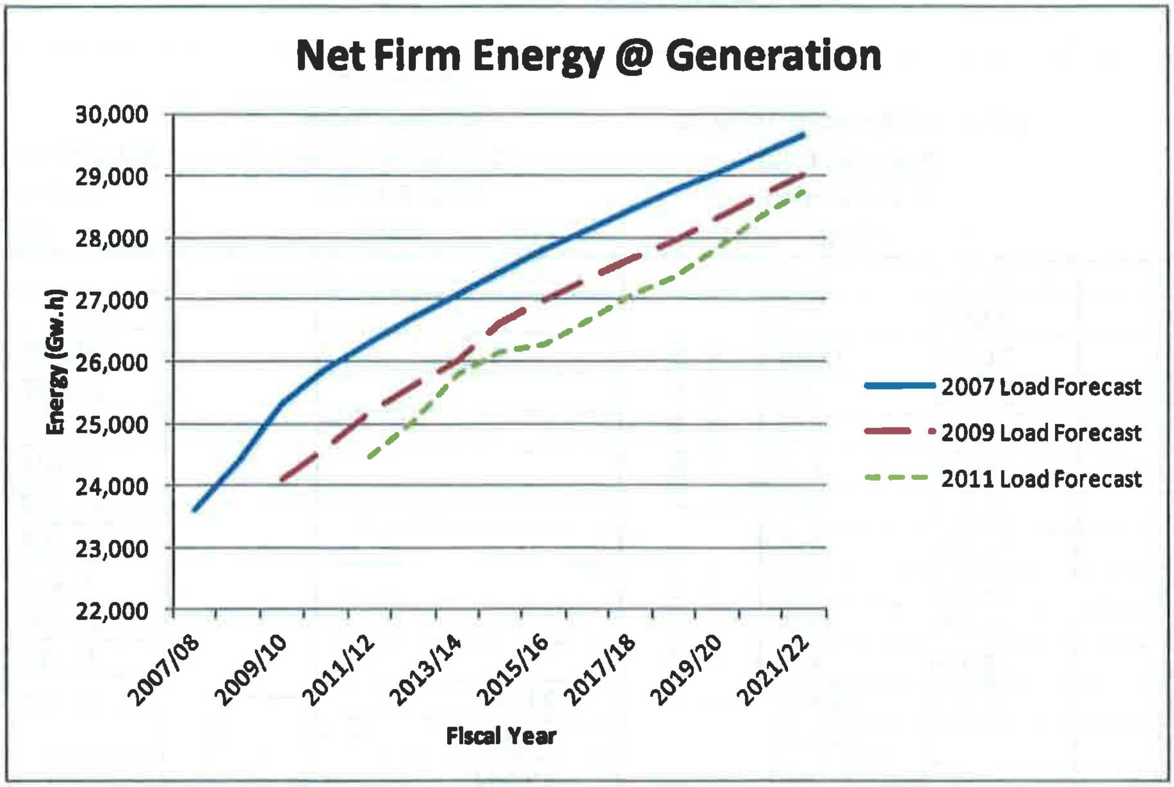
ANSWER:

The 2011 Electric Load Forecast includes the forecast impact of the reported Northern Manitoba smelter closure, which can be seen in the graph as the decrease beginning in 2014/15 and 2015/16.

Net Firm Energy @ Generation (Gw.h)

Fiscal Yr	2007 Load Forecast	2009 Load Forecast	2011 Load Forecast
2007/08	23,596		
2008/09	24,398		
2009/10	25,323	24,080	
2010/11	25,869	24,600	
2011/12	26,290	25,159	24,475
2012/13	26,706	25,599	25,030
2013/14	27,079	26,012	25,787
2014/15	27,441	26,618	26,141
2015/16	27,804	26,973	26,264
2016/17	28,126	27,331	26,651
2017/18	28,453	27,644	27,062
2018/19	28,748	27,923	27,338
2019/20	29,050	28,288	27,823
2020/21	29,355	28,654	28,319
2021/22	29,660	29,021	28,744

jC


Net Firm Energy @ Generation
30,000
29,000
28,000
27,000
26,000
25,000
24,000
23,000
22,000
Energy (Gw.h)
2007/08
2009/10
2011/12
2013/14
2015/16
2017/18
2019/20
2021/22
Fiscal Year
2007 Load Forecast
2009 Load Forecast
2011 Load Forecast

Domestic Load Growth

	2011 Load Forecast Table 22 Domestic Load at Generation (Gwh)			Attachment 5 Average Prices Calculated IFF11-2 Sales & Losses (Gwh)			2011/12 Annual Report at Generation (Gwh)	
00/01	20,075		+3230/6 yrs 538/yr (2.5%)					
01/02	20,494	419						
02/03	21,940	1,446					21,965	+1362/4 yrs 340/yr (1.5%)
03/04	21,890	-50					21,907	
04/05	22,426	536					22,452	
05/06	22,598	172					22,622	
06/07	23,305	707	+208/5yrs 43/yr (0.2%)				23,327	+172/5 yrs 34/yr (0.15%)
07/08	23,961	656					23,985	
08/09	24,262	301					24,285	
09/10	23,275	-803					23,295	
10/11	23,758	483					23,783	
11/12	23,513	24,475		23,745		+2555/5yrs 511/yr (2.0%)	23,499	
12/13		25,030		24,910	1,397			
13/14		25,787		25,442	532			
14/15		26,141		25,711	269			
15/16		26,264		25,760	49			
16/17		26,651		26,068	308	+1578/5yrs 316/yr (1.2%)		
17/18		27,062		26,195				
18/19		27,338		26,411				
19/20		27,823		26,828				
20/21		28,319		27,257				
21/22				27,646				

Figure 8.3

DE

Residential Load Forecast

Ref: PUB/MH I-117 (b) /2011 Load Forecast
2011/12 Annual Report Table 6

	Electric Heat (Gwh)		STD (Gwh)		Total Residential (Gwh)		Annual Report (Gwh)	
98/99	2,774		2,609		5,384		—	
99/00	2,757		2,607		5,364			
00/01	3,001		2,736		5,737			
01/02	2,902		2,771		5,674			
02/03	3,289		2,977		6,266		6,135	
03/04	3,151		3,019		6,170		6,266	131
04/05	3,283		2,991		6,275		6,370	104
05/06	3,126		3,045		6,171		6,266	-104
06/07	3,275		3,167		6,443		6,539	273
07/08	3,499	3,300	3,237	3,146	6,736		6,838	299
08/09	3,604	3,473	3,273	3,203	6,847		6,954	116
09/10		3,505		3,249			6,899	-55
10/11		3,661		3,391	6,952		7,060	161
11/12		4,157		2,961		7,118	6,930	-100
12/13		4,232		2,983		7,216		
13/14		4,316		3,010		7,326		
14/15		4,400		3,037		7,438		
15/16		4,487		3,067		7,554		
16/17		4,575		3,098		7,673		
17/18		4,664		3,130		7,794		
18/19		4,753		3,163		7,916		
19/20		4,841		3,197		8,039		
20/21		4,929		3,233		8,162		
21/22		5,016		3,267		8,285		
22/23		5,103		3,305		8,408		
23/24		5,188		3,343		8,531		
24/25		5,073		3,382		8,654		
25/26		5,356		3,421		8,777		

+418/5 yr 82/yr (2%)

+882/ 4 yrs 220/yr (8.9 %)

+703/ 4 yrs 141/yr (2.2%)

+92/4 yrs 20/yr (0.3%)

+555/5 yrs 111/yr (1.5%)

+612/5 yrs 122/yr (1.5%)

Figure 8.4

PUB/MH I-117

Reference: **Tab 8 2011 Load Forecast P. 15/Prior Load Forecasts**

Preamble: **Please provide a tabular and graphical comparison of the 2011, 2010, 2009, 2008 and 2007 electric load forecasts; separately illustrating:**

b) Fuel Switching MH Projection of Electric Heat Energy Usage

Please reconcile the 2011 forecast with the 2007 to 2009 forecasts of electric heat customer numbers and their usage; also provide data for non-electric.

ANSWER:

Number of Residential Customers

	2007 Forecast Electric Heat	2008 Forecast Electric Heat	2009 Forecast Electric Heat	2010 Forecast Electric Heat	2011 Forecast Electric Heat
2007/08	134,544				
2008/09	136,698	137,798			
2009/10	138,745	140,160	141,121		
2010/11	140,679	142,416	143,520	145,295	
2011/12	142,505	144,581	145,960	147,686	160,849
2012/13	144,265	146,709	148,406	149,867	164,043
2013/14	145,975	148,795	150,839	151,902	167,547
2014/15	147,646	150,842	153,254	153,919	171,056
2015/16	149,286	152,881	155,639	155,913	174,627
2016/17	150,893	154,893	157,990	157,878	178,242
2017/18	152,474	156,884	160,305	159,817	181,856
2018/19	154,031	158,856	162,589	161,728	185,430
2019/20	155,561	160,799	164,838	163,606	188,955
2020/21	157,058	162,714	167,049	165,456	192,427
2021/22	158,523	164,597	169,221	167,276	195,838
2022/23	159,955	166,452	171,355	169,065	199,181
2023/24	161,354	168,275	173,451	170,825	202,451
2024/25	162,720	170,070	175,509	172,555	205,640
2025/26	164,055	171,835	177,530	174,256	208,745
2026/27	165,358	173,570	179,513	175,926	211,763
2027/28	166,627	175,274	181,459	177,567	214,693
2028/29		176,950	183,369	179,179	217,533
2029/30			185,249	180,763	220,281
2030/31				182,325	222,939

+16,018/10 yrs

+23,261/10 yrs

+34,989/10 yrs

Figure 8.5

Residential Electric Load (GW.h)

	2007 Forecast Electric Heat	2008 Forecast Electric Heat	2009 Forecast Electric Heat	2010 Forecast Electric Heat	2011 Forecast Electric Heat
2007/08	3,300				
2008/09	3,358	3,473			
2009/10	3,413	3,538	3,505		
2010/11	3,466	3,599	3,563	3,661	
2011/12	3,506	3,659	3,624	3,717	4,157
2012/13	3,540	3,716	3,686	3,773	4,232
2013/14	3,576	3,773	3,749	3,824	4,316
2014/15	3,612	3,828	3,812	3,874	4,400
2015/16	3,647	3,882	3,876	3,925	4,487
2016/17	3,681	3,937	3,939	3,975	4,575
2017/18	3,716	3,991	4,002	4,026	4,664
2018/19	3,759	4,046	4,065	4,078	4,753
2019/20	3,805	4,100	4,127	4,129	4,841
2020/21	3,850	4,154	4,189	4,181	4,929
2021/22	3,894	4,208	4,252	4,233	5,016
2022/23	3,938	4,261	4,314	4,286	5,103
2023/24	3,981	4,314	4,376	4,339	5,188
2024/25	4,024	4,367	4,438	4,392	5,273
2025/26	4,066	4,419	4,499	4,447	5,356
2026/27	4,108	4,471	4,561	4,501	5,439
2027/28	4,150	4,523	4,622	4,556	5,520
2028/29		4,574	4,683	4,612	5,601
2029/30			4,744	4,667	5,680
2030/31				4,723	5,759

+388/10 yrs

+628/10 yrs

+859/10 yrs

Number of Residential Customers

	2007 Forecast Standard	2008 Forecast Standard	2009 Forecast Standard	2010 Forecast Standard	2011 Forecast Standard
2007/08	297,940				
2008/09	299,314	299,842			
2009/10	300,733	301,486	302,463		
2010/11	302,207	303,212	304,099	303,576	
2011/12	303,729	305,006	305,664	306,243	289,550
2012/13	305,256	306,830	307,195	308,647	291,571
2013/14	306,775	308,673	308,710	310,880	293,806
2014/15	308,274	310,529	310,213	313,105	296,032
2015/16	309,744	312,377	311,718	315,323	298,314
2016/17	311,188	314,218	313,228	317,542	300,648
2017/18	312,599	316,054	314,744	319,757	303,011
2018/19	313,974	317,881	316,263	321,970	305,381
2019/20	315,318	319,705	317,788	324,182	307,753
2020/21	316,635	321,526	319,322	326,390	310,120
2021/22	317,924	323,350	320,865	328,594	312,475
2022/23	319,188	325,173	322,418	330,793	314,813
2023/24	320,426	326,998	323,980	332,985	317,125
2024/25	321,636	328,823	325,550	335,172	319,406
2025/26	322,820	330,649	327,130	337,352	321,650
2026/27	323,976	332,476	328,717	339,526	323,853
2027/28	325,105	334,304	330,313	341,694	326,013
2028/29		336,132	331,918	343,856	328,126
2029/30			333,538	346,014	330,190
2030/31				348,175	332,203

+14,195/10 yrs

+15,201/10 yrs

+22,925/10 yrs

Residential Electric Load (GW.h)

	2007 Forecast Standard	2008 Forecast Standard	2009 Forecast Standard	2010 Forecast Standard	2011 Forecast Standard
2007/08	3,146				
2008/09	3,173	3,203			
2009/10	3,199	3,227	3,249		
2010/11	3,227	3,251	3,271	3,391	
2011/12	3,255	3,276	3,294	3,432	2,961
2012/13	3,272	3,301	3,319	3,468	2,983
2013/14	3,296	3,326	3,344	3,504	3,010
2014/15	3,323	3,351	3,370	3,543	3,037
2015/16	3,348	3,375	3,397	3,584	3,067
2016/17	3,374	3,401	3,425	3,627	3,098
2017/18	3,401	3,427	3,454	3,671	3,130
2018/19	3,429	3,454	3,484	3,717	3,163
2019/20	3,459	3,482	3,515	3,764	3,197
2020/21	3,490	3,510	3,547	3,813	3,233
2021/22	3,521	3,539	3,580	3,864	3,269
2022/23	3,552	3,569	3,615	3,917	3,305
2023/24	3,583	3,600	3,651	3,972	3,343
2024/25	3,615	3,631	3,689	4,029	3,382
2025/26	3,646	3,663	3,727	4,088	3,421
2026/27	3,678	3,696	3,767	4,149	3,461
2027/28	3,709	3,729	3,808	4,211	3,502
2028/29		3,763	3,849	4,274	3,544
2029/30			3,892	4,338	3,586
2030/31				4,404	3,630

+266/10 yrs +286/10 yrs +308/10 yrs

Please also see Manitoba Hydro's response to PUB/MH I-112(c).

Table 12 - Plug-In Electric Vehicles

PLUG-IN ELECTRIC VEHICLE FORECAST History and Forecast 2000/01 - 2030/31								
Fiscal Year	New Vehicles Purchased	New PEV Purchased	New PEV %	Total Vehicles	Total PEV	Total % PEV	Cumul Total PEV GW.h	Cumul Total PEV MW
2000/01	-	-	0.0%	615,620	-		0	0
2001/02	41,807	-	0.0%	627,110	-		0	0
2002/03	42,574	-	0.0%	638,610	-		0	0
2003/04	43,340	-	0.0%	650,100	-		0	0
2004/05	44,107	-	0.0%	661,600	-		0	0
2005/06	44,873	-	0.0%	673,090	-		0	0
2006/07	45,639	-	0.0%	684,590	-		0	0
2007/08	46,405	-	0.0%	696,080	-		0	0
2008/09	47,172	-	0.0%	707,580	-		0	0
2009/10	47,938	-	0.0%	719,070	-		0	0
2010/11	48,705	-	0.0%	730,570	30	0.0%	0	0
2011/12	49,471	100	0.2%	742,060	130	0.0%	0	0
2012/13	50,237	310	0.6%	753,560	440	0.1%	1	0
2013/14	51,003	380	0.8%	765,050	820	0.1%	2	0
2014/15	51,770	410	0.8%	776,550	1,230	0.2%	3	0
2015/16	52,536	440	0.8%	788,040	1,670	0.2%	4	1
2016/17	53,302	480	0.9%	799,530	2,150	0.3%	6	1
2017/18	54,069	530	1.0%	811,030	2,680	0.3%	7	1
2018/19	54,835	660	1.2%	822,520	3,330	0.4%	9	1
2019/20	55,601	820	1.5%	834,020	4,140	0.5%	11	1
2020/21	56,367	1,010	1.8%	845,510	5,130	0.6%	13	2
2021/22	57,134	1,290	2.3%	857,010	6,370	0.7%	16	2
2022/23	57,900	1,610	2.8%	868,500	7,900	0.9%	20	3
2023/24	58,667	2,010	3.5%	880,000	9,790	1.1%	25	3
2024/25	59,433	2,540	4.3%	891,490	12,130	1.4%	31	4
2025/26	60,199	3,180	5.4%	902,990	15,010	1.7%	38	5
2026/27	60,965	4,000	6.6%	914,480	18,560	2.0%	48	6
2027/28	61,732	5,030	8.3%	925,980	22,940	2.5%	59	7
2028/29	62,498	6,280	10.2%	937,470	28,300	3.0%	72	9
2029/30	63,265	7,850	12.6%	948,970	34,880	3.7%	89	11
2030/31	64,031	9,780	15.5%	960,460	42,920	4.5%	110	14

This table provides the estimate of the number of new vehicles and total vehicles each year in Manitoba, as well as the corresponding numbers for Plug-In Electric Vehicles. The number of retired vehicles each year is not shown. PEV MW is at Hydro's system peak.

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General Service Load Growth

Ref: PUB/MH I-118 (c)

	Mass Market (Gwh)	Mass Market growth	Top Consumers (Gwh)	Top Consumers growth	Total General Service I-118 (c) (Gwh)	Total General Service Annual Report (Gwh)	Total General Service growth
00/01	7,110		4,515		11,624		
01/02	7,084		4,818		11,903		
02/03	7,467		5,282		12,748	12,143	
03/04	7,460		5,423		12,883	13,014	
04/05	7,516		5,714		13,230	13,365	
05/06	7,587	+477/5 yrs 95/yr (6.3%)	5,948	+1433/5 yrs 285/yr (5.4%)	13,534	13,669	+1910/5 yrs 382/yr (2.9%)
06/07	7,839		5,981		13,828	13,965	
07/08	8,006		6,075		14,081	14,223	
08/09	8,049		6,065		14,114	14,256	
09/10	7,985		5,461		13,446	13,587	
10/11	8,258	+671/5 yrs 137/yr (1.7%)	5,324	-624/5 yrs -125/yr (-2.1%)	13,581	13,727	+58/5 yrs 12/yr (0.1%)
11/12	8,408		5,730		14,139	13,840	
12/13	8,566		5,951		14,517		
13/14	8,762		6,284		15,045		
14/15	8,937		6,306		15,242		
15/16	9,113	+855/5 yrs 171/yr (2.0%)	6,136	+812/5 yrs 162/yr (2.6%)	15,248		+1667/5 yrs 333/yr (2.2%)
16/17	9,278		6,191		15,478		
17/18	9,456		6,276		15,731		
18/19	9,611		6,241		15,851		
19/20	9,763		6,391		16,153		
20/21	9,914	+801/5 yrs 160/yr (1.7%)	6,551	+415/5 yrs 85/yr (1.3%)	16,465		+1217/5 yrs 243/yr (1.5%)
21/22							
22/23							
23/24							
24/05	10,502		6,951		17,452		
25/26							
26/27							
27/28							
28/29							
29/30	11,181		7,450		18,631		

Figure 8.9

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Industry Sector Load Growth Summary

Ref.: PUB/MH I-118(a)

	Chemical (GWh)	Food & Beverage (GWh)	Mining (GWh)	Misc. (GWh)	Petroleum Trans. (GWh)	Primary Metals (GWh)	Pulp & Paper (GWh)	Calculated Total Industry (GWh)	Top Consumers (GWh)
2005/06	1,853	38	38	31	863	2,237	780	5,110	5,948
2006/07	1,859	100	46	36	912	2,248	744	5,201	5,981
2007/08	1,893	107	54	46	893	2,300	766	5,273	6,075
2008/09	1,984	111	65	49	955	2,237	676	5,391	6,065
2009/10	1,968	114	67	49	915	2,033	334	5,156	5,961
2010/11	2,044	111	80	52	780	2,153	186	5,220	5,424
2011/12	2,057	107	99	51	867	2,200	172	5,381	5,531
6 year change	+204	+69	+61	+20	+4	-37	-608	+271	-417
Average Annual Change	+1.8%	+30.0%	+25.0%	+65.0%	0	-0.3%	-13.0%	-0.9%	-1.2%
	2012 Load Forecast - MIPUG/MH I-46(b)								
2012/13 to 2014/15 Growth	+157	+14	-3	+10	+289	+201	+9	+677	+576
Annual Change	+2.5%	+5.0%	-1.0%	+6.0%	+11.0%	+3.0%	+2.0%	+4.5%	+3.3%

Figure 8.10

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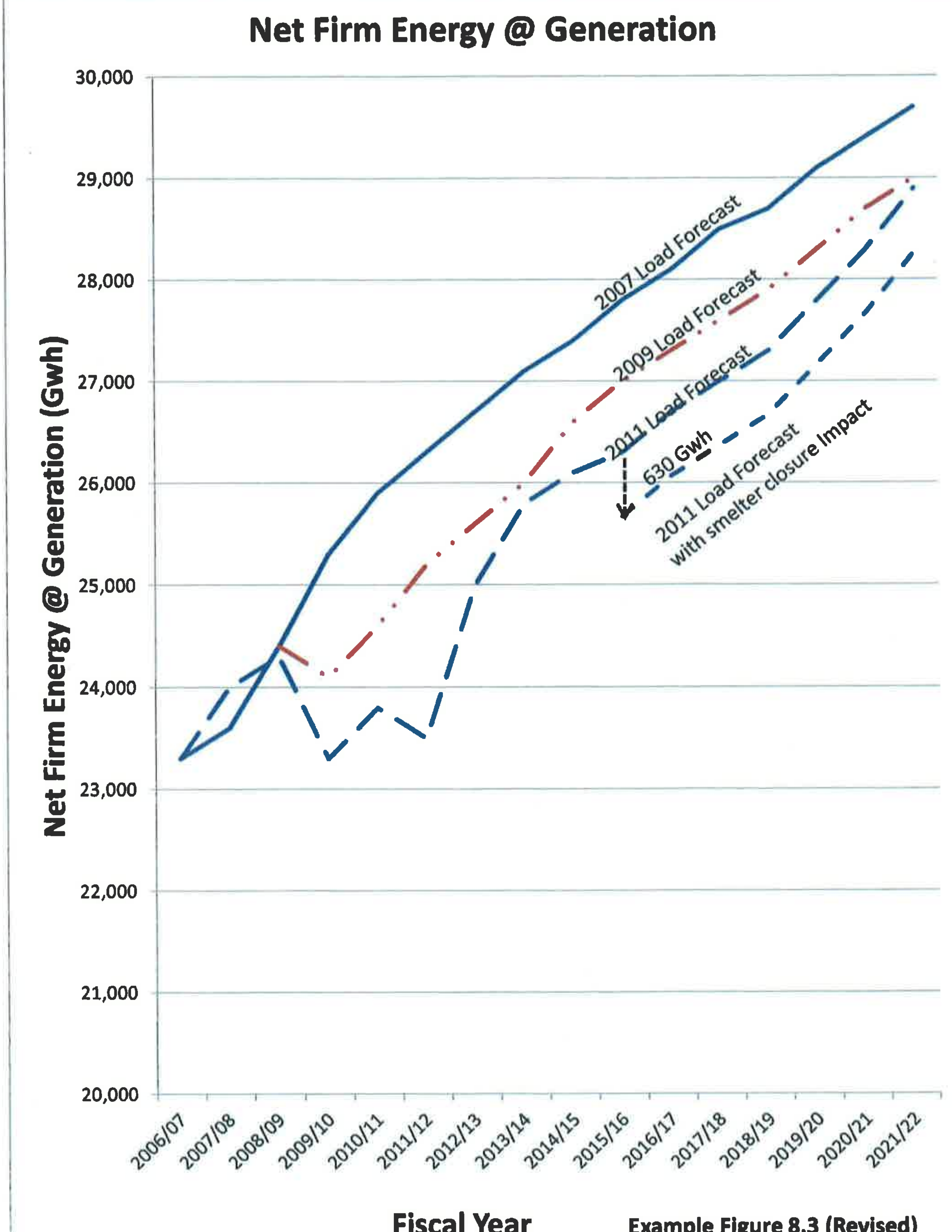

Example Figure 8.3 (Revised)

Figure 8.1

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Typical space & water heating costs

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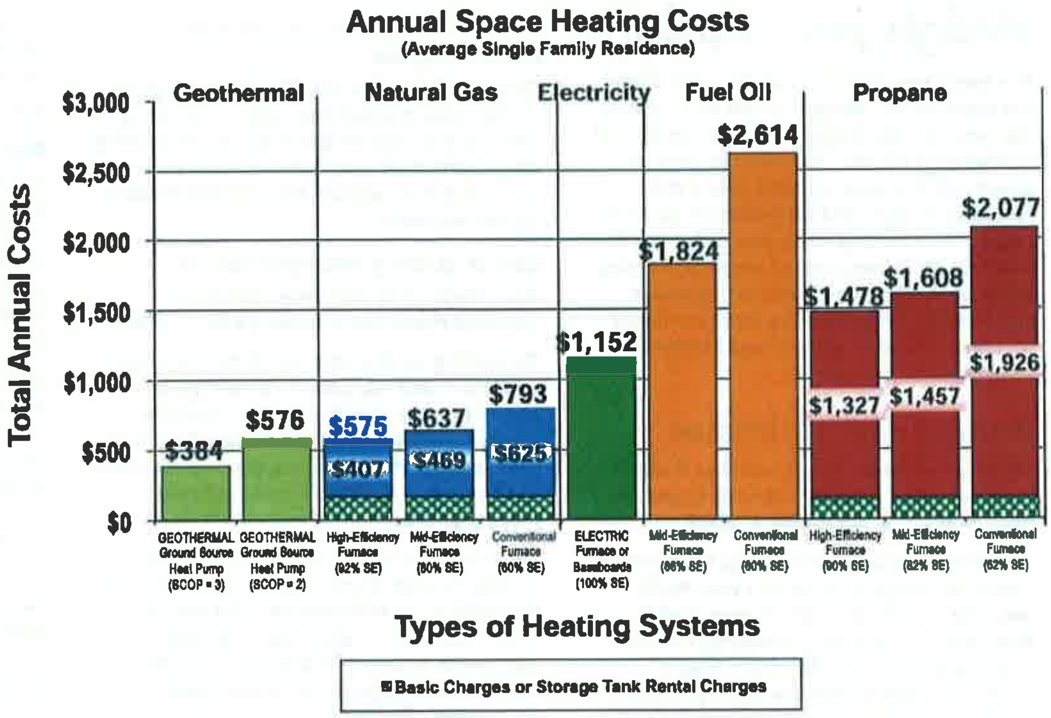
Average single family residence at rates in effect November 1, 2012

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:
$0.2336/cubic metre

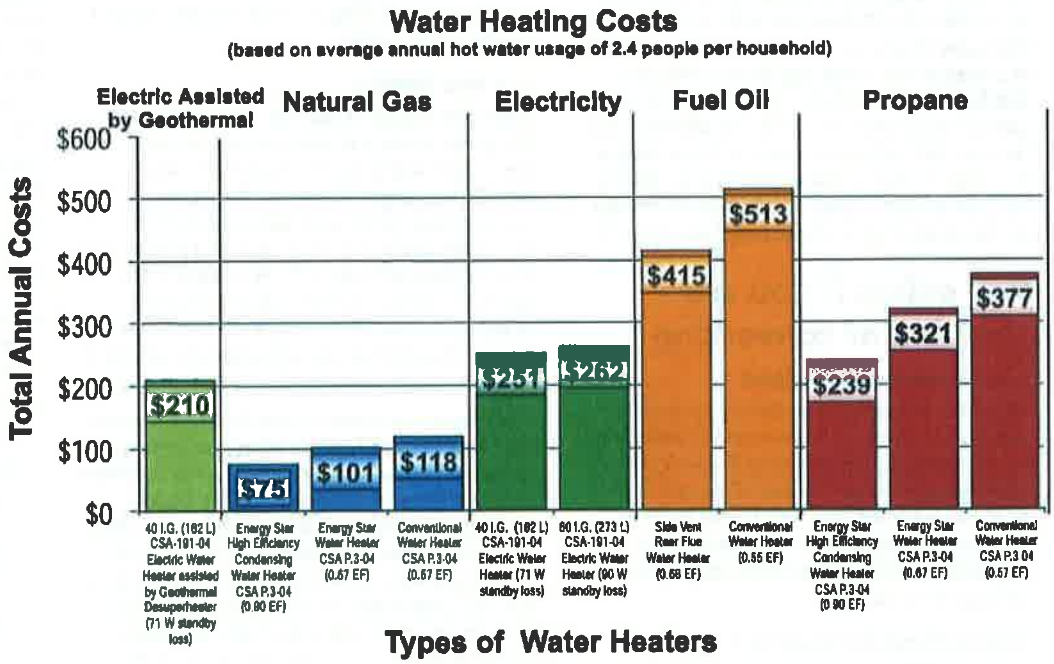
Electricity:
$0.0694/kilowatt-hour

Fuel oil:
$1.010/litre

Propane:
$0.510/litre

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

Annual propane tank rental: **$151**



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Typical space & water heating costs

Average single family residence at rates in effect November 1, 2012

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 1,200 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, 2012.

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. With Manitoba Hydro's Quarterly Rate Service, the price you pay for Primary Gas is the same price we pay for the gas in the marketplace. This rate changes every 3 months and is currently $0.0967 per cubic metre. If you buy Primary Gas on a Fixed Rate Service contract from Manitoba Hydro or a Gas Broker, you will continue to pay Manitoba Hydro for Supplemental Gas as well as transportation and distribution charges. The figure of 0.2336 per cubic metre of natural gas that we've used in the charts is known as a "re-bundled" effective rate. It includes charges for Primary and Supplemental gas, as well as for transportation and distribution of the gas on Manitoba Hydro's Quarterly Rate Service.

Key points if you are thinking of converting

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 since 1992, but many 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 existing 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 will need more than this.

Increasing the size of an electrical service usually involves changing your electrical panel or installing an additional one. An electrician should perform an electrical code load calculation to advise whether your existing service is adequate to serve the heating equipment 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.

Flue Gas Venting

When natural gas is burned, flue gases are produced which primarily contain carbon dioxide and water vapour which are not harmful to people. However, flue gases can also contain trace amounts of carbon monoxide and other gases that can present a health hazard. High-efficiency natural gas furnaces will not use the existing chimney to vent (remove) flue gases from the home. Instead they will be vented via approved plastic piping through the home's side wall or roof.

If you have a standard natural gas water heater, the Manitoba Gas Notices allow it to continue to use the existing chimney if it is in good condition and meets the requirements of the Code Authority Having Jurisdiction (Manitoba Dept. of Labour). Your heating contractor should inform you if the chimney has corroded or does not meet the code requirements. Generally, installing a new approved smaller diameter chimney liner may meet the requirements.

Issues that can arise once the natural gas water heater vents alone on the old chimney include: flue gases condensing in the chimney, or flue gas spillage into the home. If these venting problems occur, you may need to upgrade your venting system or have other work performed to rectify them. If the upgrades are costly, other options to consider are replacing the conventional heater with a side-wall vented gas water heater or an electric water heater.

Reduced chimney ventilation

Converting to electric heat or to a high-efficiency gas furnace will reduce the uncontrolled ventilation provided by the chimney. The uncontrolled chimney ventilation will be completely eliminated if you also replace your conventional gas water heater and either remove or cap off the chimney.

With a conventional gas furnace, warm moist air continuously exits the house through the chimney. This draws cold and dry replacement air into the house through cracks in walls and around windows and doors. This uncontrolled ventilation dehumidifies your home in winter, but consumes heating energy.

Reducing or eliminating this chimney ventilation can save energy but may also increase humidity levels 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 change in air leakage patterns may cause increased condensation/icing: on interior surfaces of well-sealed windows, and anywhere warm moist air leaks out of the home such as electrical outlets, between the panes of poorly sealed windows, on door seals, in door lock mechanisms and around chimney and plumbing stacks. A very small percentage of homeowners have reported experiencing some of these issues.

There is not one solution that works in every home and for every issue. Here are some of the measures that individually or in combination can minimize or eliminate the effects of reduced chimney ventilation:

- improved weatherstripping and caulking on doors and windows and other areas of air leakage (but not on storm doors)
- seasonal window insulator kits (clear heat shrink poly over inside windows and frames)
- improved windows (preferably triple pane)
- a ventilation system which may consist of:
  - exhaust fan(s)
  - exhaust fan(s) combined with a fresh air intake
  - heat recovery ventilator (HRV)

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Typical space & water heating costs

Average single family residence at rates in effect November 1, 2012

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 Electric water heating assisted by geothermal desuperheater 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 space heating with natural gas includes a basic monthly charge of $14 ($168 per year).
- SE (seasonal efficiency) is defined as the total heat output delivered by the furnace during one heating season as a percentage of the total energy input to the system. SE 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.
- Energy Factor (EF) is an overall efficiency rating of the water heater. The higher the EF, the more efficient the model. Electric water heaters are required to have maximum standby losses of 71 watts for a 40 gallon and 90 Watts for a 60 gallon.
- SCOP (Seasonal Coefficient of Performance) = 2 and = 3 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 system typically ranges from 2.0 to 3.0. For reference, the SCOP of an electric baseboard heater is 1.0. The SCOP rating accounts for cycling losses, circulating fan and pump energy and auxiliary electric heating loads which are not included in the manufacturer's COP rating of the heat pump "unit". The overall system SCOP will therefore always be significantly lower than the unit COP.

  The SCOP of a geothermal system can vary significantly and is highly dependent on the quality of the system design, installation, commissioning and ongoing maintenance practices.
- 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 0.0967 per cubic metre. Primary Gas currently comprises 90 per cent of the gas supplied (supplemental gas is 10 per cent.)
- Taxes are not included in these calculations and costs.

ENERGY RATES — in effect November 1, 2012

	Commodity charge	Heating value	
Natural gas	$0.2336/cubic metre	35,310	Btu/cubic metre
Electricity	$0.0694/kilowatt-hour	3,413	Btu/kilowatt-hour
Fuel oil	$1.010/litre	36,500	Btu/litre
Propane	$0.510/litre	24,200	Btu/litre

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Telephone / N° de téléphone : (204) 360-3946 • Fax / N° de télécopieur : (204) 360-6147
pjramage@hydro.mb.ca

September 11, 2012

Mr. H. Singh
Executive Director
Public Utilities Board
400-330 Portage Avenue
Winnipeg, Manitoba
R3C 0C4

Dear Mr. Singh:

RE: Response to Directive 17 Board Orders 116/08 and 150/08—Fuel Switching Report

In Orders 116/08 and 150/08 issued on July 29, 2008 and November 7, 2008 respectively, the Public Utilities Board of Manitoba ("PUB") provided the following Directive (#17):

> *"MH report to the Board before June 30, 2009 to whether there are greater global environmental (GHG) and economic benefits to be achieved by exporting hydraulically-generated electricity than would be achieved by fuel switching (from natural gas to electricity) and/or geothermal within Manitoba. The report should address and clearly define the relative environmental and economic benefits of these exports. The overall assumptions and impacts on the Load Forecast should also be included in the report"*

Manitoba Hydro is enclosing the Report "Economic, Load, and Environmental Impacts of Fuel Switching in Manitoba" in response to this Directive. Should you have any questions with respect to the foregoing, please do not hesitate to contact the writer at (204) 360-3946.

Yours truly,

MANITOBA HYDRO LAW DEPARTMENT
Per:

PATRICIA J. RAMAGE
Barrister and Solicitor

PJR/
encl.

7/15

Economic, Load, and Environmental Impacts of Fuel Switching in Manitoba

MANITOBA HYDRO

August 2012

Manitoba Hydro

EXECUTIVE SUMMARY

This report outlines the economic, load and environmental impacts of using electricity (including geothermal technology) instead of using natural gas for space and water heating purposes. The economic impact is assessed from the customer's and the utility's perspective along with a high level assessment of provincial leakage (i.e. the net impact of changes to extra-provincial natural gas purchases and electricity export sales). The environmental (greenhouse gas emission) impact is assessed from both a provincial and a global perspective. The scope of this assessment does not consider future uncertainty associated with a number of influential factors, including potential electricity rate structure changes (e.g. inverted rates) and potential changing Canadian and US government policies related to greenhouse gas (GHG) emissions. The assessment also does not account for any costs which may result from large-scale upgrading of Manitoba Hydro's electrical infrastructure due to significant energy demand changes.

||| Space Heating

The following table summarizes the load, economic and environmental impacts of using electricity instead of natural gas for space heating in a typical Manitoba residential home. Impacts are analyzed over the life of the equipment (i.e. 25 years). Values in brackets indicate a negative impact from an economic perspective and represent a reduction in GHG emissions from an environmental perspective.

Impact of Converting from Natural Gas to Electric Space Heat

Average Residential Home from Natural Gas to:	Electric Furnace	Geothermal (SCOP 2.5)
Annual Energy Load Impact		
Electric Load Impact (kW.h)	16,391	6,556
Natural Gas Load Impact (cu.m)	(1,776)	(1,776)
Economic Impact		
Utility Perspective (Electric)	($3,223)	($1,563)
Utility Perspective (Natural Gas)	($4,107)	($4,107)
Customer Perspective	($7,737)	($11,276)
Integrated Utility / Customer Perspective	($15,067)	($16,946)
Net Provincial Inflow (Leakage)	($6,271)	$1,061*
Annual Environmental Impact		
Manitoba (kg CO_2e/year)	(3,374)	(3,374)
US - MISO Region** (kg CO_2e/year)	0 to 12,293	0 to 4,917
Net Global**(kg CO_2e/year)	(3,374) to 8,919	(3,374) to 1,543

**The provincial inflow benefits will be offset by higher cost of geothermal units relative to the cost of natural gas furnaces and air conditioners (i.e. estimated at $2,000 to $3,000).*

***The US-MISO Region and Net Global impacts are shown as a range, which includes the impact under today's emission policies in export regions and recognizes what the potential impacts could be under more aggressive emission policies in export regions.*

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From the customer, utility and provincial leakage perspectives, there are substantive benefits when customers use natural gas rather than electricity for space heating purposes. The directional impact for each of these factors are also the same when using natural gas for space heating relative to using geothermal systems, except for the provincial leakage impact. In the latter case, a more complete analysis would need to account for the higher cost of geothermal furnace units which are imported into Manitoba relative to the cost of importing natural gas furnaces and air conditioners.

Using electricity for space heating in Manitoba as opposed to natural gas will reduce GHG emissions in Manitoba; however the global GHG emissions will be higher due to reduced electricity exports from Manitoba (i.e. electricity exports would no longer displace fossil generation). In the future, the global impacts may change depending on future environmental policies (e.g. if a cap on GHG emissions was introduced within the U.S. in the future, changes in Manitoba electricity exports would potentially have no incremental impact on US GHG emissions). Given the possible future outcomes, the US and global environmental impacts are shown as a range of possible outcomes.

||| Water Heating

The following table summarizes the impact of using electricity instead of natural gas for water heating applications in a typical Manitoba residential home, analyzed over the life of the equipment (i.e. 10 years). Values in brackets indicate a negative impact from an economic perspective and represent a reduction in GHG emissions from an environmental perspective. The impacts are assessed for using electric hot water tanks relative to a conventional natural gas unit.

Impact of Converting from Natural Gas to Electric Water Heat

Average Residential Home from:	Conventional Gas to Electric Water Heat
Annual Energy Load Impact	
Electric Load Impact (kW.h)	3,489
Natural Gas Load Impact (cu.m)	(491)
Economic Impact	
Utility Perspective (Electric)	($10)
Utility Perspective (Natural Gas)	($317)
Customer Perspective	($727)
Integrated Utility / Customer Perspective	($1,054)
Net Provincial Inflow (Leakage)	($297)
Annual Environmental Impact	
Manitoba (kg CO_2e/year)	(933)
US - MISO Region* (kg CO_2e/year)	0 to 2,617
Net Global* (kg CO_2e/year)	(933) to 1,684

**The US-MISO Region and Net Global impacts are shown as a range, which includes the impact under today's emission policies in export regions and recognizes what the potential impacts could be under more aggressive emission policies in export regions.*

Similar to space heating, there are benefits to using natural gas relative to electricity for water heating purposes. The environmental (GHG) impacts of using electricity rather than natural gas for water heating applications are similar to space heating however the impacts are much lower on a per unit basis as the equipment uses less electricity/natural gas.

||| Manitoba - Fuel Choice Trends & Impacts

A trend towards more customers using electricity for space and water heating is evident in Manitoba. For water heating, a trend toward the increased use of electric water heaters is currently taking place and is forecast to continue into the future. For example, virtually 100% of the new home market is installing electric water heaters. A small shift towards the increased use of electricity for space heating is expected however this shift has been declining due primarily to the continuation of low natural gas prices.

As indicated in the following table, the impact of fuel switching from natural gas to electricity is approximately 3% of the expected 2030/31 domestic electric demand for both space and water heating and a 5% reduction in the provincial natural gas demand forecast in 2030/31.

2011 Load Forecast	Portion of 2011 Forecast Attributed to Fuel Switching 2030/31		
	Total Load Forecast	Space & Water Heating	% of Load
Net Firm Energy (GW.h)	32,465	874	3%
Total Natural Gas Sales ($10^6 m^3$)	1,924	-103	-5%

There are substantive economic impacts from the increased use of electricity (i.e. fuel switching) for heating purposes based on Manitoba Hydro's 2011 energy forecasts. The following table presents the net economic costs to the utility and to customers over a 30 year period. In addition, reduced export power revenue is not fully offset by the reduced imported natural gas purchases and is therefore expected to result in lower net provincial cash inflows.

Net Economic Costs & Provincial Leakage

2011 Forecast	Net Cost
Utility Perspective (Electric)	$132 million
Utility Perspective (Natural Gas)	$69 million
Customer Perspective	$311 million
Electricity Export Revenues	$505 million
Natural Gas Import Purchases	($251 million)
Net Provincial Leakage	$254 million

The following table provides the environmental (GHG) impact of fuel switching in space and water heating as per the 2011 forecasts.

Potential Annual GHG Impacts
(Attributed by Region due to Energy Use)

Year	Manitoba (tonnes C02e / year)	US - MISO Region* (tonnes C02e / year)	Net Global Impact* (tonnes C02e / year)
2012/13	(11,970)	38,753	26,783
2022/23	(154,166)	0 to 496,268	(154,166) to 342,102
2032/33	(203,699)	0 to 687,473	(203,699) to 483,774

** The US-MISO Region and Net Global impacts are shown within a range, which includes the impact under today's emission policies in export regions and potentially what the impacts would be under more aggressive emission policies in export regions.*

||| Hypothetical Impact of Total Conversion

The following analysis provides insight into the hypothetical maximum load impacts if all customers in Manitoba replaced their existing space and water heating equipment with an alternative natural gas, electric or geothermal system. The results simply provide a technical range of hypothetical impacts in terms of electricity and natural gas demand in Manitoba. The table provides:

- the existing electricity and natural gas load for space and water heating in Manitoba; and
- the hypothetical potential electricity and natural gas loads under extreme fuel conversion scenarios (i.e. all customers immediately fuel switch to either all natural gas use, all electric use or all geothermal use for space and water heating purposes).

Impacts are based on the electric and natural gas forecast for 2011.

Hypothetical Annual Load Impact
If All Customers in Manitoba Immediately Switched to One Type of Heating Fuel

	Natural Gas (1000 m3)	Electricity (GW.h)	Geothermal SCOP 2.5 (GW.h)
Current load situation - space heat	**938,723**	**3,473**	**67**
Current load situation - water heat	**194,925**	**1,097**	**0**
A. Immediate fuel switch to natural gas - space	1,339,429	---	---
A. Immediate fuel switch to natural gas - water	349,251	---	---
B. Immediate fuel switch to electric - space	---	11,341	67
B. Immediate fuel switch to electric - water	---	2,482	---
C. Immediate switch to geothermal - space	---	---	4,603
C. Immediate switch to geothermal - water	---	---	2,081

The magnitude of the hypothetical potential impact of all customers switching to electric space and water heating would add 7,868 GWh and 1,385 GWh respectively of annual electric load in Manitoba. Combined, this additional electric load would be equivalent to approximately two generating stations the size of Conawapa. **It is important to recognize that the implications to the utility go beyond the analysis provided within this report.** The consequence of a significant fuel switching scenario would also require a substantial investment in additional generation, transmission and distribution infrastructure. In addition, the utility would be confronted with managing a more diverse winter/summer load.

From the natural gas perspective, the remaining annual natural gas load would be 40% of the existing load and as such, the scenario would require a rate increase to the remaining natural gas customers to cover fixed costs (i.e. the fixed costs would need to be recovered from a much smaller customer base). It should be noted that the theoretical potential impact of all customers switching to natural gas space and water heating is also not possible with today's natural gas infrastructure. The implications of this theoretical scenario would also require extensive new infrastructure at an extraordinarily high cost.

The potential impacts of fuel switching in Manitoba for space and water heating can be significant. Given the economic drivers from a customer's perspective, it is unlikely that the Manitoba market will experience any overwhelming shift in space heating from natural gas to electricity, provided customers are informed on their choices. With water heating, the drivers are substantial enough that Manitoba Hydro expects to see a continued market shift from natural gas to electricity.

Manitoba Hydro recognizes the value customers place on having choice and the Corporation does not intend on mandating a specific fuel be used for space and water heating. Where appropriate, the Corporation prefers to use market intervention mechanisms (e.g. education, direct financial incentives, rate design options, etc.) to influence the market.

8.0 Conclusions

The following table summarizes the impact of using electricity instead of natural gas for space and water heating in a typical residential home. The economic impact to the customer includes the incremental cost of installing electric instead of natural gas heating equipment in new homes and existing homes. The economic impact is taken over the life of the equipment[8], whereas energy and environmental (GHG) impacts are shown on an annual basis.

Impact of Fuel Switching
Average Residential Home

	Gas to Electric Furnace	Gas to Geothermal (SCOP 2.5)	Conventional Gas to Electric Water Heat
Annual Energy Load Impact			
Electric Load Impact (kW.h)	16,391	6,556	3,489
Natural Gas Load Impact (cu.m)	(1,776)	(1,776)	(491)
Economic Impact (NPV over the life of the equipment)			
Utility Perspective (Electric)	($3,223)	($1,563)	($10)
Utility Perspective (Natural Gas)	($4,107)	($4,107)	($317)
Customer Perspective - Remaining Natural Gas Service	($9,146)	($12,685)	($727)
Customer Perspective - No Remaining Natural Gas Service	($7,737)	($11,276)	n/a
Integrated Utility / Customer Perspective	($15,067)	($16,946)	($1,054)
Net Provincial Cash Inflow (Leakage)	($6,271)	$1,061*	($297)
Annual Environmental Impact			
Manitoba (kg CO_2e / year)	(3,374)	(3,374)	(933)
US - MISO Region** (kg CO_2e / year)	0 to 12,293	0 to 4,917	0 to 2,617
Net Global** (kg CO_2e / year)	(3,374) to 8,919	(3,374) to 1,543	(933) to 1,684

**The provincial inflow benefits will be offset by higher cost of geothermal units relative to the cost of natural gas furnaces and air conditioners (i.e. estimated at $2,000 to $3,000).*
***The US-MISO Region and Net Global impacts are shown as a range, which includes the impact under today's emission policies in export regions and recognizes what the potential impacts could be under more aggressive emission policies in export regions.*

Overall, from the customer, utility, provincial leakage and global environmental perspectives, there are substantial benefits when customers use natural gas for space heating purposes. The directional impact for each of these factors is the same for using natural gas for space heating relative to using geothermal systems, except when considering provincial leakage impacts; however in the latter case, a more complete analysis would need to account for the higher cost geothermal furnace units which are imported into Manitoba relative to the cost of importing natural gas furnaces/air conditioning units (note geothermal units are estimated to cost $2000 - $3000 more). For water heating, the directional impact is the same as space heating. As a cautionary note, it should be recognized that this analysis is

[8] Space heating equipment is assumed to have a 25 year life, whereas water heating equipment is assumed to have a 10 year life.

using average cost estimates. Capital costs (i.e. quoted installation prices) can vary greatly in the market place and actual customer specific situations will vary considerably.

Electric Business Perspective
Manitoba Hydro's electric operations are better positioned economically when a consumer uses natural gas for space and water heating purposes as the utility's marginal costs (export revenues and avoided infrastructure costs) are higher than the domestic revenue realized through the sale of electricity in Manitoba. The value to the Corporation is $3,223 for each conventional space heating application, $1,563 for each geothermal application and $10 for each water heating application.

Natural Gas Business Perspective
Manitoba Hydro's gas operations are better positioned economically when a consumer uses natural gas for space and water heating purposes as the utility collects additional revenue from its customers through its fixed charges and distribution charges (assuming rates for these services remain unchanged). Primary Gas costs are a "pass through" cost and therefore, have no impact on the natural gas business. For this analysis, transportation costs are also considered a "pass through" cost as it is assumed that Manitoba Hydro could avoid these costs if customers reduced their use of natural gas. The value to the Corporation is $4,107 for each space heating system and $317 for each water heating system over the life of the equipment.

Customer Perspective
Caution must be exercised in reviewing the analysis from a customer's perspective due to the wide range of installation costs charged by industry for installing space and water heating systems. In addition, this analysis is for first time or conversion costs associated with installing a natural gas water heater.

For the purpose of this analysis and based on average costs, a customer is:

- $7,737 better off by installing a natural gas space heating system relative to a conventional electric furnace;
- $11,276 better off by installing a natural gas space heating system relative to a geothermal system achieving an average SCOP of 2.5; and
- $727 better off by installing a conventional natural gas water heater relative to an electric water heater.

Provincial Leakage
Over the life of the equipment, net provincial cash inflows are reduced by $6,271 and $297 respectively, when electric systems are used for space and water heating as compared to using a natural gas furnace or conventional gas hot water tank. Relative to using natural gas, using geothermal systems for space heating increases provincial cash inflows by $1,061 over 25 years.

Environmental (GHG) Impacts
Relative to using natural gas, using electricity for space and water heating in Manitoba will reduce provincial GHG emissions. Impacts on global GHG emissions, however, are less certain. In the short term, and potentially in the longer term, global GHG emissions will be increased due to reduced electricity exports from Manitoba under existing environmental policies. Manitoba's electricity exports replace fossil generation in export regions, thereby reducing more global GHG emissions than could be reduced provincially through less natural gas use. In the longer term, however, global impacts are less certain

and will depend on environmental policies at the time. For example, fewer electricity exports from Manitoba would not necessarily result in an increase to GHG emissions in an export region that imposed a GHG emissions cap. With lower electricity exports from Manitoba, the export region may need to take alternative action to ensure that emissions do not exceed an established cap. Manitoba's electricity may be just one of a number of other possible options for meeting that cap.

Market Trends

For water heating, a trend towards increased use of electric water heaters has been evident and is forecast to continue into the future. The new home market is effectively 100% transformed, with almost all new homes located within natural gas serviced areas now being constructed without chimneys and using electric hot water heaters. This shift from using natural gas water heaters is being driven primarily by economics, as the cost of installing natural gas water heaters has risen substantially due to new designs incorporating safety measures and due to the adoption of more energy efficient side-vented hot water tanks. In addition to the increased capital cost of natural gas hot water tanks, the gap in operating costs between an electric and natural gas hot water tank narrowed substantially during the past decade due to increased natural gas prices. More recently natural gas prices have fallen dramatically and the price gap in operating costs is again widening, The impact on customer preferences for natural gas hot water tanks at this time are uncertain; however, it is doubtful that homebuilders will be promoting the use of natural gas hot water heaters due to the higher capital cost associated with these units.

For space heating, a slight trend towards more customers using electricity has been observed. This trend was reflected in Manitoba Hydro's 2011 Energy Forecasts where a drop of approximately 3% in the use of natural gas for space heating is forecast.

Discussion

The potential impacts of fuel switching in Manitoba for space and water heating can be significant and the Corporation is monitoring market trends very closely. Given the economic drivers from a customer's perspective, it is unlikely that the Manitoba market will experience any overwhelming shift in space heating from natural gas to electricity, provided customers are informed on their choices. With water heating, the drivers are substantial enough that Manitoba Hydro expects to see a continued market shift from natural gas to electricity.

Manitoba Hydro recognizes the value customers place on having choice and the Corporation does not intend on mandating a specific fuel be used for space and water heating. Where appropriate, the Corporation prefers to use market intervention mechanisms (e.g. education, direct financial incentives, rate design options, etc.) to influence the market.

Electric Vehicles

The Plug-In Electric Vehicle (PEV) forecast for 2030/31 has been reduced from 195 GW.h in the 2010 forecast to 110 GW.h in this year's forecast. They would use 14 MW at winter peak.

Comparison to the 2010 Forecast

The Gross Firm Energy starts off down 124 GW.h in 2011/12 but is up the next three years. It is again down for the next five years due to the expected drop of load from a Top Consumer. By 2030/31 it is up 331 GW.h from the 2010 forecast. This is equivalent to 3/4 of a year of load growth (1 year = 432 GW.h).

Changes observed in the 2011 Forecast over the 2010 Forecast (and the 2030/31 effect):

1. Residential Basic forecast (+263 GW.h)
2. General Service Mass Market forecast (+705 GW.h)
3. General Service Top Consumers forecast (-613 GW.h)
4. Other Sales and Losses (-24 GW.h)

The Gross Total Peak starts down 47 MW in 2011/12 and remains down for the next four years. After that, the forecast is up and by 2030/31 is 129 MW higher than the 2010 forecast. This is equivalent to over 1 1/2 years of peak load growth (1 year = 80 MW).

Unexpected Potential Loads

These events are not expected within the next 20 years. They are listed so their effects can be considered if the need arises.

	Effect (GW.h)	Effect (MW)
Converting Diesel Customers to the Integrated System	+40	+9
Climate Change per Degree Celsius Warmer	+100	-40
2 Modest Size Server Farms	+200	+24
One New Very Large Industrial Customer	+1,500	+180
One Less Very Large Industrial Customer	-1,500	-180
Additional Load if Electric Vehicles Grow to 70%	+1,610	+201
Increased Residential Use of Electricity for Space heat	+814	+265
Increased Residential Use of Electricity for Water heat	+393	+45

A probability-based estimate that includes variation due to economics and all scenarios for 2030/31 gives a 10% chance that the Gross Energy requirement is greater than 35,394 GW.h and a 10% chance that it is less than 29,537 GW.h. The variation is plus or minus 2,929 GW.h.

8

Recommended Plan

Page 1 of 2

System Firm Energy Demand and Dependable Resources (GW.h)

2011 Base Load Forecast, 2011 DSM - Option 2

Kelsey Rerunnering, Pointe du Bois rebuild 2030/31, Brandon Unit 5 until 2018/19, Wuskwatim 2011/12, Bipole III Line (West) 2017/18
Supply Includes: Keeyask 2019/20, Conawapa 2024/25, SCGT's starting in 2041/42, 500kV interconnection in 2019/20
Demand Includes: Potential Sales to Wisconsin Public Service and Minnesota Power

Fiscal Year	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	2025/26	2026/27	2027/28	2028/29
Power Resources																		
Existing Manitoba Hydro Plants	20740	20720	20700	20690	20660	20660	20640	20630	20610	20600	20590	20580	20580	20570	20560	20560	20550	20540
Hydro Adjustment	340	340	340	340	240	240	240	240	240	240	240	240	240	240				
Existing Hydro NET	21080	21060	21040	21030	20920	20900	20880	20870	20850	20840	20830	20820	20820	20810	20560	20560	20550	20540
New Hydro																		
Wuskwatim	75	1205	1250	1250	1250	1250	1250	1250	1250	1250	1250	1250	1250	1250	1250	1250	1250	1250
Conawapa														2151	4550	4550	4550	4550
Keeyask									677	2898	2903	2903	2903	2903	2903	2903	2903	2903
Supply Side Enhancement Projects																		
Kelsey Rerunnering																		
Pointe du Bois Rebuild																		
Bipole III HVDC Line NET							243	243	243	258	258	258	258	258	162	162	162	162
Manitoba Thermal Plants																		
Brandon Unit 5	811	811	811	811	811	811	811	811										
Selkirk Gas	953	953	953	953	953	953	953	953	953	953	953	953	953	953	953	953	953	953
Brandon Units 6-7 SCGT	2354	2354	2354	2354	2354	2354	2354	2354	2354	2354	2354	2354	2354	2354	2354	2354	2354	2354
New Thermal Plants																		
SCGT																		
Committed Wind	770	819	819	819	819	819	819	819	819	819	819	819	819	819	819	819	819	819
New Wind																		
Demand Side Management	183	293	411	508	608	696	699	774	830	882	911	944	971	996	1009	967	947	924
Imports																		
Contracted Energy Imports	2705	2705	2705	2705	1609	1614	1614	1614	1614	2527	2710	2710	2710	2710	1363	1096	1096	1096
Proposed Energy Imports															1460	1753	2118	2192
Non-Contracted Energy Imports					1100	1100	1100	1100	1100	1100	1100	1100	1100	1100	1446	1575	1575	1575
Total Power Resources	28931	30200	30343	30430	30424	30497	30723	30788	30890	33881	34088	34111	34138	36304	38830	38942	39277	39318
Demand																		
2011 Base Load Forecast	24615	25173	25930	26284	26406	26794	27205	27481	27966	28462	28887	29311	29733	30153	30570	30964	31396	31801
Non-Committed Construction Power			10	25	50	60	85	105	80	75	55	80	100	90	40	25	30	30
Exports																		
Current Exports	3564	3293	3156	3156	2115	2012	2012	2012	2012	3064	3695	3780	3780	3780	2017	1913	1492	1408
Proposed Exports															1683	2020	2441	2525
Less Adverse Water	-91	-91			-309	-370	-370	-370	-370	-370	-370	-370	-370	-370	-61			
Total Demand	28108	28374	29096	29465	28263	28495	28931	29227	29687	31230	32267	32801	33242	33653	34249	34942	35359	35764
System Surplus	823	1826	1246	965	2162	2002	1792	1561	1003	2651	1821	1310	895	2651	4581	4000	3918	3554
Less: Brandon Unit 5	811	811	811	811	811	811	811	811										
Adverse Water Energy	91	91			309	370	370	370	370	370	370	370	370	370	61			
Exportable Surplus		924	435	154	1042	821	610	380	633	2281	1451	939	525	2260	4520	4000	3918	3554

Recommended Plan

System Supply & Demand Balance (GW.h) at North

Under Average of all Flow Conditions

2011 Base Load Forecast, 2011 DSM - Option 2

Kelsey Rerunnering, Pointe du Bois rebuild 2030/31, Wuskwatim 2012/13, Bipole III Line 2017/18 (West)

Supply Includes: Keeyask 2019/20, Conawapa 2024/25, SCGTs starting in 2041/42, 500kV Interconnection in 2019/20

Demand Includes: Potential Sales to Wisconsin Public Service and Minnesota Power

Fiscal Year	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30
Power Resources																	
Hydro Generation	30744	30711	30693	30698	30460	30376	30813	33223	34587	34816	34757	36491	40442	41710	41676	41636	41637
Bipole III					392	392	392	315	315	315	315	315	27	27	27	27	27
Thermal Generation	341	359	343	355	416	457	324	338	330	340	337	334	276	289	307	302	304
Committed Wind	963	963	963	963	963	963	963	963	963	963	963	963	963	963	963	963	963
Demand Side Management	411	508	608	696	699	774	830	882	911	944	971	996	1009	967	947	924	911
Imports	1420	1516	1494	1542	1625	1673	1937	1923	1791	1818	1953	1902	1856	2042	2160	2232	2307
Total Power Resources	33878	34058	34100	34254	34554	34635	35259	37645	38898	39195	39295	41000	44573	45998	46080	46083	46148
Demand																	
2011 Base Load Forecast	25930	26284	26406	26794	27205	27481	27966	28462	28887	29311	29733	30153	30570	30984	31396	31801	32208
Non-Committed Construction Power	10	25	50	60	85	105	80	75	55	80	100	90	40	25	30	30	35
Current Exports (with MP 250 MW sale)	3307	3307	2265	2161	2161	2161	2161	3500	4139	4213	4213	4213	2081	1902	1902	1902	1737
Proposed Exports													2142	2571	3107	3214	3214
Total Demand	29247	29616	28721	29015	29451	29747	30207	32036	33081	33605	34046	34456	34833	35482	36435	36947	37194
Exportable System Surplus	4630	4442	5379	5239	5103	4888	5052	5608	5817	5590	5249	6544	9740	10515	9645	9136	8954

Fiscal Year	2030/31	2031/32	2032/33	2033/34	2034/35	2035/36	2036/37	2037/38	2038/39	2039/40	2040/41	2041/42	2042/43	2043/44	2044/45	2045/46	2046/47
Power Resources																	
Hydro Generation	41837	41908	41938	41940	41935	41917	41927	41932	41929	41936	41926	41931	41924	41923	41935	41941	41911
Bipole III	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27
Thermal Generation	304	303	304	302	302	261	243	219	192	168	157	246	340	453	568	688	724
Commited Wind	963	963	963	963	963	963	963	963	963	963	963	963	963	963	963	963	963
Demand Side Management	894	889	889	888	885	887	878	868	858	858	858	858	858	858	858	858	858
Imports	2344	2398	2446	2505	2562	2478	2465	2530	2547	2493	2596	2663	2751	2824	2822	2881	3011
Total Power Resources	46388	46488	46567	46624	46675	46533	46504	46538	46514	46444	46536	46687	46862	47048	47173	47357	47492
Demand																	
2011 Base Load Forecast	32608	33009	33409	33809	34209	34610	35010	35410	35811	36211	36611	37012	37412	37812	38213	38613	39013
Non-Committed Construction Power	30	10															
Current Exports (with MP 250 MW sale)	1704	1704	1704	1704	1704	365	97	97	97	97	97	97	97	97	97	97	97
Proposed Exports	3214	3214	3214	3214	3214	3214	2679	2036	1125	161							
Total Demand	37557	37937	38327	38726	39128	38190	37786	37543	37033	36469	36708	37109	37509	37909	38310	38710	39110
Exportable System Surplus	8811	8551	8239	7896	7547	8343	8718	8995	9481	9975	9828	9578	9354	9139	8863	8648	8382

CAC/MH I-3 (Revised)

Subject: **Summary & Reasons for Application**
Reference: **Tab 2, Page 3 (lines 7-13), Tab 4, Page 3 (lines 29-32), Attachment 5 (filed July 2012)**

a) **Please provide Tables in the same format as Attachment 5 that that set out the values for 2009/10 through 2019/20 based on:**

- **IFF09-1**
- **IFF10-2 (for 2009/10 please show actual results)**
- **IFF11-2 (revise current table to include 2010/11 actual values and 2011/12 forecast values)**

ANSWER:

Please see the attached schedules.

Note that the forecast US export sales average price calculation from 2011/12 to 2019/20 includes net transmission charges and credits. Please see the response to MIPUG/MH I-12(b) for details of the transmission charges and credits. On an actual basis, transmission charges and credits cannot be directly attributed to the different categories of sales and are not included in the calculations for actual information from 2007/08 to 2011/12 as a result.

AVERAGE PRICE CALCULATION: IFF11-2

VOLUMES (In GW.h)	ACTUAL 2007/08	ACTUAL 2008/09	ACTUAL 2009/10	ACTUAL 2010/11	ACTUAL 2011/12	FORECAST -> 2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20
Demand:														
Manitoba Domestic Energy Sales	21061	21210	20486	20786	20770	21147	21749	22261	22488	22523	22796	23173	23351	23728
Domestic energy Losses	3102	3280	3012	3195	2975	3496	3161	3181	3223	3237	3272	3022	3061	3100
Firm & Opportunity Export Sales to Canada	482	417	373	905	886	804	915	589	577	603	595	581	570	537
Firm & Opportunity Export Sales to US	10539	9709	10487	9439	9358	9440	6337	6537	6378	6257	6048	5853	5673	5845
Export Transmission Losses	986	893	928	909	883	876	625	654	632	624	600	575	554	555
Total Demand Volumes:	**36170**	**35509**	**35286**	**35234**	**34872**	**35763**	**32787**	**33222**	**33299**	**33244**	**33311**	**33204**	**33209**	**33767**
Supply:														
MH Hydraulic Generation	34897	34193	33818	34036	33158	33158	29268	30744	30712	30693	30699	30461	30375	30813
MH Thermal Generation	457	335	143	66	77	77	111	311	328	314	332	385	430	295
Purchased Energy	816	981	1325	1132	1637	2530	3497	2259	2350	2328	2371	2449	2495	2751
Total Supply Volumes:	**36170**	**35509**	**35286**	**35234**	**34872**	**35765**	**32876**	**33313**	**33390**	**33335**	**33402**	**33296**	**33300**	**33858**
REVENUE/COST (In millions of dollars)														
Manitoba Domestic Energy Sales @ Approved Rates	1,074.583	1,126.812	1,144.891	1,200.381	1,191.117	1,186.223	1,290.384	1,293.566	1,306.475	1,313.103	1,329.744	1,349.664	1,361.356	1,381.890
Additional Domestic Revenue	0.000	0.000	0.000	0.000	0.000	0.000	45.260	105.523	156.033	208.272	264.834	325.447	387.404	455.377
Total Manitoba Domestic Energy Sales	1074.583	1126.812	1,144.891	1,200.381	1,191.117	1,186.223	1,335.644	1,399.089	1,462.508	1,521.375	1,594.578	1,675.111	1,748.760	1,837.267
Total Export Sales to Canada	38.525	45.389	40.971	35.728	34.416	30.020	33.720	25.704	30.824	37.390	41.398	44.821	47.780	48.654
Total Export Sales to USA	499.137	469.755	341.312	317.638	292.325	270.237	221.081	277.149	320.013	386.869	415.481	439.948	458.828	513.945
Total Export Sales	537.662	515.144	382.283	353.366	326.741	300.257	254.801	302.852	350.838	424.259	456.879	484.769	506.608	562.599
MH Hydraulic Generation	117.006	114.549	114.022	114.122	110.848	110.837	97.834	102.715	102.608	102.546	102.564	101.771	101.482	102.945
MH Thermal Generation	15.358	13.578	8.438	5.403	9.323	9.323	9.386	21.929	25.643	25.530	28.061	34.026	40.391	36.076
Purchased Energy	34.885	56.309	32.074	34.676	78.079	83.914	120.044	108.483	120.490	125.566	133.687	143.093	151.183	167.962
AVERAGE PRICE ($/MW.h))														
Manitoba Domestic Energy Sales @ Approved Rates	$ 51.02	$ 53.13	$ 55.89	$ 57.75	$ 57.35	$ 56.10	$ 59.33	$ 58.11	$ 58.10	$ 58.30	$ 58.33	$ 58.24	$ 58.30	$ 58.24
Additional Domestic Revenue	-	-	-	-	-	0.00	2.08	4.74	6.94	9.25	11.62	14.04	16.59	19.19
Total Manitoba Domestic Energy Sales @ meter	$ 51.02	$ 53.13	55.89	57.75	57.35	56.10	61.41	62.85	65.04	67.55	69.95	72.29	74.89	77.43
Total Export Sales to Canada	48.03	49.46	33.99	27.76	29.65	37.34	36.85	43.66	53.39	62.03	69.62	77.14	83.81	90.54
Total Export Sales to USA	47.33	48.83	32.95	33.71	31.23	28.63	34.89	42.40	50.17	61.83	68.70	75.17	80.88	87.92
Total Export Sales	47.36	48.85	32.99	33.31	31.10	29.31	35.14	42.50	50.44	61.85	68.78	75.34	81.14	88.14
MH Hydraulic Generation	$ 3.35	$ 3.35	$ 3.37	$ 3.35	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34
MH Thermal Generation	33.61	40.53	59.01	81.86	121.08	121.08	84.56	70.61	78.22	81.42	84.54	88.28	93.91	122.44
Purchased Energy	48.85	48.56	31.58	36.71	47.33	33.17	34.33	48.03	51.26	53.93	56.37	58.43	60.59	61.06

PUB/MH I-11

Reference: 2012 GRA Tab 9 P. 16-19

a) Please refile the information in 2012 GRA Tab 9 (P.18) and provide unit price calculations for the entire period since 2000/01.

ANSWER:

Please see tables below.

	TOTAL SALES								
	DEPENDABLE SALES			OPPORTUNITY SALES			SYSTEM MERCHANT SALES		
	GWh	CAD $M	AvgPrice	GWh	CAD $M	AvgPrice	GWh	CAD $M	AvgPrice
2000/01	6,352	258	40.64	5,801	217	37.39	0	0	0
2001/02	6,277	322	51.65	6,022	281	46.63	0	0	0
2002/03	6,544	339	53.37	3,191	137	42.97	0	0	0
2003/04	6,231	295	48.46	735	52	48.46	11	0.5	44.43
2004/05	5,633	290	51.44	4,798	239	51.44	315	11	33.32
2005/06	4,044	240	59.25	10,303	510	47.73	919	63	60.07
2006/07	3,654	218	59.67	6,250	295	46.53	1,206	60	43.38
2007/08	3,921	209	53.22	7,099	328	44.42	1,262	72	49.17
2008/09	4,087	233	57.12	6,039	287	43.64	1,598	86	48.08
2009/10	3,263	186	56.99	7,597	184	22.98	775	26	28.29
2010/11	3,377	172	51.09	6,967	181	24.77	712	28	36.93
2011/12	3,742	175	46.79	6,502	152	22.18	436	17	31.10

	TOTAL U.S. SALES								
	U.S. DEPENDABLE SALES			U.S. OPPORTUNITY SALES			U.S. SYSTEM MERCHANT SALES		
	GWh	CAD $M	AvgPrice	GWh	CAD $M	AvgPrice	GWh	CAD $M	AvgPrice
2000/01	4,895	199	40.69	4,511	167	36.95	0	0	0
2001/02	4,767	263	55.15	5,083	247	48.66	0	0	0
2002/03	4,947	277	56.09	2,713	115	42.30	0	0	0
2003/04	5,245	259	49.45	507	35	69.42	0	0	0
2004/05	5,633	290	51.44	3,218	171	54.48	109	1	10.64
2005/06	4,044	240	59.25	8,879	401	45.12	0	0	0
2006/07	3,654	218	59.67	5,877	270	46.24	0	0	0
2007/08	3,921	209	53.22	6,618	289	44.19	0	0	0
2008/09	4,087	233	57.12	5,622	237	43.24	0	0	0
2009/10	3,263	186	56.99	7,224	160	22.28	33	2	0
2010/11	3,377	172	51.09	6,062	146	24.44	5	0.3	37.82
2011/12	3,742	175	46.79	5,616	117	21.13	80	3	35.21

PUB/MH I-11

Reference: 2012 GRA Tab 9 P. 16-19

b) Please refile and update opportunity sales and prices – peak/off-peak in Tab 9 (P.16) to include revenues achieved in each case.

ANSWER:

Please see table below.

OPPORTUNITY EXPORTS						
	On Peak GWh	**Off Peak GWh**	**On Peak Avg Price (CAD$)**	**Off Peak Avg Price (CAD$)**	**On Peak Revenues (CAD $M)**	**Off Peak Revenues (CAD $M)**
2005/06	3,142	7,161	72.73	36.75	245	265
2006/07	1,972	4,278	66.26	37.44	135	160
2007/08	2,212	4,887	66.19	32.97	162	166
2008/09	1,802	4,237	71.78	29.37	153	134
2009/10	2,497	5,100	31.14	18.74	84	100
2010/11	2,268	4,699	31.90	21.23	76	105
2011/12	1,952	4,550	28.76	22.51	59	93

PUB/MH I-11

Reference: 2012 GRA Tab 9 P. 16-19

c) Please file the tables in Tab 9 (P.19) showing unit prices for exports

ANSWER:

Please see table below.

	EXPORT REVENUES											
	2008/09			2009/10			2010/11			2011/12		
	GWh	$M (Cdn)	Avg Price	GWh	$M (Cdn)	Avg Price	GWh	$M (Cdn)	Avg Price	GWh	$M (Cdn)	Avg Price
Opportunity Bilateral	1305	101	71.37	2628	60	24.08	1851	52	28.44	1923	50	26.02
Market												
Day Ahead	4040	122	30.33	3111	59	19.09	3233	69	21.39	2720	52	18.68
Real Time	690	60	50.88	1858	71	27.33	1883	60	26.83	1859	50	23.24
Merchant	1598	86	48.08	775	26	28.29	712	27	36.93	436	17	31.10

PUB/MH I-11

Reference: 2012 GRA Tab 9 P. 16-19

a) Please refile the information in 2012 GRA Tab 9 (P.18) and provide unit price calculations for the entire period since 2000/01.

ANSWER:

Please see tables below.

	TOTAL SALES								
	DEPENDABLE SALES			OPPORTUNITY SALES			SYSTEM MERCHANT SALES		
	GWh	CAD $M	AvgPrice	GWh	CAD $M	AvgPrice	GWh	CAD $M	AvgPrice
2000/01	6,352	258	40.64	5,801	217	37.39	0	0	0
2001/02	6,277	322	51.65	6,022	281	46.63	0	0	0
2002/03	6,544	339	53.37	3,191	137	42.97	0	0	0
2003/04	6,231	295	48.46	735	52	48.46	11	0.5	44.43
2004/05	5,633	290	51.44	4,798	239	51.44	315	11	33.32
2005/06	4,044	240	59.25	10,303	510	47.73	919	63	60.07
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2007/08	3,921	209	53.22	7,099	328	44.42	1,262	72	49.17
2008/09	4,087	233	57.12	6,039	287	43.64	1,598	86	48.08
2009/10	3,263	186	56.99	7,597	184	22.98	775	26	28.29
2010/11	3,377	172	51.09	6,967	181	24.77	712	28	36.93
2011/12	3,742	175	46.79	6,502	152	22.18	436	17	31.10

	TOTAL U.S. SALES						U.S. SYSTEM MERCHANT SALES		
	U.S. DEPENDABLE SALES			U.S. OPPORTUNITY SALES					
	GWh	CAD $M	AvgPrice	GWh	CAD $M	AvgPrice	GWh	CAD $M	AvgPrice
2000/01	4,895	199	40.69	4,511	167	36.95	0	0	0
2001/02	4,767	263	55.15	5,083	247	48.66	0	0	0
2002/03	4,947	277	56.09	2,713	115	42.30	0	0	0
2003/04	5,245	259	49.45	507	35	69.42	0	0	0
2004/05	5,633	290	51.44	3,218	171	54.48	109	1	10.64
2005/06	4,044	240	59.25	8,879	401	45.12	0	0	0
2006/07	3,654	218	59.67	5,877	270	46.24	0	0	0
2007/08	3,921	209	53.22	6,618	289	44.19	0	0	0
2008/09	4,087	233	57.12	5,622	237	43.24	0	0	0
2009/10	3,263	186	56.99	7,224	160	22.28	33	2	0
2010/11	3,377	172	51.09	6,062	146	24.44	5	0.3	37.82
2011/12	3,742	175	46.79	5,616	117	21.13	80	3	35.21

PUB/MH I-11

Reference: 2012 GRA Tab 9 P. 16-19

b) Please refile and update opportunity sales and prices – peak/off-peak in Tab 9 (P.16) to include revenues achieved in each case.

ANSWER:

Please see table below.

OPPORTUNITY EXPORTS						
	On Peak GWh	**Off Peak GWh**	**On Peak Avg Price (CAD$)**	**Off Peak Avg Price (CAD$)**	**On Peak Revenues (CAD $M)**	**Off Peak Revenues (CAD $M)**
2005/06	3,142	7,161	72.73	36.75	245	265
2006/07	1,972	4,278	66.26	37.44	135	160
2007/08	2,212	4,887	66.19	32.97	162	166
2008/09	1,802	4,237	71.78	29.37	153	134
2009/10	2,497	5,100	31.14	18.74	84	100
2010/11	2,268	4,699	31.90	21.23	76	105
2011/12	1,952	4,550	28.76	22.51	59	93

PUB/MH I-11

Reference: 2012 GRA Tab 9 P. 16-19

c) **Please file the tables in Tab 9 (P.19) showing unit prices for exports**

ANSWER:

Please see table below.

	EXPORT REVENUES											
	2008/09			2009/10			2010/11			2011/12		
	GWh	$M (Cdn)	Avg Price	GWh	$M (Cdn)	Avg Price	GWh	$M (Cdn)	Avg Price	GWh	$M (Cdn)	Avg Price
Opportunity												
Bilateral	1305	101	71.37	2628	60	24.08	1851	52	28.44	1923	50	26:02
Market												
Day Ahead	4040	122	30.33	3111	59	19.09	3233	69	21.39	2720	52	18.68
Real Time	690	60	50.88	1858	71	27.33	1883	60	26.83	1859	50	23.24
Merchant	1598	86	48.08	775	26	28.29	712	27	36.93	436	17	31.10

CAC/MH I-115

Subject: **Export Prices**
Reference: **Tab 5, Pages 9 - 10**
Tab 12, Page 6 of 11, Order 150/08, #2

Preamble: **MH forecasts, contained in the current GRA, show significant decreases MH has not provided sufficient detail with respect to existing and pending export contracts to adequately understand the dynamics and workings of the contracts that result in the forecast amounts of export revenue.**

a) Please provide contract summaries for each of the existing export contracts in effect and each existing export contracts, yet to become effective.

ANSWER:

The table below provides a summary of MH's firm export contracts. Please refer to CAC/MH I-17b with respect to proposed sales. Tables 1 and 2 Tab 9 of Manitoba Hydro's Application show the total capacity and energy obligations, expressed at generation associated with these contracts.

CUSTOMER	CAPACITY (MW)	TERM
Northern States Power	500	May 2005 - April 2015
	150	November 1996 - April 2015
	200	May 1995 - April 2015
	375/325	May 2015 - April 2025
	350	May 2015 - April 2025
	125	May 2021 - April 2025
Great River Energy	150	May 1995 - April 2015
Minnesota Power	50	May 2009 - April 2015

CUSTOMER	CAPACITY (MW)	TERM
	250	June 1, 2020 - May 31, 2035
Southern Minnesota Municipal Power Agency	30	April 2008 - March 2013
Wisconsin Public Service Company	100	June 2021 - May 2027

CAC/MH I-115

Subject: **Export Prices**
Reference: **Tab 5, Pages 9 - 10**
Tab 12, Page 6 of 11, Order 150/08, #2

Preamble: **MH forecasts, contained in the current GRA, show significant decreases MH has not provided sufficient detail with respect to existing and pending export contracts to adequately understand the dynamics and workings of the contracts that result in the forecast amounts of export revenue.**

b) **In each of the five preceding years, please provide copies of the applications, including all redacted contracts, filed with regulators in the US, for contracts that MH was a party to for the sale of electricity into the US.**

ANSWER:

Manitoba Hydro did not file any applications in the U.S. with respect to contracts for the sale of electricity in the US. Manitoba Hydro is aware that counterparties have filed applications with their regulators however Manitoba Hydro was not actively involved in these proceedings, cannot speak to the content of the applications and as such declines to file them as Manitoba Hydro evidence in this proceeding .

Manitoba Hydro is aware that the requested materials are publicly available and can be accessed online. Parties interested in viewing these materials can access them using the following links:

Contract / Contracts	Regulatory / Contract Link
Northern States Power 375/325MW System Power Sale 125MW System Power Sale 350MW Diversity Sale	Minnesota Public Utilities Commission Website (www.puc.state.mn.us) (Xcel Energy Docket #10-633) https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={1000DC9E-0752-4A90-B658-1336E4E8056F}&documentTitle=20106-51457-02

Contract / Contracts	**Regulatory / Contract Link**
Minnesota Power 250MW System Power Sale	Minnesota Public Utilities Commission Website (www.puc.state.mn.us) (Minnesota Power – Docket #11-938) https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={4D2063C1-0AEA-4A21-9B83-EBEC836298D3}&documentTitle=20119-66452-02
Minnesota Power con't MP Non-Firm Energy Sale	(Minnesota Power – Docket #10-961 https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={415D0BF3-652D-47AF-B81F-42794802205D}&documentTitle=20109-54066-02
Southern Minnesota Municipal Power Agency 30MW System Participation Sale	Minnesota Public Utilities Commission Website (www.puc.state.mn.us) (Southern Minnesota Municipal Power Agency – Docket #09-536) https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={E3CD9EFD-F6E6-4BAB-BF4F-70A63E550BA2}&documentTitle=20096-39008-02

9

Forecast of Export Revenues

Ref.: IFF09-1/IFF10-2/IFF11-2

	11/12 ($M)		12/13 ($M)		13/14 ($M)		14/15 ($M)		15/16 ($M)	
		(Δ)		(Δ)		(Δ)		(Δ)		(Δ)
IFF09-1	554		583		615		590		701	
IFF10-2	461	-93	499	-84	510	-105	529	-161	611	-90
IFF11-2	363	-98	341	-158	363	-147	394	-135	469	-142
		-191		-242		-252		-196		-232

Ref.: Attachment 5 Average Price Calculations IFF11-2 2011/12 PRP

	11/12	12/13	13/14	14/15	15/16
IFF11-2 Energy Sales[1]					
Dependable Firm Contract Only	175	3263 Gwh	3156 Gwh	3156 Gwh	2115 Gwh
Estimated Opportunity Revenue	152	3960 Gwh	3970 Gwh	3799 Gwh	4745 Gwh
Total Energy Sales	327 9884 Gwh @ 3.10 ¢/Kwh	255 7253 Gwh @ 3.51 ¢/Kwh	303 7126 Gwh @ 4.25 ¢/Kwh	351 6955 Gwh @ 5.04 ¢/Kwh	424 6860 Gwh @ 6.19 ¢/Kwh

[1] Energy Sales Only. Merchant Trading Excluded

Figure 7.1

Net Export Revenues					
Gross Export Revenues minus Energy Fuel & Power Purchases					
	11/12 ($M)	**12/13 ($M)**	**13/14 ($M)**	**14/15 ($M)**	**15/16 ($M)**
Ref.: IFF11-2					
Extra Provincial	363	341	363	394	469
Fuel &Power Purchases	146	182	158	187	193
Net Export Revenue	**217**	**159**	**205**	**207**	**276**
Energy Sales minus Energy Related Fuel & Power Purchases					
Ref.: Attachment 5/CAC/MH I -3R					
Energy Sales Revenue	300	255	303	351	424
F&PP Cost	93	129	130	146	151
Net Export Revenue	**207**	**126**	**173**	**205**	**273**
Other Net Revenues in IFF 11-2	10	33	32	2	3

Figure 7.2

Summary of Exports and Imports Ref.: PUB/MH I-11/PUB/MH I-12 (a) & (b)				
	2008/09	**2009/10**	**2010/11**	**2011/12**
Total Exports PUB/MH I-111 (1)	10,107 GWh	10,860 GWh	11,343 GWh	10,244 GWh
Physical Sales PUB/MH I-12 (1)	9,818 GWh	10,218 GWh	9,866 GWh	9,884 GWh
Contract	4,840 @ 6.1	5,268 @ 4.2	4,746 @ 4.3	5,025 @ 4.0
Day Ahead & Real Time	4,978 @ 4.1	4,010 @ 3.0	5,120 @ 2.4	3,899 @ 2.1
Total Energy Purchases	672 GWh	679 GWh	637 GWh	1,244 GWh
Dependable Purchases incl. Wind	396 GWh @ 5.3	457 GWh @ 4.6	434 GWh @ 5.1	937 GWh @ 6.7
Day Ahead & Real Time	276 GWh @5.0	222 GWh @ 3.2	203 GWh @ 2.2	307 GWh @ 2.0
Average Purchase Prices	672 GWh @ 5.1	679 GWh @ 4.1	631 GWh @ 4.3	1,244 GWh @ 5.5

Figure 7.3

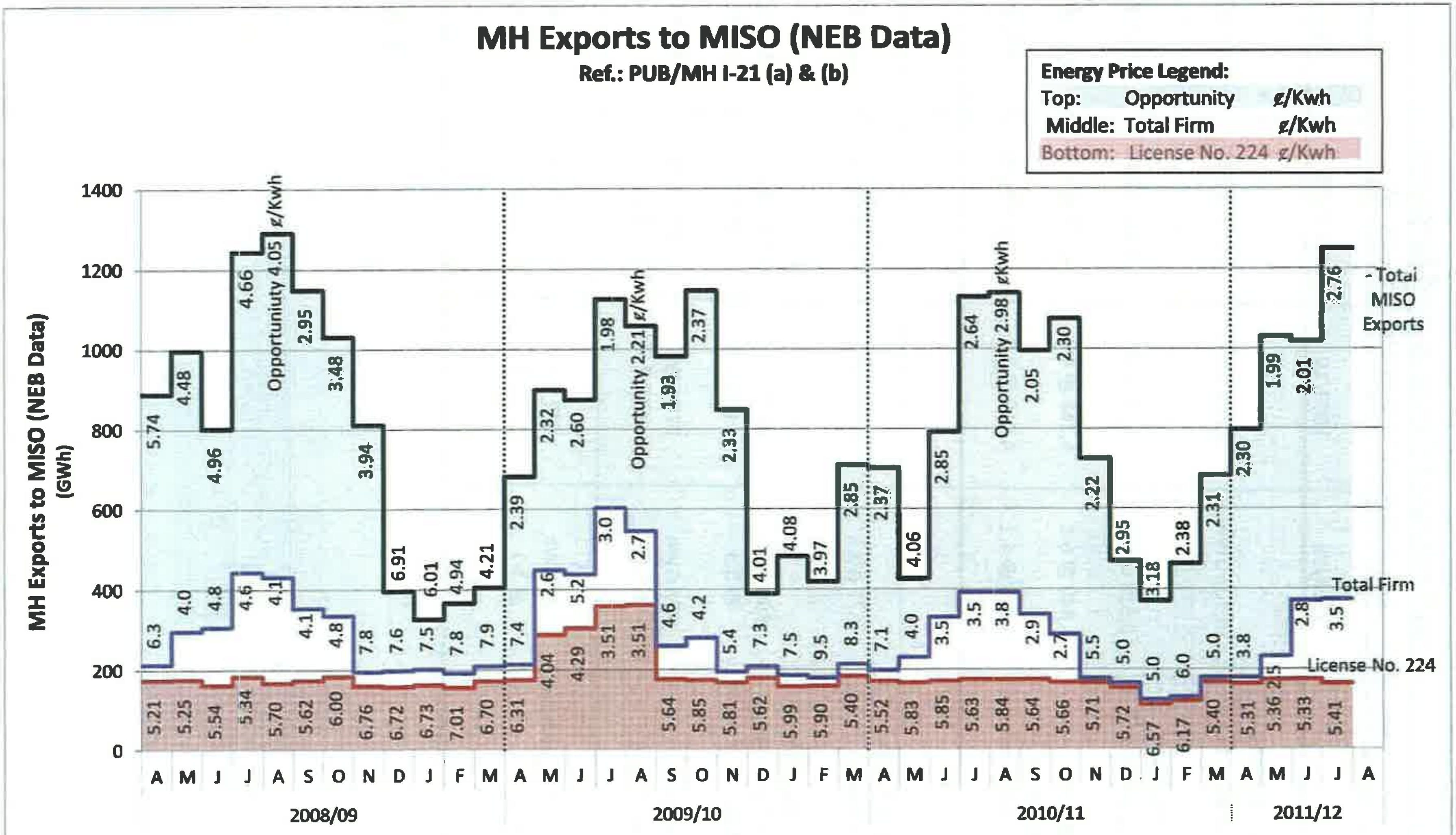

MH Exports to MISO (NEB Data)
Ref.: PUB/MH I-21 (a) & (b)
Energy Price Legend:
Top: Opportunity ¢/Kwh
Middle: Total Firm ¢/Kwh
Bottom: License No. 224 ¢/Kwh
MH Exports to MISO (NEB Data) (GWh)
- Total MISO Exports
Total Firm
License No. 224
2008/09
2009/10
2010/11
2011/12

Figure 7.4

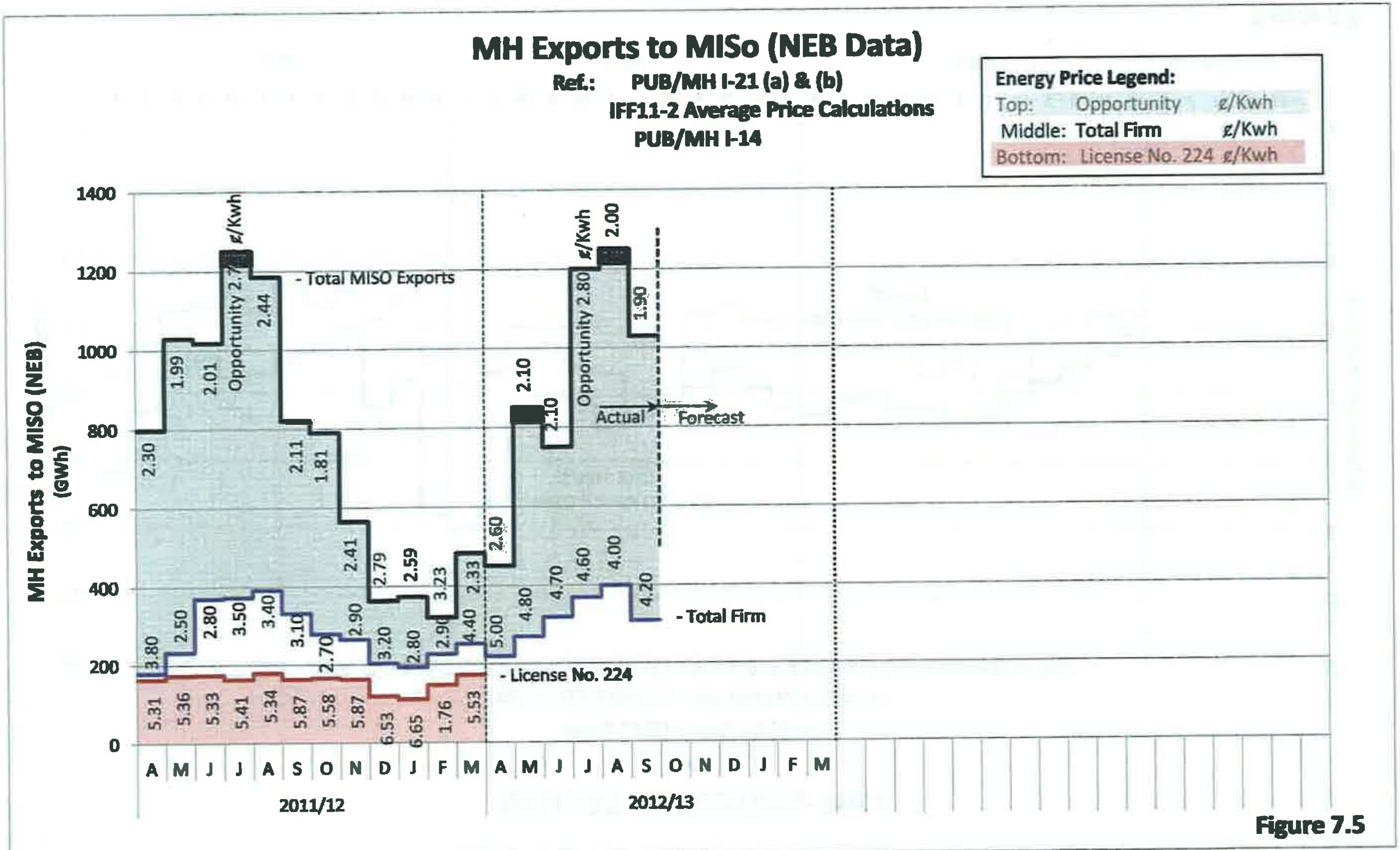

MH Exports to MISo (NEB Data)
Ref.: PUB/MH I-21 (a) & (b)
IFF11-2 Average Price Calculations
PUB/MH I-14
Energy Price Legend:
Top: Opportunity ¢/Kwh
Middle: Total Firm ¢/Kwh
Bottom: License No. 224 ¢/Kwh
MH Exports to MISO (NEB) (GWh)
- Total MISO Exports
- Total Firm
- License No. 224
Actual
Forecast
Opportunity
¢/Kwh
2011/12
2012/13

Figure 7.5

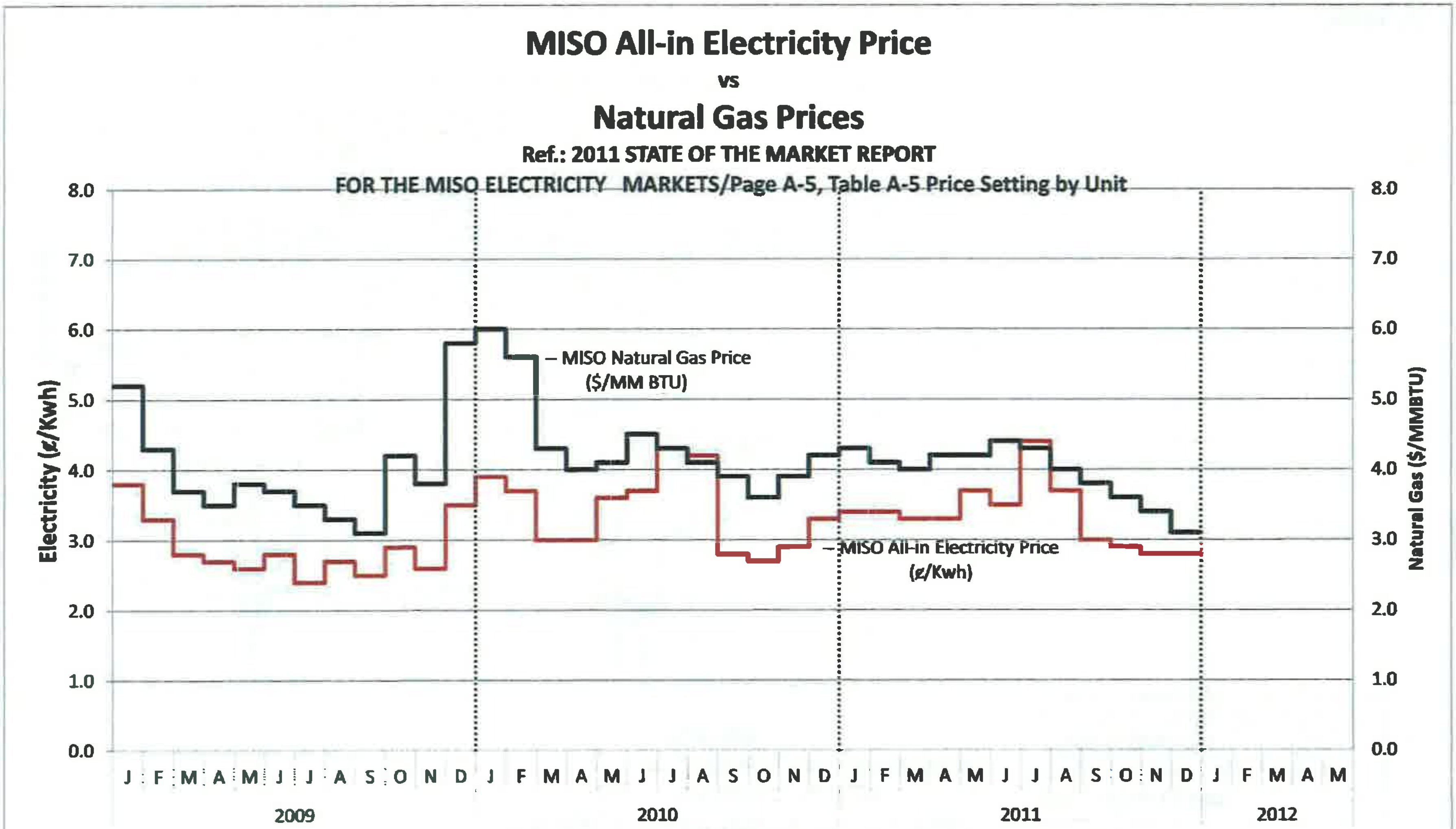

MISO All-in Electricity Price
vs
Natural Gas Prices
Ref.: 2011 STATE OF THE MARKET REPORT
FOR THE MISO ELECTRICITY MARKETS/Page A-5, Table A-5 Price Setting by Unit
Electricity (¢/Kwh)
Natural Gas ($/MMBTU)
8.0
7.0
6.0
5.0
4.0
3.0
2.0
1.0
0.0
– MISO Natural Gas Price ($/MM BTU)
– MISO All-in Electricity Price (¢/Kwh)
J F M A M J J A S O N D J F M A M J J A S O N D J F M A M J J A S O N D J F M A M
2009
2010
2011
2012

Figure 7.6

6

MISO Market Price Setting by Unit Type
Natural Gas Generation vs Market

Ref.: 2012 MISO Report Figure A-5 - page A.5 Price Setting by Unit Type

		Intervals of Natural Gas Price Setter (%)	Average (N.Gas) Generation Locational Marginal Price ($/MW)	Electricity Market Prices Minnesota Hub Ref.: Page A-24 Table A-14/A-15 D-A Peak ($/MW)	D-A Off-Peak ($/MW)
2010	J	20	52	48	38
	F	08	55	44	30
	M	06	38	35	22
	A	04	38	35	20
	M	07	35	37	23
	J	14	45	36	20
	J	22	45	42	23
	A	22	40	47	24
	S	14	37	27	13
	O	10	32	30	18
	N	10	40	30	17
	D	15	37	37	22
2011	J	20	36	38	27
	F	18	36	32	18
	M	22	30	32	19
	A	12	35	35	20
	M	20	37	32	15
	J	16	41	30	16
	J	30	40	50	30
	A	24	40	40	25
	S	08	40	33	18
	O	18	36	35	20
	N	24	32	35	17
	D	36	28	37	20

Figure 7.7

MISO Market Price Setting by Unit Type
Natural Gas Generation vs Market

Ref.: 2012 MISO Report Figure A-5 - page A.5 Price Setting by Unit Type

		Intervals of Natural Gas Price Setter (%)	Average (N.Gas) Generation Locational Marginal Price ($/MW)
2010	J	20	52
	F	08	55
	M	06	38
	A	04	38
	M	07	35
	J	14	45
	J	22	45
	A	22	40
	S	14	37
	O	10	32
	N	10	40
	D	15	37
2011	J	20	36
	F	18	36
	M	22	30
	A	12	35
	M	20	37
	J	16	41
	J	30	40
	A	24	40
	S	08	40
	O	18	36
	N	24	32
	D	36	28

Figure 7.7 (2)

MISO Energy Resource					
	MISO New SCCT (MW)	**MISO New CCCT (MW)**	**MISO Total New (MW)**	**Saskatchewan SCCT (MW)**	**Saskatchewan CCCT (MW)**
Ref. :2010 GRA Exhibit #MH-28 (actual)					
2007			386		
2008			1740		
2009			721		
Ref.: PUB/MH II-1 (c) (Actual)				Ref.: PUB/MH II-12(c)	
2010	91	Nil	91	230	Nil
2011	60	Nil	60	86	Nil
2012		1016	1016	Nil	nil
Subtotal 2007 to 2012 inclusive			**4014**		
Ref.: PUB/MH II 12 (d) (Forecast)					
2013	114	Nil	114	Nil	260
2017		650	650		
Other	80	540	540		
Total 2007 to 2017 inclusive			**5318**		

Figure 7.8

MISO Energy Supply (Twh) [1]

Ref.: PUB/MH II- 12 (a) / Ref.: PUB/MH I-18(a)

	Total		Total Imports		MH (Firm +Opportunity)	Nat.Gas (E+C)		Wind	
		(Δ)		(Δ)			(Δ)		(Δ)
2012 (6 months)	277 w.o. imports		N/A		4.4	33 [2]		19	
2011	622	-44	40.3	+12.3	9.3	32	+7	29	+5
2010	666	+71	28.0	+1.7	9.1 (3.4 +6.1)	25	+10	24	+8
2009	595	+8	26.3	-0.9	9.2 (3.3 +7.2)	15	-7	16	+12
2008	587		27.2		9.9 (4.1 +5.6)	22		4	
2008 to 2011		+35		+13.1			+10		+25

[1] Twh = Terra Watt Hours
= 1000 Gwh

[2] 2012 six month natural gas supply = 33 Twh

Figure 7.9

MH's 2011/12 IFF11-2 Assumptions

(Ref.: Attachment 3/Ref.: Attachment 5)

(2011/12 PRP)

	2012/13	2013/14	2014/15	2015/16
US Contract Sales [1] (incl. diversity)	3000	2880	2880	1925
US Market Sales	3337	3657	3490	4332
US Total (Attachment 5)	6337	6537	6378	6257
CDN Market Sales	915	589	577	603
Total Sales	7252	7126	6955	6860
Total Sales & Losses	7877	7780	7587	8484

[1] 11/12 PRP Current Expenses minus 9% losses

Current Contracts to 2015/16 - Dependable Energy		
500 MW	WSP	8000 Gwh
	MP	?
	Other	?
	Diversity	Included or not included?
	Total	3000 Gwh + Losses = 3293 Gwh

Future Contracts after 2015/16 - Dependable Energy		
• NSP	375 MW (5 x 16) Summer	?
	325 MW (5 x 12) Winter	?
	350 MW Diversity	?
• MP	250 MW (7 x 16)	?
• WPS	100 MW (7 x 16)	?

Figure 7.10

CCCT Costs vs MH's Export Revenue

Ref.: PUB/MH II-9 (b)

	Average NG Supply Cost	Efficient CCCT Variable Costs	Average MH MISO Day-Ahead Export Price	Average MH Off-Peak Opportunity Export Price	Average MH On-Peak Opportunity Export Price
	US$/MMBTU	US¢/Kwh	¢/Kwh	¢/Kwh*	¢/Kwh*
2008/09	7.84	6.6	3.4	2.9	7.2
2009/10	4.09	3.8	2.2	1.9	3.1
2010/11	4.15	3.8	2.3	2.1	3.2
2011/12	3.57	4.1	2.1	2.3	2.9

* Source: PUB/MH I-11

	PUB/MH I-16(a) ICF 15/08/11	PUB/MH I-9(a) Interpolated	Est. Average IFF11-2 US Market Price (Ref.: PUB/MH I-14/15)
2012/13	4.59	4.2	2.6
2013/14	4.71	4.7	2.7
2014/15	4.60	4.2	4.7
2015/16	5.51	4.9	6.4
2016/17	5.40	4.8	6.3
2017/18	5.23	5.1	7.1
2018/19	5.36	4.8	7.8
2019/20	5.35	4.8	9.0
2020/21	5.48	4.9	
2021/22	5.80	6.0	

Figure 7.11

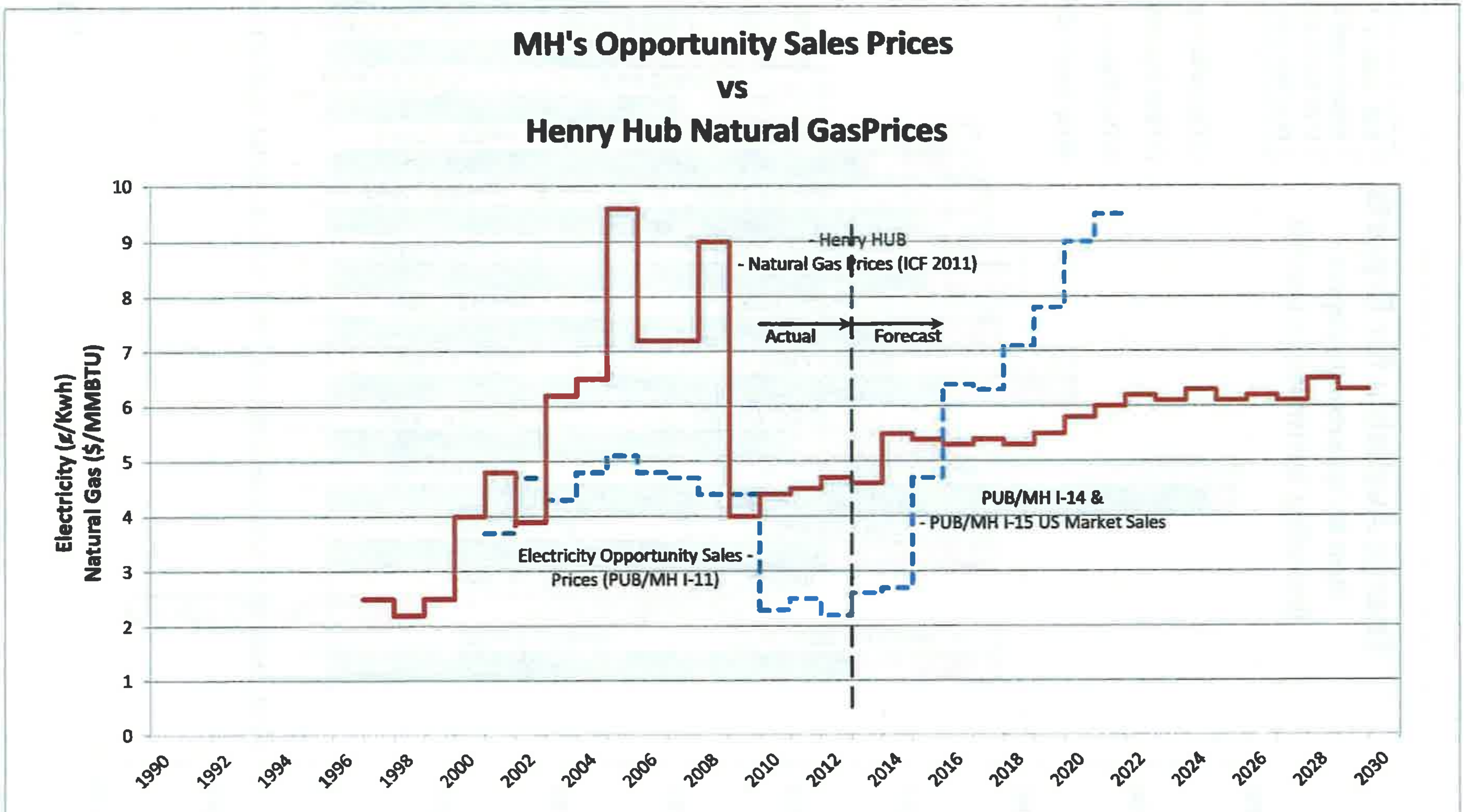

MH's Opportunity Sales Prices
vs
Henry Hub Natural GasPrices
Electricity (¢/Kwh)
Natural Gas ($/MMBTU)
0
1
2
3
4
5
6
7
8
9
10
1990
1992
1994
1996
1998
2000
2002
2004
2006
2008
2010
2012
2014
2016
2018
2020
2022
2024
2026
2028
2030
- Henry HUB
- Natural Gas Prices (ICF 2011)
Actual
Forecast
Electricity Opportunity Sales -
Prices (PUB/MH I-11)
PUB/MH I-14 &
- PUB/MH I-15 US Market Sales

Figure 7.12

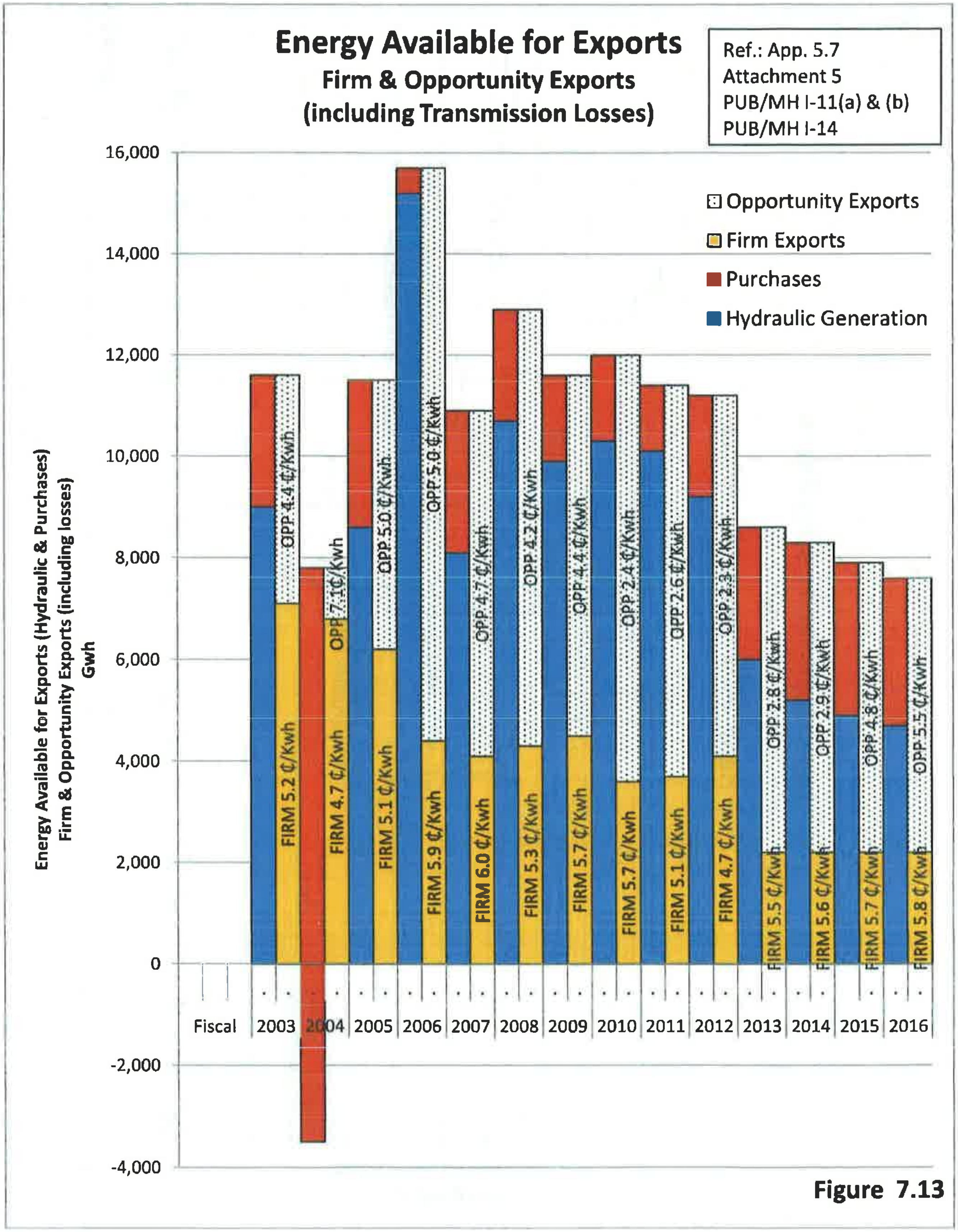

Energy Available for Exports
Firm & Opportunity Exports
(including Transmission Losses)
Ref.: App. 5.7
Attachment 5
PUB/MH I-11(a) & (b)
PUB/MH I-14
Opportunity Exports
Firm Exports
Purchases
Hydraulic Generation
Energy Available for Exports (Hydraulic & Purchases)
Firm & Opportunity Exports (including losses)
Gwh
16,000
14,000
12,000
10,000
8,000
6,000
4,000
2,000
0
-2,000
-4,000
Fiscal
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
OPP 4.4 ¢/Kwh
FIRM 5.2 ¢/Kwh
OPP 7.1¢/Kwh
FIRM 4.7 ¢/Kwh
OPP 5.0 ¢/Kwh
FIRM 5.1 ¢/Kwh
OPP 5.0 ¢/Kwh
FIRM 5.9 ¢/Kwh
OPP 4.7 ¢/Kwh
FIRM 6.0 ¢/Kwh
OPP 4.2 ¢/Kwh
FIRM 5.3 ¢/Kwh
OPP 4.4 ¢/Kwh
FIRM 5.7 ¢/Kwh
OPP 2.4 ¢/Kwh
FIRM 5.7 ¢/Kwh
OPP 2.6 ¢/Kwh
FIRM 5.1 ¢/Kwh
OPP 2.3 ¢/Kwh
FIRM 4.7 ¢/Kwh
OPP 2.8 ¢/Kwh
FIRM 5.5 ¢/Kwh
OPP 2.9 ¢/Kwh
FIRM 5.6 ¢/Kwh
OPP 4.8 ¢/Kwh
FIRM 5.7 ¢/Kwh
OPP 5.5 ¢/Kwh
FIRM 5.8 ¢/Kwh

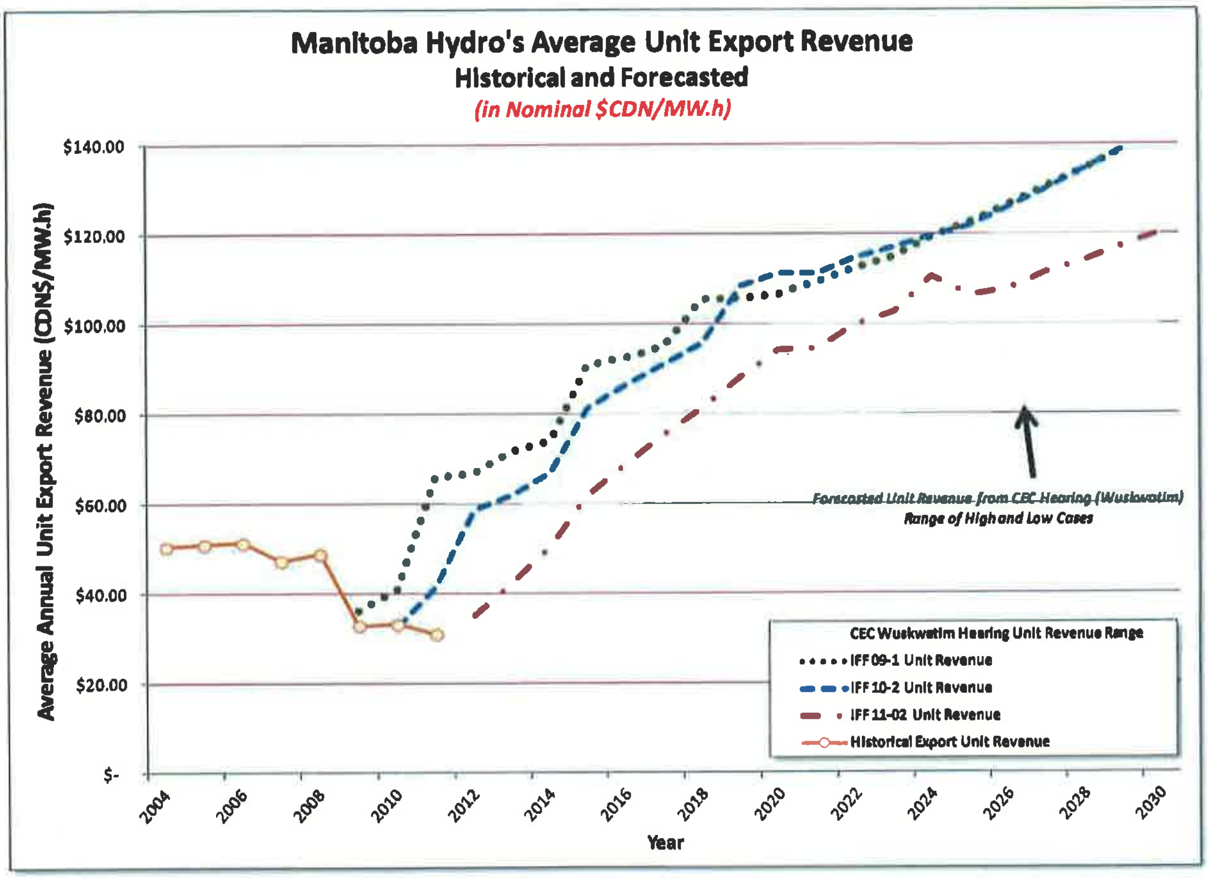
Figure 7.13

PUB/MH II-14

Reference: **PUB/MH I-19 (a) MH's Average Unit Export Revenue**

a) **Please re-file PUB/MH I-19(a) using CDN$ values consistent with the 09/10/11 IFF Revenue Assumptions;**

ANSWER:



The above chart applies actual historical exchange rates for the years 2004-2011. Post-2011 exchange rates applied are consistent with assumptions used for IFF11-2.

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MARCH 30, 2012

MANITOBA HYDRO
APPLICATION FOR INTERIM RATES EFFECTIVE APRIL 1, 2012

INDEX

Manitoba Hydro submits that under the circumstances and considering the current financial outlook, it is appropriate to grant the rate relief requested in this Application on an interim basis effective April 1, 2012 and then as soon as practical, commence a GRA process to confirm the interim rates and review a further rate increase of 3.5% on April 1, 2013. This approach will maintain the financial position of the Corporation in the short term while at the same time protect customers by allowing for a full review of the rate requests during the 2012/13 and 2013/14 GRA process.

3.1 Current Financial Position & Outlook (MH11)

2010/11 Results

The Corporation's net income from electricity operations for 2010/11 was $139 million which was a $21 million decrease from the previous fiscal year and a $10 million unfavourable variance from MH10-2.

The year over year decrease in net income of $21 million is mainly due to a decrease in net extraprovincial revenue of $30 million due to lower electricity prices from the export market resulting from the reduced power demand due to poor economic conditions, as well as the low price for competing energy sources.

The 2010/11 actual vs. MH10-2 forecast unfavourable variance of $10 million is mainly a result of lower net extraprovincial revenue ($30 million) primarily due to lower opportunity prices and volumes, which was partially offset by higher general consumers revenue and lower expenses.

Manitoba Hydro's debt to equity ratio was 73:27 at the end of March 31, 2011, which exceeds the target of 75:25. The interest coverage and capital coverage ratios were 1.27 and 1.20 respectively, which met or exceeded the target levels of 1.20. However, as demonstrated in Table 1 and 2, these ratios are projected to change dramatically over the forecast period.

A copy of the Manitoba Hydro-Electric Board Annual Report for the year-ended March 31, 2011 is provided in Appendix 3 of this Application.

2011/12 Outlook

The forecast net income from electricity operations for 2011/12 is $73 million and retained earnings are forecast at $2,400 million. The reduction in the forecast net income for 2011/12 over the previous year is primarily as a result of lower net extraprovincial revenues due to decreased prices in the export markets and lower general consumer revenue due to warmer than normal winter weather. This is partially offset by increased domestic revenues as a result of the 2.0% rate increase implemented on April 1, 2011. Total expenses are forecast to remain relatively constant in 2011/12.

Please see Appendix 4 to this Application which includes the Manitoba Hydro-Electric Board Quarterly Report for the nine months ended December 31, 2011.

2012/13 Forecast

The forecast net income from electricity operations for 2012/13 is $7 million. The reduction in the forecast net income for 2012/13 over the previous year is primarily as a result of lower extraprovincial revenues and increased operating & administrative, depreciation & amortization and finance expenses resulting from the Wuskwatim generating station coming into service. This is partially offset by increased domestic revenues as a result of forecast growth in domestic demand and the 3.5% rate increase proposed to be implemented on April 1, 2012.

Despite the addition of Wuskwatim generation and the St. Leon wind farm expansion, total export sales volumes are projected to be lower than 2011/12 due to lower water supplies. The projected increase in domestic demand is also expected to reduce total export sales volumes. Water supply conditions projected for 2011/12 were overall very favourable with above average storage carry forward from 2010/11 and total inflows among the highest on record during the first two quarters. However, precipitation across Manitoba Hydro's watersheds from September 1, 2011 to March 1, 2012 is amongst the lowest in the last thirty years resulting in a short term outlook for water supplies from snowmelt runoff below average for 2012/13. Given that the water supply outlook for 2012/13 is mainly dependent upon future precipitation conditions which are highly unpredictable, IFF11 assumes median inflows. However, with below average spring runoff expected, Manitoba Hydro cautions that there is a significant likelihood that hydraulic generation in 2012/13 will be below that forecast in IFF11. The projected deterioration in water supply conditions from 2011/12 to 2012/13, when combined with the lower projected export prices forecast in IFF11 compared to MH10-2, results in lower extraprovincial revenues. The potential impact of low water flow conditions in 2012/13 is a reduction in net revenue of approximately $400 million.

[Back to List]

Segmented Information
In Millions of Dollars (Unaudited)

Six Months Ended September 30	Electricity		Gas		Total	
	2012	2011	2012	2011	2012	2011
Revenue (net cost of gas sold)	782	800	45	46	827	846
Expenses	800	763	70	70	870	833
Net (Loss) Income	(18)	37	(25)	(24)	(43)	13
Three Months Ended September 30	Electricity		Gas		Total	
	2012	2011	2012	2011	2012	2011
Revenue (net cost of gas sold)	402	406	20	20	422	426
Expenses	406	385	35	34	441	419
Net (Loss) Income	(4)	21	(15)	(14)	(19)	7
Total Assets	13,446	12,807	579	567	14,025	13,374

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Generation and Delivery Statistics

	Six Months Ended September 30		Three Months Ended September 30	
	2012	2011	2012	2011
Electricity in gigawatt-hours				
Hydraulic generation	16,286	17,079	9,029	8,770
Thermal generation	32	43	27	24
Scheduled energy imports	128	31	4	12
Wind purchase (MB)	400	384	182	182
Total system supply	16,846	17,537	9,242	8,988
Gas in millions of cubic metres				

ELECTRIC OPERATIONS (MH11)
PROJECTED OPERATING STATEMENT
(In Millions of Dollars)

For the year ended March 31	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
REVENUES											
General Consumers											
at approved rates	1,243	1,268	1,294	1,306	1,313	1,330	1,350	1,361	1,382	1,403	1,422
additional*	0	44	92	142	194	250	309	371	438	509	584
Extraprovincial	370	359	363	394	469	502	531	554	611	821	913
Other	7	16	16	16	17	17	17	18	18	18	19
	1,620	1,686	1,765	1,859	1,992	2,099	2,208	2,304	2,448	2,751	2,938
EXPENSES											
Operating and Administrative	402	517	527	534	544	551	569	579	595	612	624
Finance Expense	399	451	460	516	551	586	658	786	830	1,178	1,145
Depreciation and Amortization	357	343	353	357	374	386	422	467	482	549	575
Water Rentals and Assessments	120	116	112	113	113	113	113	113	114	123	128
Fuel and Power Purchased	157	158	158	187	193	204	220	236	249	256	257
Capital and Other Taxes	83	85	92	99	107	116	126	132	139	128	134
Corporate Allocation	9	8	8	8	8	8	8	8	8	8	8
	1,526	1,678	1,711	1,814	1,890	1,964	2,116	2,321	2,418	2,854	2,870
Non-controlling Interest	-	(1)	(1)	(1)	(2)	(2)	(2)	(3)	(3)	(3)	(10)
Net Income	94	7	53	44	100	132	89	(21)	27	(106)	57
* Additional General Consumers Revenue											
Percent Increase	0.00%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%
Cumulative Percent Increase	0.00%	3.50%	7.12%	10.87%	14.75%	18.77%	22.93%	27.23%	31.68%	36.29%	41.06%

CONSOLIDATED INTEGRATED FINANCIAL FORECAST (IFF11-2)

ELECTRIC OPERATIONS (MH11-2)
PROJECTED OPERATING STATEMENT
(In Millions of Dollars)

For the year ended March 31	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
REVENUES											
General Consumers											
at approved rates	1 186	1 290	1 294	1 306	1 313	1 330	1 350	1 361	1 382	1 403	1 422
additional*	0	45	106	156	208	265	325	387	455	527	603
Extraprovincial	363	341	363	394	469	502	531	554	611	821	913
Other	7	16	16	16	17	17	17	18	18	18	19
	1 556	1 693	1 778	1 873	2 007	2 114	2 224	2 320	2 466	2 769	2 957
EXPENSES											
Operating and Administrative	398	447	532	542	548	554	571	580	595	611	622
Finance Expense	385	440	452	504	537	570	640	763	803	1 147	1 109
Depreciation and Amortization	353	401	354	358	375	387	422	468	483	550	576
Water Rentals and Assessments	119	106	112	113	113	113	113	113	114	123	128
Fuel and Power Purchased	146	182	158	187	193	204	220	236	249	256	257
Capital and Other Taxes	82	87	92	99	107	116	126	132	139	128	134
Corporate Allocation	9	9	8	8	8	8	8	8	8	8	8
	1 492	1 672	1 709	1 810	1 881	1 952	2 100	2 300	2 393	2 823	2 833
Non-controlling Interest	-	(1)	(1)	(1)	(2)	(2)	(2)	(3)	(3)	(3)	(10)
Net Income	64	20	68	62	124	159	121	18	70	(57)	113
* Additional General Consumers Revenue											
Percent Increase	0.00%	3.57%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%
Cumulative Percent Increase	0.00%	4.50%	8.16%	11.94%	15.86%	19.92%	24.11%	28.46%	32.95%	37.61%	42.42%

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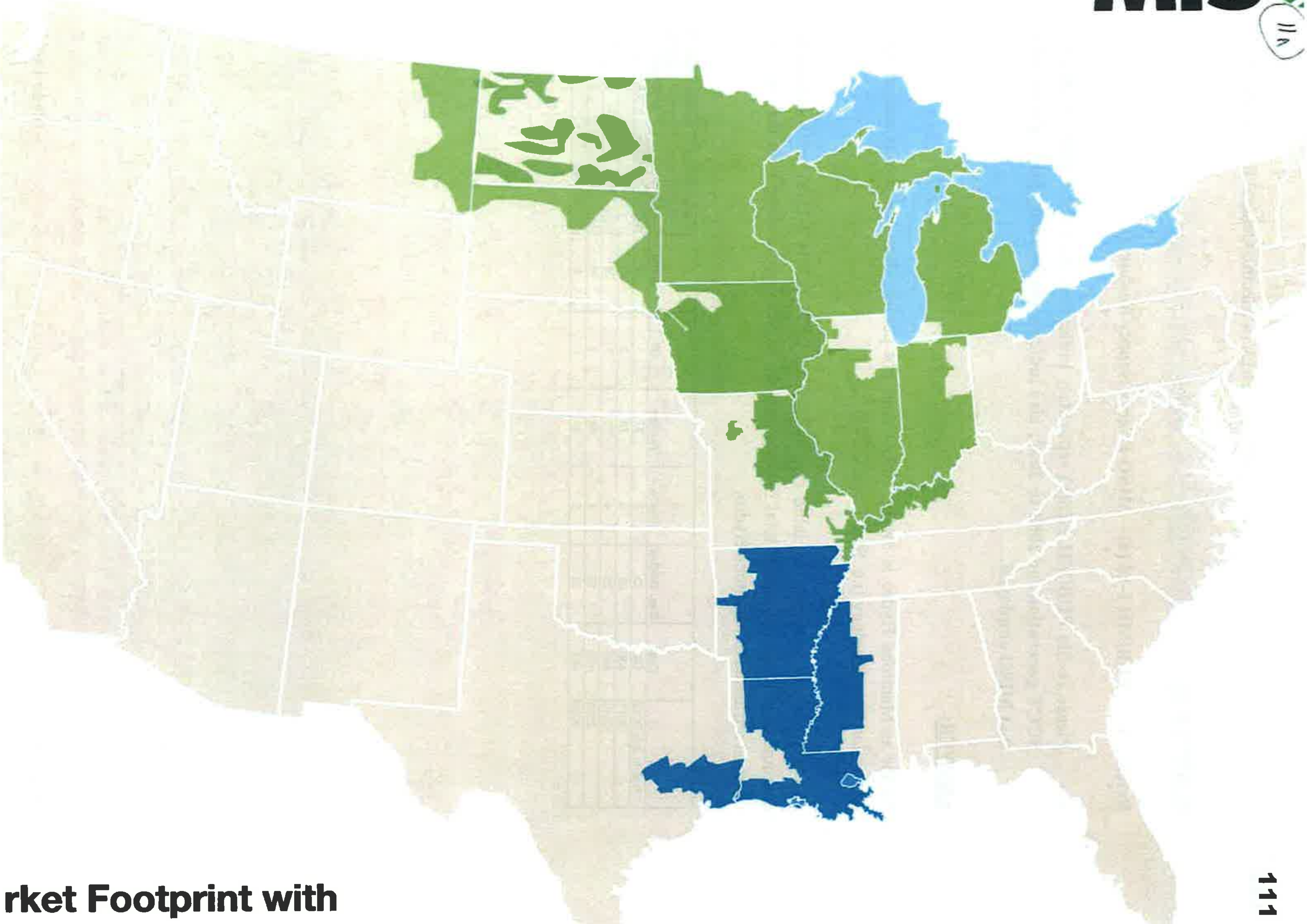

rket Footprint with
ergy Electric Territory

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PUB/MH II-12

Reference: PUB/MH I-18 (a) – MISO Energy Supply Resources

a) **Please re-file PUB/MH I-18(a) separately indicating the CCCT generation and SCCT generation for 2008 to 2012; also indicate the imports (MH's plus other) that MISO employed.**

ANSWER:

As far as Manitoba Hydro is aware, MISO does not publish data that details natural gas generation by technology (i.e. SCCT or CCCT).

The chart below provides the table originally filed in PUB/MH I-18(a) with additional columns to indicate the annual total imports into the MISO region, along with the share of the total attributed to Manitoba Hydro.

	Coal	Gas, Oil/Gas	Hydro	Nuclear	Oil	Wind	Imports into MISO Region (Total)	Manitoba Hydro Physical Exports to the US
*Year to July 2012	182	33	3	37	3	19	[redacted]	4.4
2011	436	32	5	78	2	29	40.3	9.3
2010	490	25	4	93	2	24	28.0	9.1
2009	453	15	2	82	1	16	26.3	9.2
2008	463	22	2	69	0	4	27.2	9.9

PUB/MH II-12

Reference: PUB/MH I-18 (a) – MISO Energy Supply Resources

b) Include in the refilled table a line item for MH's contribution.

ANSWER:

Please see Manitoba Hydro's response to PUB/MH II-12(a).

PUB/MH II-12

Reference: PUB/MH I-18 (a) – MISO Energy Supply Resources

c) Please provide an update of 2010 GRA Exhibit #MH-28 separately indicating the 2007 to date new CCCT and new peaking natural gas generation that have been added into the MISO Market.

ANSWER:

Manitoba Hydro does not have available a more detailed analysis of the chart that was included in 2010 GRA Exhibit #MH-28 which provides the gas technology type (combustion turbine vs combined cycle).

Manitoba Hydro can provide the following list of natural gas plants commissioned in the 2010-2012 period in the MISO region. This list is based on publically available data sources and may not be complete:

Commissioned Natural Gas Facilities in MISO - 2010-2012

Year	Facility	Capacity (MW)	Technology Type
2010	Culbertson Peaking	91	SCCT
2011	Marsh Utilities M1	60	SCCT
2012	Fremont Energy Center	716	CCCT
2012	Deer Creek Station	300	CCCT
	Total	1,168	

PUB/MH II-12

Reference: PUB/MH I-18 (a) – MISO Energy Supply Resources

d) Please provide an updated forecast of new CCCT and new peaking natural gas generation that is or may be coming online in MISO by 2016.

ANSWER:

As noted in response to PUB/MH II-12(c), Manitoba Hydro does not have complete information on potential future plant additions in the MISO region.

Below is a list of planned/proposed natural gas generation facilities for the MISO region, compiled from public information sources that may or may not be complete. The facilities with Not Yet Defined in the 'Year' column indicate these are proposed facilities that have not yet been provided a defined commissioning date.

Planned/Proposed Natural Gas Facilities in MISO

Year	Facility	Capacity (MW)	Technology Type
2013	Pioneer Generating Station	45	SCCT
2013	Lonesome Creek Station	45	SCCT
2013	Fairmont Energy Station	24	SCCT
2017	Marshalltown Generating Station	650	CCCT
Not yet defined	Morton CT Plant (Heskett)	80	SCCT
Not yet defined	Mesaba Gas Plant	540	CCCT

PUB/MH II-12

Reference: PUB/MH I-18 (a) – MISO Energy Supply Resources

e) **Please provide a 2007 to 2016 listing of new CCCT and new peaking generation that has or may come online in Saskatchewan by 2016.**

ANSWER:

The following information was compiled from publicly available sources, and may or may not include all future /planned stations.

Saskatchewan Natural Gas Plants 2007-2016

Name	Commissioning Date	Capacity (MW)	Type
North Battleford Energy Centre	2013	260	Natural gas - CCCT
Spy Hill Power Plant	2011	86	Natural gas -SCCT
Ermine Power Station	2010	92	Natural gas - SCCT
Yellowhead Power Station	2010	138	Natural gas - SCCT

References:

North Battleford Energy Centre – http://www.marketwire.com/press-release/North-Battleford-Energy-Centre-Project-Breaks-Ground-at-Official-Ceremonies-TSX-NPI.UN-1275693.htm

Spy Hill Power Plant –
http://www.northlandpower.ca/WhatWeDo/PrerevenueProjects/Project.aspx?projectID=27#m=2

Ermine & Yellowhead Power Stations –
http://www.saskpower.com/about_us/generation_transmission_distribution/natural_gas_stations.shtml

2011 State of the Market Report for the MISO Electricity Markets

Prepared by:

POTOMAC ECONOMICS

Independent Market Monitor for MISO

June 2012

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I. Prices and Revenues

MISO has operated competitive wholesale electricity markets for energy and FTRs since April 2005. The market added regulating and contingency reserve products (jointly known as ancillary services) in January 2009, and a voluntary capacity auction began in June 2009. In this section, we summarize prices and revenues associated with the day-ahead and real-time energy markets.

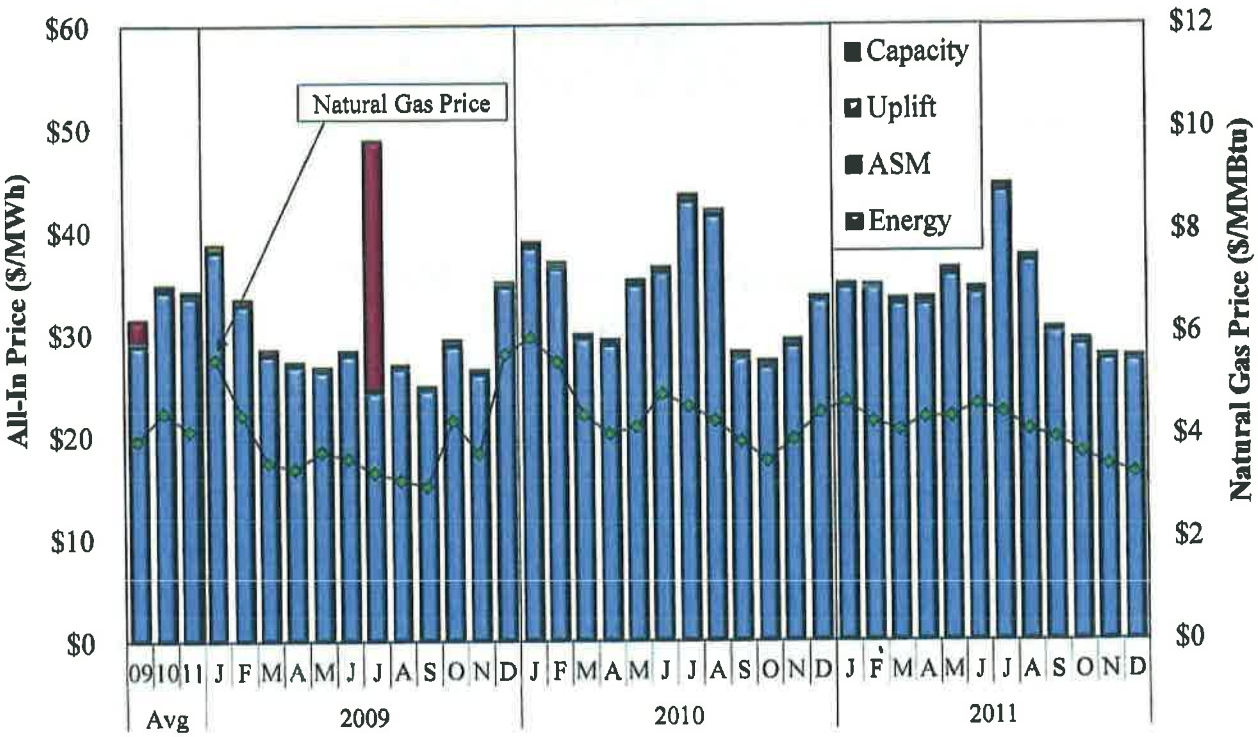
A. Prices

In a well-functioning, competitive market suppliers have an incentive to offer at their marginal costs. Therefore, energy prices should be positively correlated with the marginal costs of generation. For most suppliers, fuel comprises the majority of these costs. In MISO, coal-fired resources are marginal most often, but natural gas-fired resources tend to set prices at higher load levels and so have an outsized impact on average energy prices.

Figure A1: All-In Price of Electricity

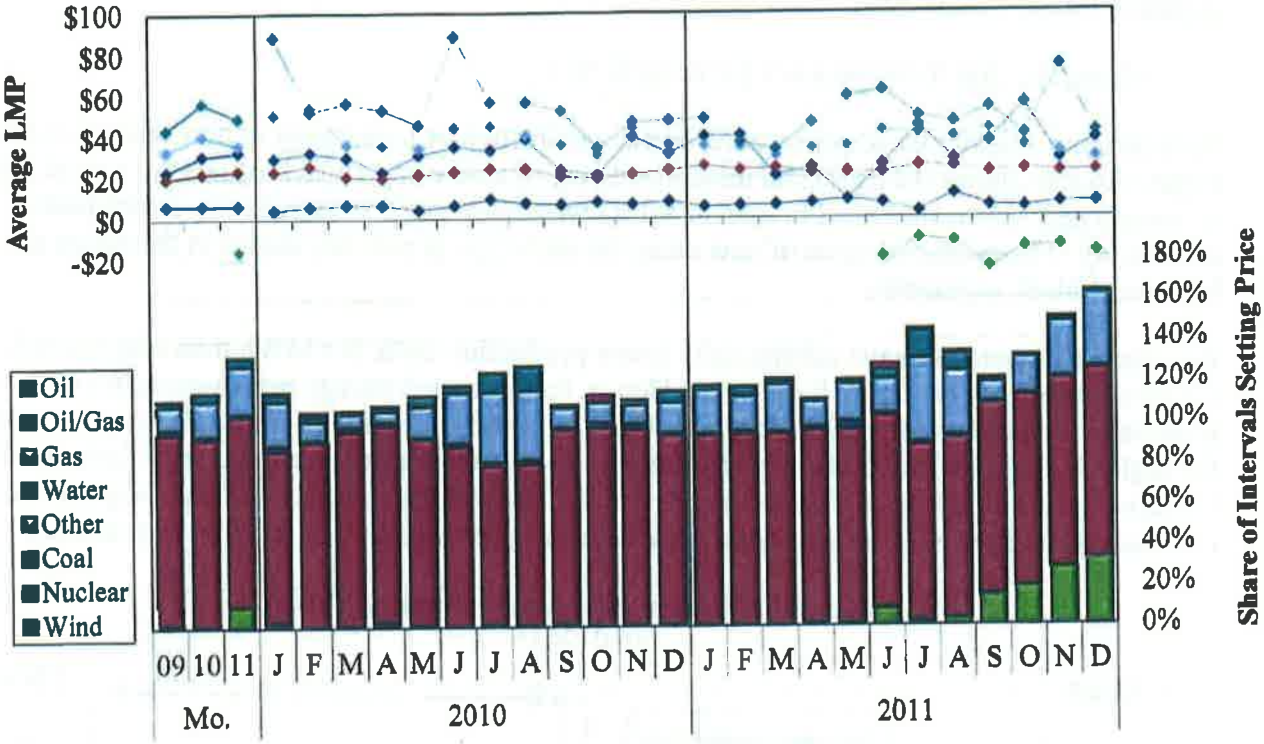
Figure A1 shows the "all-in" price of electricity from 2009 to 2011 and the price of natural gas.[1] The all-in price represents the cost of serving load in MISO's real-time market. It includes the load-weighted real-time energy price, as well as real-time ancillary service costs, uplift costs, and capacity costs (VCA price times capacity requirement) per MWh of real-time load.

Figure A1: All-In Price of Electricity
2011: Peak Hours



1 Specifically, the Chicago City Gate spot price for natural gas, as published by Platts.

Figure A5: Price-Setting by Unit Type
2010–2011



<u>Key Observations: Prices</u>

i. Real-time energy prices in MISO averaged $33.61 per MWh, and ranged from $29 in the West region to $37 in the East. Energy prices were 1.9 percent lower than in 2010 due to:

a) lower natural gas prices, which declined 8 percent, and

b) lower average load, which declined 0.6 percent, as well as the lower summer loads in August when the weather was mild.[3]

ii. The average all-in price fell 2 percent for the same reasons that caused energy prices to fall as energy prices continued to constitute 99 percent of the all-in price.

- The total contribution to the all-in price from uplift costs, including RSG payments and PVMWP, decreased 8 cents to $0.31 per MWh and remained less than 1 percent of the all-in price.

- The contribution to the all-in price in 2011 by ancillary services costs was 15 cents, and capacity costs contributed less than one cent per MWh. These levels are virtually unchanged from 2010. Very low capacity prices are expected under the current market design when there is a prevailing capacity surplus in MISO.

3 This value is adjusted for membership changes, including the departure of FirstEnergy in June.

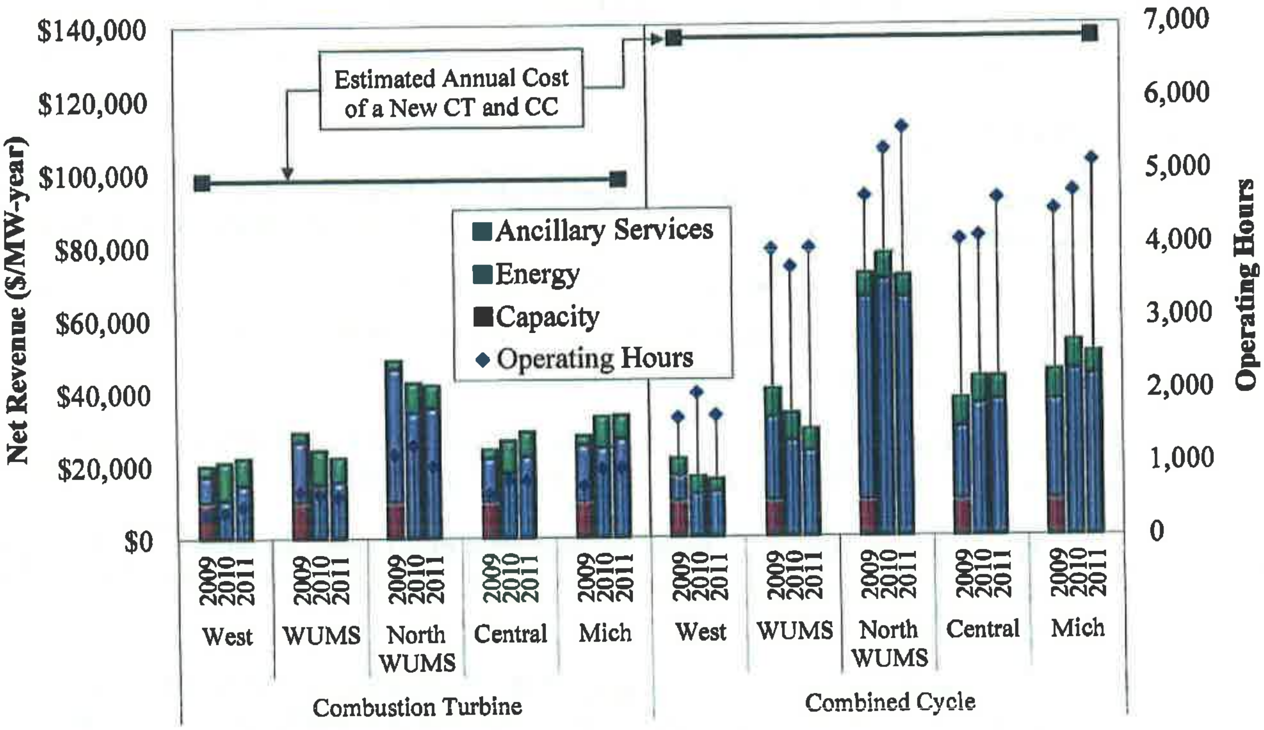
Commission) to account for variable Operations and Maintenance (O&M) costs, fuel costs, and expected forced outage rates.

Figure A6: Net Revenue and Operating Hours

To determine whether these net revenue levels would support investment in new resources, the Figure A6 also shows the estimated annualized cost of a new unit (which equals the annual net revenue a new unit would need to earn in MISO wholesale markets to make the investment economic). The estimated costs of new entry for each type of unit are shown in the figure as horizontal black segments).

Because CC generators have substantially lower production costs per MWh than simple-cycle CT generators, they run more frequently. Hence, the estimated energy net revenues for CC generators are substantially higher than for CTs. Currently capacity prices are the same across the regions, although MISO has filed to establish locational requirements that will likely result in locational price differences. Since CTs provide far less energy, capacity and ancillary service revenues typically have a larger impact on a CT's net revenues than on a CC's net revenues.

Figure A6: Net Revenue and Operating Hours
2010–2011



<u>Key Observations: Net Revenues</u>

i. The net revenue in 2011 for both types of units was substantially less than CONE in all regions. This is consistent with expectations because the MISO region continues to exhibit a capacity surplus and did not experience significant shortages in 2011.

Figure A10: Availability of Capacity, During Peak Load Hour
2011

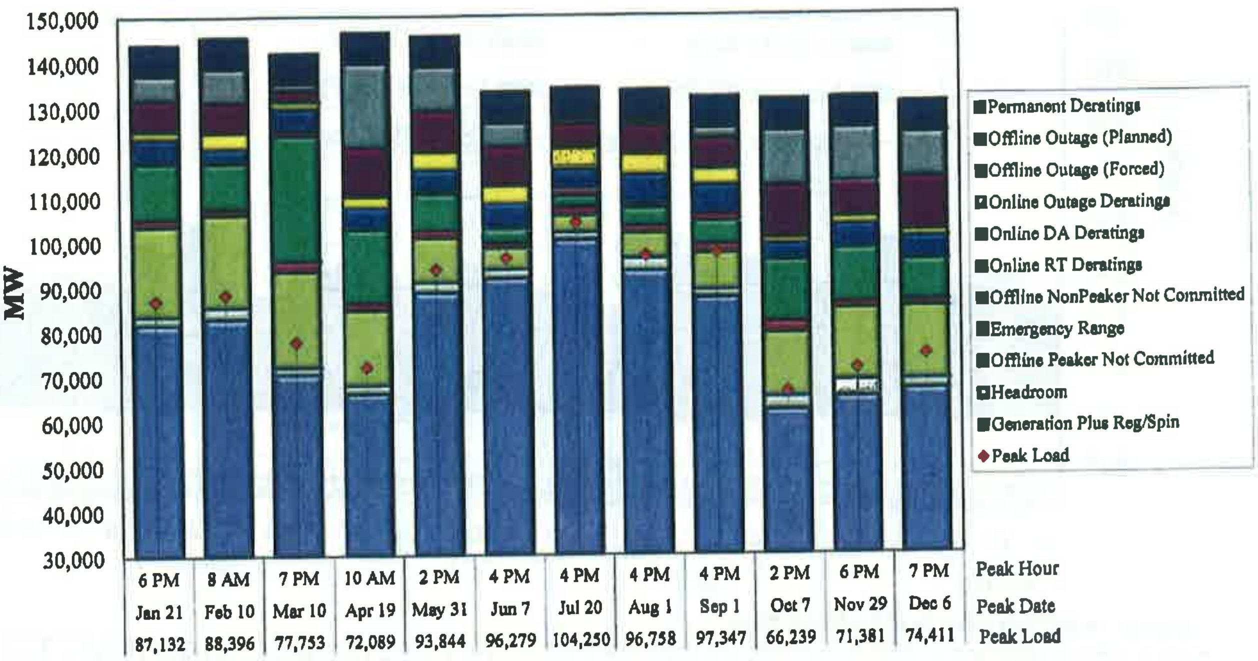
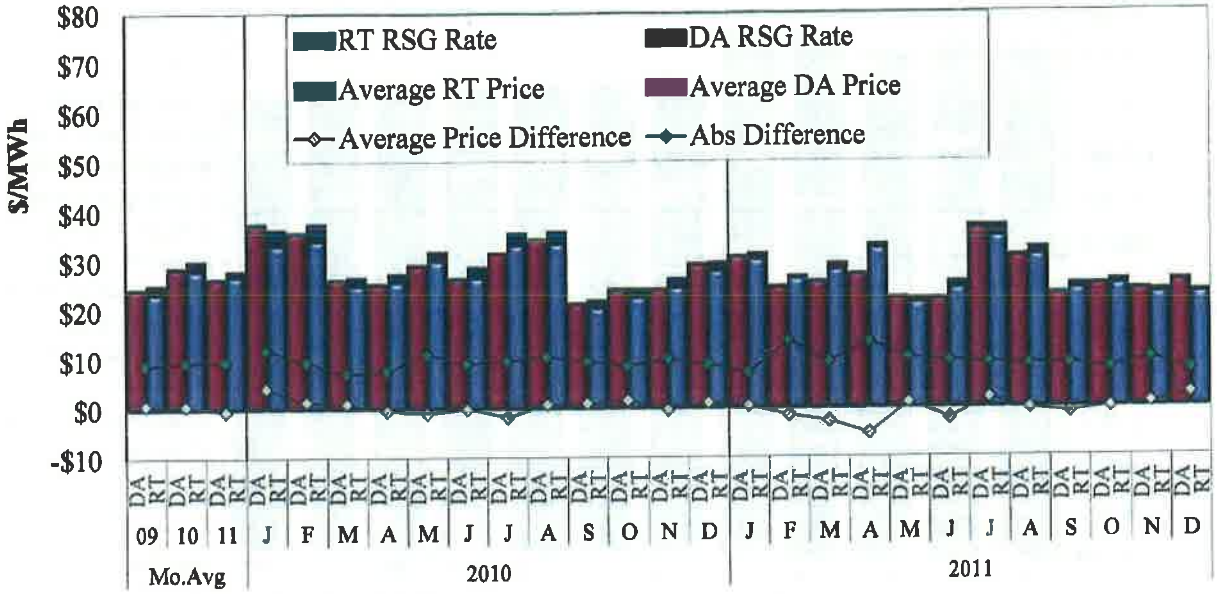


Figure A11: Capacity Unavailable During Peak Load Hours

Figure A11 is very similar to the prior figure except that it shows only the offline or otherwise unavailable capacity during the peak hour of each month. Maintenance planning should maximize resource availability in summer peak periods, when the demands of the system (and prices) are highest. As a consequence, the larger subset of units in service should increase the total non-outage deratings during these periods.

The figure also shows the quantity of permanent deratings (relative to nameplate capacity), which, due to operating limitations, is unavailable in any hour. Many units cannot produce their nameplate output under normal operation, particularly older baseload units in the region. Wind resources additionally often have ratings in excess of available transmission capability.

Figure A19: Day-Ahead and Real Time Price
2009–2011: Minnesota Hub



Average DA-RT Difference (% of Real-Time Price)

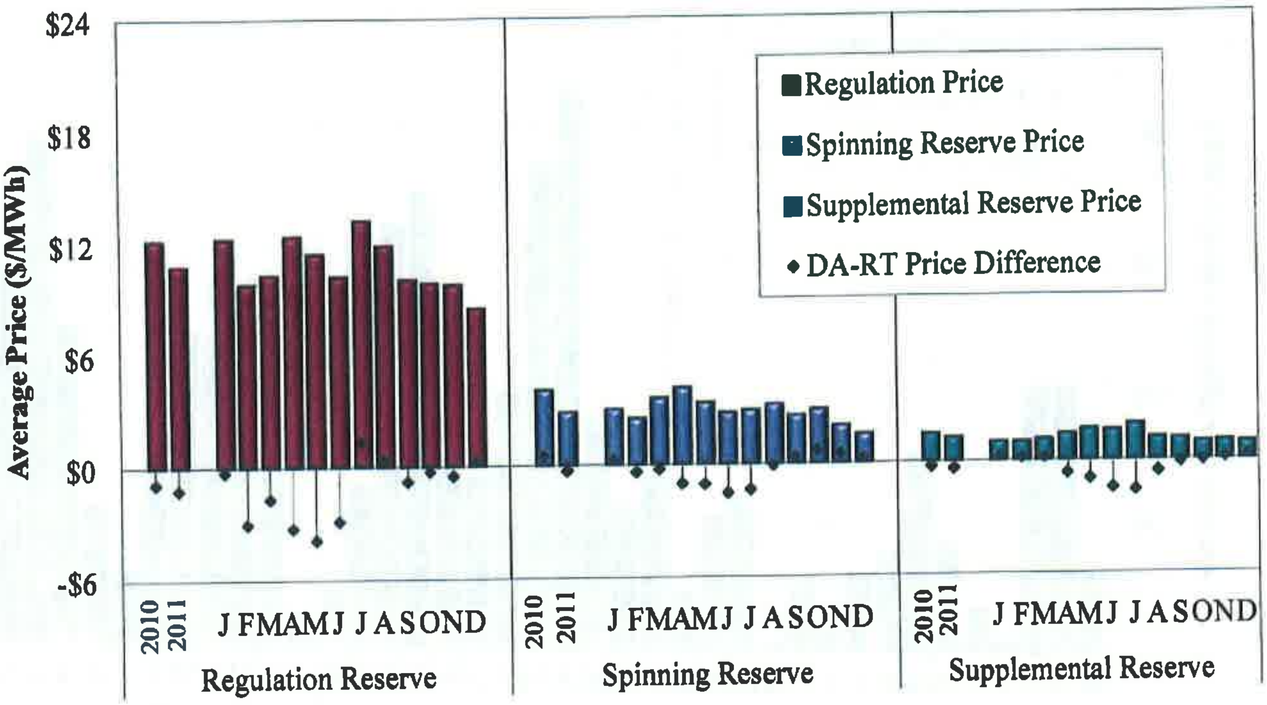
Excluding RSG	4	2	-2	13	4	4	-2	-3	0	-5	3	5	7	-1	4	1	-6	-10	-16	5	-9	6	-1	-4	0	4	11
Including RSG	-3	-5	-5	4	-5	-2	-8	-8	-8	-13	-5	-2	0	-8	-1	-2	-8	-13	-18	1	-13	0	-5	-8	-3	1	10

MISO's ancillary service markets consist of day-ahead and real-time markets for regulating reserves, operating reserves, and supplemental reserves that are jointly optimized with the energy markets. These markets have operated without significant issue since their introduction in January 2009.

Figure A20: Day-Ahead Ancillary Services Prices and Price Convergence

Figure A20 shows monthly average day-ahead clearing prices in 2011 for each ancillary service products, along with day-ahead to real-time price differences.

Figure A20: Day-Ahead Ancillary Services Prices and Price Convergence
2011



Key Observations: Day-Ahead and Real-Time Price Convergence

i. In 2011, there was a MISO-wide day-ahead premium of 1.8 percent, which is expected given the real-time RSG allocated to net real-time purchases and the lower volatility of prices in the day-ahead market.

- After accounting for the RSG cost allocations to load purchases, the MISO-wide premium fell to -0.7 percent.
- The unadjusted premium of 1.8 percent is down from approximately 3 percent in 2010. The smaller day-ahead premium in 2011 is in line with lower real-time RSG cost allocations, which averaged $0.96 per MWh in 2011 compared with $2.04 per MWh in 2010.
- Over the long term, we expect small day-ahead premiums because scheduling load day-ahead limits the risk associated with higher real-time price volatility.

ii. Modest premiums prevailed in all of the MISO regions, except at Minnesota Hub in the West region. West region prices early in the year were affected by less real-time congestion than expected day-ahead due to increasing real-time wind output and outages.

Figure A50: Manual Wind Curtailments
2009–2011

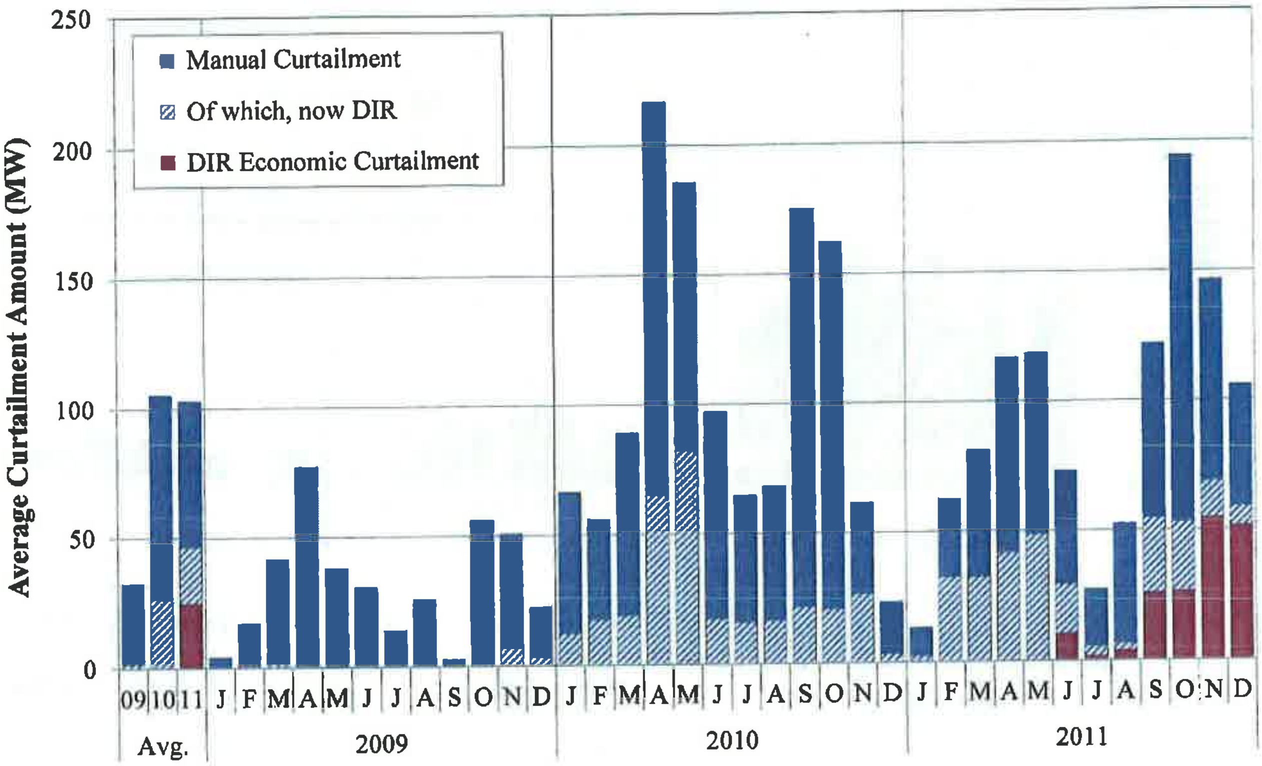


Figure A51: Wind Volatility

Because wind output is dependent on the changing velocity of the wind resource, wind output can be highly volatile. As a result, volatility in wind output must be managed through redispatch of other resources, curtailment of wind resources, or the commitment of peaking resources. Figure A51 summarizes the volatility of wind output on a monthly basis over the past two years by showing:

- The average absolute value of the sixty-minute change in wind generation in the blue line;
- The largest 5 percent of hourly decreases in wind output in the blue bars;
- The maximum hourly decrease in each month in the drop lines.

Figure A81: Average Hourly Day-Ahead Net Imports
2011, by Interface

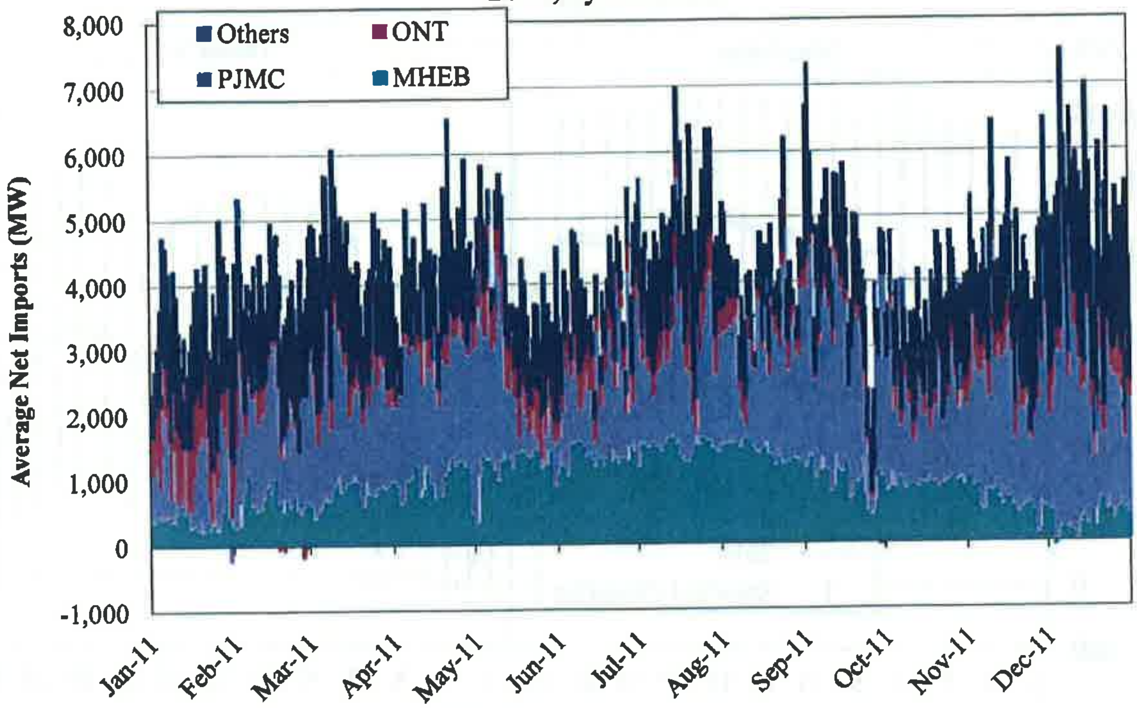


Figure A82: Average Hourly Real-Time Net Imports
2011, by Interface

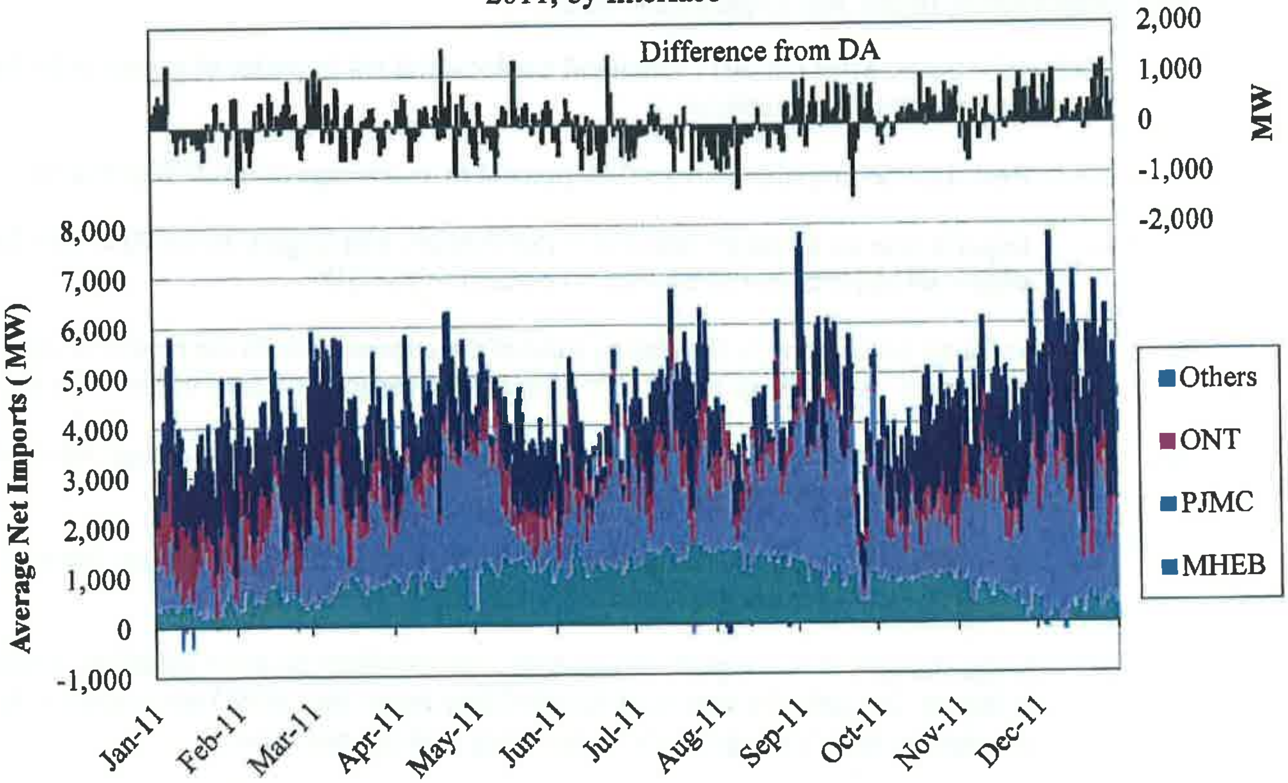


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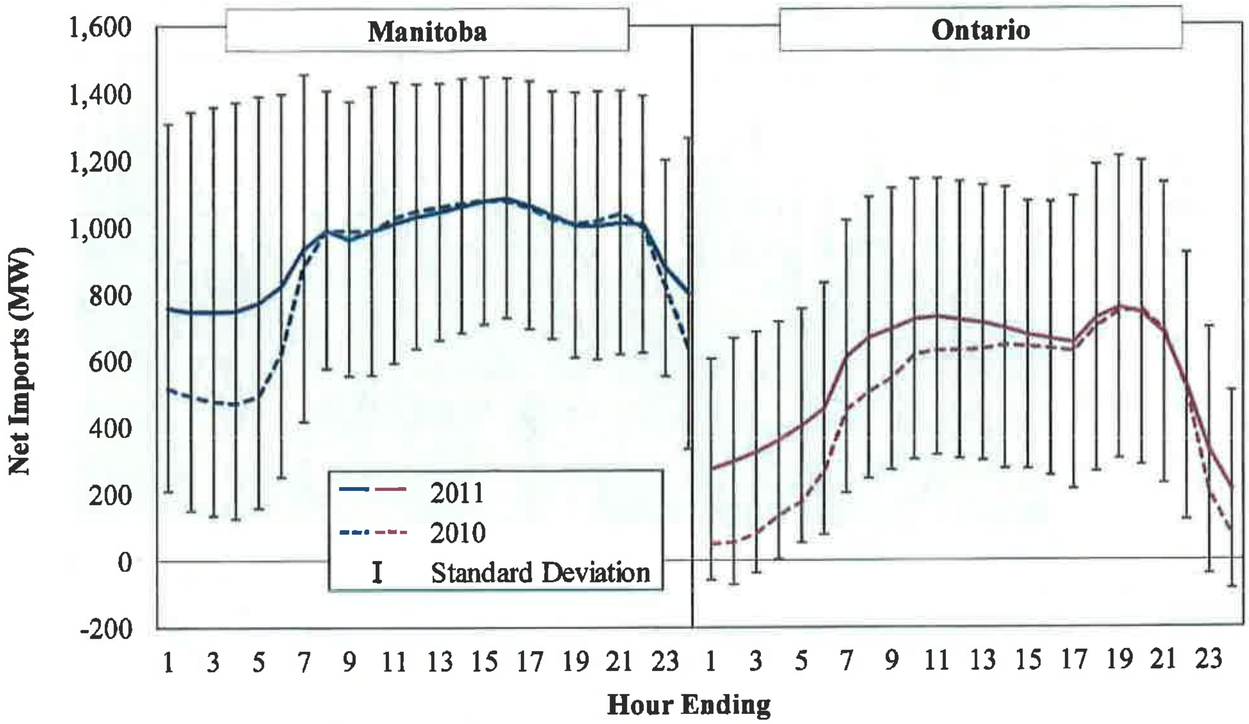
Figure A84: Average Hourly Real-Time Net Imports, Canada
2011



Key Observations: Import and Export Quantities

i. As in prior years, MISO in 2011 remained a substantial net importer of power in both the day-ahead and real-time markets.

- Real-time net imports increased 49 percent to an average of 4.6 GW per hour.
- Imports rose on all major interfaces; the increase was largest on the PJM interface, where net imports increased over 50 percent to 1.6 GW.

ii. The consistent net imports in the energy market are consistent with the results of the capacity market. An average of 3.4 GW of imported capacity cleared in the VCA in 2011.

iii. Real-time imports averaged 77 MW greater than day-ahead imports, although this varied considerably by hour and season.

- Net imports were overscheduled day-ahead in summer (by 192 MW per hour on average), but underscheduled in all other months (169 MW).
- Large changes in net imports in real-time can contribute to price volatility. Declines in imports in particular can result in reliability issues that MISO must manage by committing additional generation, including peaking resources.

PUB/MH I-16

Reference: 2012/13 and 2013/14 GRA/Tab 4/ Attachment 5 (July 20/12)

a) Natural Gas Supply Prices Assumptions and ICF – 2011 Projections

Please provide the ICF comparison of their natural gas supply price forecasts provided during the 2010 GRA hearing and also provide the prices submitted by CENTRA (Augu.15/11) to PUB.

ANSWER:

Please see the attachments to this response.

11 a

Exhibit # MH-60
Transcript Page #2721

Manitoba Hydro Undertaking #56

Extend ICF's natural gas forecast approximately 10 - 15 years.

ICF Response:

ICF Forecast of Henry Hub Natural Gas Prices: 2011 -2035

Year	Nominal $/MMBtu	2010$/MMBtu
2011	4.2	4.1
2012	4.7	4.5
2013	5.0	4.6
2014	5.7	5.2
2015	5.3	4.6
2016	6.4	5.6
2017	7.0	5.9
2018	7.1	5.8
2019	7.7	6.2
2020	8.4	6.6
2021	8.8	6.7
2022	8.7	6.5
2023	8.8	6.4
2024	9.2	6.5
2025	9.4	6.5
2026	9.8	6.6
2027	10.0	6.6
2028	10.2	6.5
2029	10.4	6.5
2030	10.7	6.5
2031	11.3	6.7
2032	11.9	6.9
2033	11.8	6.7
2034	12.5	6.9
2035	12.9	6.9

Note: 2.5% annual inflation is assumed.

Centra Gas Manitoba Inc.
Process for Review of Gas Supply, Storage and Transportation Arrangements

PUB/Centra 21
Attachment
August 15, 2011

		ICF Base Case Price Forecast at Henry Hub (Real $/MMBtu)			ICF Base Case Price Forecast at AECO (Real $/MMBtu)	
1		**November 2008**	**April 2011**		**November 2008**	**April 2011**
2	2001	4.79		2001	4.23	
3	2002	3.92		2002	3.01	
4	2003	6.24		2003	5.35	
5	2004	6.53		2004	5.49	
6	2005	9.56		2005	7.78	
7	2006	7.17		2006	6.05	
8	2007	7.20		2007	6.19	
9	2008	9.02	9.02	2008	7.81	7.89
10	2009	5.40	3.98	2009	4.18	3.56
11	2010	7.31	4.38	2010	6.73	3.89
12	2011	6.84	4.59	2011	6.18	3.86
13	2012	7.30	4.71	2012	6.69	3.87
14	2013	7.04	4.60	2013	6.47	3.79
15	2014	7.73	5.51	2014	7.16	4.65
16	2015	7.61	5.40	2015	6.99	4.64
17	2016	7.46	5.23	2016	6.53	4.49
18	2017	7.66	5.36	2017	6.82	4.64
19	2018	7.85	5.35	2018	7.04	4.60
20	2019	7.93	5.48	2019	7.17	4.74
21	2020	8.22	5.80	2020	7.41	5.06
22	2021	7.34	5.99	2021	5.93	5.28
23	2022	8.16	6.20	2022	7.00	5.51
24	2023	8.14	6.11	2023	6.93	5.46
25	2024	7.98	6.34	2024	6.49	5.71
26	2025	8.20	6.14	2025	6.87	5.52
27	2026	8.66	6.22	2026	7.39	5.65
28	2027	8.68	6.14	2027	7.43	5.56
29	2028	9.12	6.52	2028	7.96	5.95
30	2029	9.00	6.27	2029	7.82	5.70
31	2030	9.49	6.61	2030	8.35	6.08

ICF Forecasts of U.S. CO_2 Emissions Allowance Prices (2010 $/ton)

Year	Previous	Current
2011	0	0
2012	0	0
2013	0	0
2014	0	0
2015	22	0
2016	24	0
2017	25	0
2018	26	10 - 15

- ICF has also lowered its forecasts of likely CO_2 emission allowance prices due to political developments. This lowers interest in hydro supply all else equal. However, much environmental regulatory uncertainty remains, creating continued interest in low CO_2 options. For example, US EPA regulations on greenhouse gas emissions are still moving forward and regional initiatives are continuing. Also, concern about CO_2 still blocks new coal power plant options; none broke ground in the U.S. during 2009 - 2010. This eliminates an option that has low volatility in costs.

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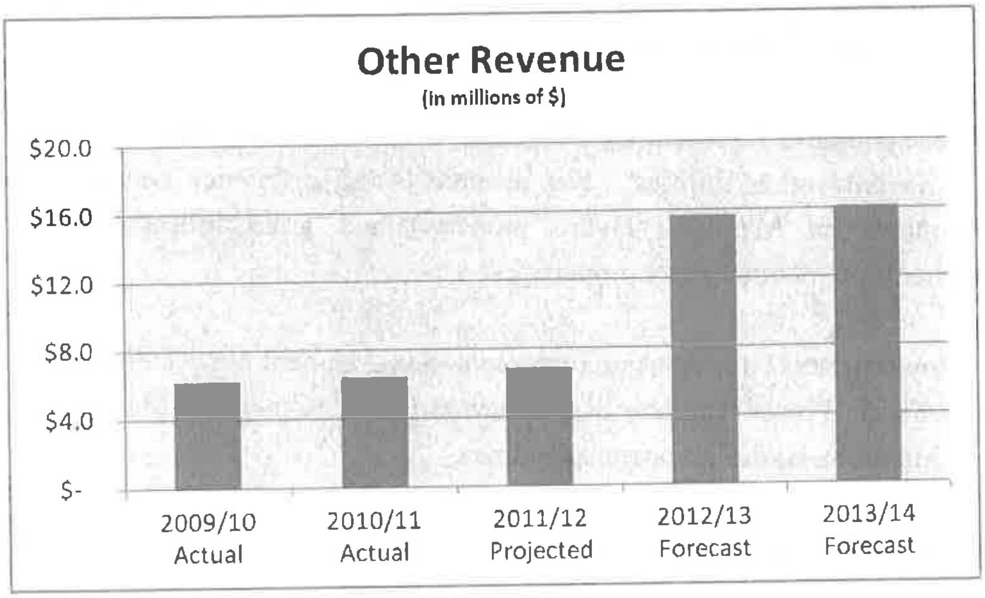
5.4 OTHER REVENUE

Other Revenue includes Joint Use contracts, revenue from Sask Power Island Falls, Hot Water Tank leasing, as well as other miscellaneous revenue.



Please see the following schedule for a breakdown of Other Revenue.

MANITOBA HYDRO
OTHER REVENUE

Schedule 5.4.0
(000's)

	2009/10 Actual	2010/11 Actual	2011/12 Projected	2012/13 Forecast	2013/14 Forecast
Operating Expense Recoveries	$ -	$ -	$ -	$ 8,300	$ 8,466
Joint Use	4,800	5,111	5,135	5,703	5,828
Island Falls Energy Transfer Agreement	902	862	661	819	884
Hot Water Tank	590	559	387	181	185
Other	(67)	(94)	666	703	715
Total Other Revenue	$ 6,226	$ 6,438	$ 6,849	$ 15,706	$ 16,078
Year over year $ change		$ 212	$ 412	$ 8,857	$ 372
Year over year % change		3.4%	6.4%	129.3%	2.4%

Please see the following for a description of other revenue components:

Operating expense recoveries are third party revenues where there is a provision of services for the use/rental of Manitoba Hydro owned assets. In addition, revenues (net of costs) received for work the Corporation undertakes on customer owned plant on a fee-for-service basis is also included.

Joint Use contracts represent the net rental revenue between Manitoba Hydro and MTS, Cable TV and other utilities. Net revenue is the difference between gross revenue (attachments on Manitoba Hydro property) and gross billings (Manitoba Hydro attachments on external party property).

Sask Power Island Falls revenue represents the agreement between Manitoba Hydro and Saskatchewan Power whereby Saskatchewan Power reimburses Manitoba Hydro for its use of Manitoba Hydro's transmission lines.

Hot water tank revenue represents the revenue from the Hot Water Tank leasing program.

Other miscellaneous revenue represents tenant revenue litigation settlements, rebates, etc.

The following sections highlight the year over year changes from 2009/10 through 2013/14:

2010/11 Actual vs. 2009/10 Actual
No significant change.

2011/12 Projected vs. 2010/11 Actual
The 2011/12 projected increase is primarily related to a 2010/11 settlement of an outstanding commitment to Ontario Power Generation.

2012/13 Forecast vs. 2011/12 Projected
The 2012/13 forecast increase is primarily attributable to a reclassification of Operating Expense Recoveries from OM&A to Other Revenue.

2013/14 Forecast vs. 2012/13 Forecast
The 2013/14 forecast increase is primarily due to general escalation.

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