November 2008

Manitoba Hydro

Integrated Financial Forecast (IFF08-1)

Financial Planning

Finance & Administration

2008/09 - 2018/19

Manitoba Hydro

TABLE OF CONTENTS
INTEGRATED FINANCIAL FORECAST (IFF08-1)

Section 1

KEY FINANCIAL RESULTS
(Dollars are in millions)

	Actual	IFF08-1 Forecast		
	2007/08	2008/09	2009/10	2010/11
PROJECTED RATE INCREASES - ELECTRIC - GAS (non-commodity)		 5.00% 1.00%	 4.00% 1.00%	 2.90% 1.00%
NET INCOME ($ Millions) - ELECTRIC - GAS	 $340 $6	 $308 $3	 $217 $3	 $177 $3
CAPITAL EXPENDITURES ($ Millions) - ELECTRIC - GAS	 $835 $34	 $1,013 $43	 $1,201 $47	 $1,086 $41
INTEREST COVERAGE RATIO	1.71	1.61	1.39	1.29
CAPITAL COVERAGE RATIO (excl. new major generation & transmission and new head office building)	1.60	1.76	1.07	1.15
DEBT/EQUITY RATIO	77:23	75:25	75:25	75:25

Note: In addition to the average rate increases projected for electric customers, General Consumers' Revenue also includes provisions for the new Energy Intensive Industrial Rate re-submitted to the Public Utilities Board in September, 2008.

1.0 OVERVIEW

1.1 INTRODUCTION

This Consolidated Integrated Financial Forecast (IFF08-1) projects Manitoba Hydro's financial results over the period 2008/09 to 2018/19 based on 2008 planning cycle assumptions regarding future energy demand and supply. Segmented forecasts prepared for the electricity (MH08-1) and natural gas (CGM08-1) operations are included. This forecast reflects the actual hydraulic conditions in the fall of 2008, new long term export sales agreements and the addition of the 630 MW Keeyask generating station for a targeted 2018/19 in-service date.

1.2 HIGHLIGHTS

- **Electricity Rates:** The base forecast includes the PUB-approved 5% rate increase effective July 1, 2008 and a further 4% conditional increase effective April 1, 2009 followed by projections of average rate increases of 2.9% per year beginning April 1, 2010 and every April 1 thereafter. Actual future rate applications to the PUB will be dependent upon the conditions of the day and subject to approval by the Board of Manitoba Hydro prior to filing.

- **Gas Rates:** The gas forecast includes the PUB-approved 1% average rate increase effective May 1, 2008, and general rate increases sufficient to generate net income of approximately $3 million in each of 2009/10 and 2010/11 (currently assumed to be 1% but will be dependent upon the cost of gas at the time of application). Thereafter, the forecast assumes 1% general rate increases effective April 1, of 2011, 2012, 2014 and 2018. The general rate increases projected for gas customers are intended to recover the distribution-related, non-commodity costs of operating the gas utility. As with electricity rate increases, these estimates are subject to future approvals.

- **Consolidated Net Income:** Consolidated net income is forecasted to reach $314 million in 2008/09, up $154 million from the $160 million forecasted in IFF07-1. The increase in net income is mainly attributable to higher export volumes due to current favourable water flow conditions and reductions to finance expense resulting from higher revenues and lower interest rates. Over the forecast period, net income is sufficiently improved to enable the debt/equity ratio to stay close to target even with substantial new capital investment.

- **Export Sales:** The forecast assumes new long term firm contracts with Minnesota Power and Wisconsin Public Service as well as a contract extension with Northern States Power.

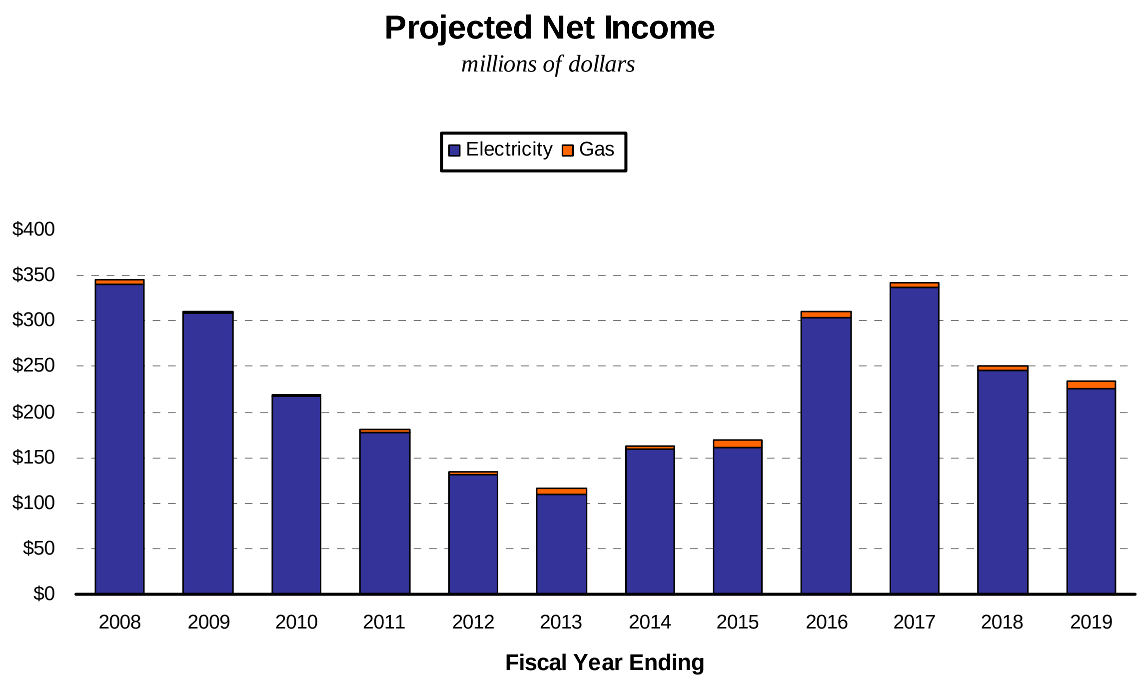
- **New Generation:** The Keeyask generating station (630 MW) is planned to come into service in 2018/19 in order to meet new export demands and domestic load growth. A draft partnership agreement, including equity ownership arrangements, has been submitted to the Tataskweyak, War Lake, Fox Lake and York Factory Cree Nations for community ratification over the next few months. Construction of the Wuskwatim generating station (200 MW) is proceeding, with the first unit planned to come into service in September, 2011. This forecast assumes that Nisichawayasihk Cree Nation will invest to acquire the maximum available 33% ownership interest in the generating station. Other assumptions related to hydraulic generation include the Conawapa generating station (1300 MW) first unit in-service in 2022/23 and the modernization of Pointe du Bois (from current 74 MW to 120 MW) by 2016/17.

- **New Major Transmission:** IFF08-1 assumes that the Bipole III HVDC line along with 2000 MW of converter capability at both north and south locations will be in service by 2017/18 for system reliability purposes and will accommodate future northern generation. A new 500 kV interconnection from Dorsey to the US border is planned for June, 2018 in order to meet the obligations of the new firm export sales.

- **The Capital Expenditure Forecast (CEF08-1):** The 2008 capital forecast, totalling $16.4 billion to 2018/19, is comprised of $11.5 billion of new major generation and transmission projects and $4.9

billion for other capital requirements including necessary system refurbishment and upgrades.

- **Projected net income for electricity and gas operations:** The following graph indicates projected levels of net earnings for Manitoba Hydro and the relative contributions made by each of the gas and electricity operations:



2.0 ASSUMPTIONS

2.1 ECONOMIC VARIABLES

The economic assumptions used in the forecast are based upon Manitoba Hydro's Spring 2008 Economic Outlook. Projected rates for key economic indicators are listed below with the previous projected rates in brackets.

	Manitoba Consumer Price Index	MH CDN New Short Term Debt Rate *	MH CDN New Long Term Debt Rate *	$US/$CDN Exchange Rate
2008/09	2.0% (2.0%)	3.50% (4.70%)	4.90% (5.60%)	1.02 (1.08)
2009/10	2.0% (2.0%)	4.05% (4.60%)	5.30% (5.75%)	1.06 (1.11)
2010/11	2.0% (2.0%)	4.60% (4.60%)	5.85% (5.95%)	1.06 (1.11)
2011/12	2.0% (2.0%)	4.60% (4.60%)	5.95% (6.10%)	1.07 (1.11)
2018/19	2.0% (2.0%)	4.60% (4.60%)	6.45% (6.45%)	1.10 (1.16)

*Excluding Provincial Guarantee Fee of 1.0%

Manitoba Hydro will be monitoring the global credit market crisis and how it may affect future interest rates, foreign exchange, load growth, capital and operating costs, and export market conditions.

2.2 IFRS - INTERNATIONAL FINANCIAL REPORTING STANDARDS

Manitoba Hydro will be required to produce IFRS compliant statements beginning with the 2011/12 fiscal year and provide comparative information for the 2010/11 fiscal year. While many aspects of IFRS are similar to Canadian Generally Accepted Accounting Principles, there are some areas that differ such as the capitalisation of overhead and the treatments of rate regulated assets. It is expected that the revised treatments will reduce the levels of expenditures that are deferred into future periods and will, therefore, cause an increase in current period costs which will, in turn, reduce net income and retained earnings over the short term. Manitoba Hydro is currently reviewing the accounting policy revisions necessary for the transition to these new standards and will be developing an implementation strategy over the next year. The forecast includes a provision for the adoption of the revised treatment of internally developed intangible assets, such as planning studies and DSM expenditures, effective April 1, 2009 as required under Canadian GAAP. For the years 2011/12 on, IFF08-1 includes provision for the more certain aspects of the conversion to IFRS in the amount of $25 million less offsets due to the corresponding reductions in depreciation and amortization expense. Areas which will require more detailed study will be reflected in subsequent forecasts.

2.3 US EXCHANGE EXPOSURE MANAGEMENT

Manitoba Hydro's Foreign Currency Exposure Management Program establishes an effective hedge between $US-denominated revenues and $US-denominated debt. Remaining $US inflows and outflows are valued at the market exchange rate. The exchange rate at year end is used for the balance sheet presentation of $US-denominated debt and investment instruments.

2.4 ELECTRICITY DEMAND AND SUPPLY

2.4.1 Manitoba Electricity Load Forecast

Relative to last year's forecast, the May 2008 Electric Load Forecast projects Manitoba electrical requirements to be 35 GW.h lower by 2017/18. Net total peak is forecast to be 1 MW higher. Significant growth is projected in the residential sector due to a higher population forecast and increased usage but this is largely offset by lower projected growth for general service customers.

Projected load growth in the general service class, (which represents 67% of all sales by volume) is lower even with higher growth in the primary metal sector. The reduction in overall growth is due to lower projected use in the chemical classifications and a reduced provision for potential large industrial loads.

General consumers' revenue includes the estimated impact of the proposed new marginal cost-based rate structure designed to encourage efficient use by new energy-intensive industrial loads which displace higher priced export sales. As this rate structure is related to actual marginal costs which change from time to time, it is not subject to projected general rate increases.

2.4.2 Extraprovincial Sales and Production Costs

Three new long term firm contracts have been included in this forecast (contracts under negotiation):

- Northern States Power contract extension (2015/16 to 2025/26) of 375 MW at 47.6% capacity factor, ramping up to 500 MW in 2022/23.
- Wisconsin Public Service (2018/19 to 2032/33) 66% capacity factor sale with capacity varying from 150 MW to 500 MW for various time periods.
- Minnesota Power (2022/23 to 2035/36) 250 MW at 66% capacity factor.

When combined with projected domestic load growth and existing export commitments, these new export agreements, which mostly occur outside of the IFF08-1 forecast period, necessitate the construction of the Keeyask and Conawapa generating stations and a 500 kV interconnection to the US.

Over the period to 2017/18, there is a projected increase in net export revenues of $508 million compared to the previous forecast. $242 million of this increase occurs in 2008/09 and 2009/10 and reflects current reservoir conditions and favourable market prices. The coal-fired Brandon unit #5 generation facility will be restricted in its operation throughout the forecast except during emergency conditions.

2.4.3 Demand Side Management

IFF08-1 includes DSM projections from the 2007 Power Smart Plan. Combined with savings achieved to date, the target for electrical savings is 807 MW / 2,759 GW.h by 2017/18. There is also a plan to achieve natural gas savings of 152 million cubic meters.

2.4.4 Electricity Supply

Manitoba Hydro’s 2008 Power Resource Plan describes the Corporation’s current expectations for new or enhanced major sources of electricity generation and HVDC transmission. The Power Resource Plan also provides projections of near-term retirement dates for existing facilities.

Major resource assumptions are shown in the table below. Keeyask is included in this forecast but was not in the plan for IFF07-1, while Conawapa is planned for one year later than in the previous forecast.

2008 Power Resource Plan			
	MW	**Dependable GW.h**	**In-Service Date**
Brandon #5 License Review	105	837	Restricted operation to 2018/19
Pointe du Bois	120	620	Rebuild by 2016/17
Wuskwatim	200	1,250	First power 2011
Keeyask	630	2,900	First power 2018
Conawapa	1300	4,550	First power 2022
Kelsey Re-runnering	77	-	All 7 units by 2011/12
Enhancements of Winnipeg River Plants	30	30	
HVDC Bipole III Line & 2000 MW of Converter Capability	89	243	2017/18
Northern AC Enhancements	45	-	
Demand Side Management Program			
Planned Additional	180	837	By 2017/18

2.4.5 Wuskwatim Partnership

The Wuskwatim Limited Partnership was established between Manitoba Hydro and Nisichawayasihk Cree Nation (NCN) to develop the Wuskwatim generating station. Construction of the infrastructure began in August 2006. The stage 1 cofferdam has been completed and significant progress has been made on excavation for the principal structures and channels. A number of major contracts have been awarded including the recent selection of a general civil contractor. Based on this bid, work is proceeding to achieve a nine month advancement of the first unit in-service to September, 2011. NCN may invest to acquire up to a 33% partnership interest in the generating station and finance up to 22% of project equity through loans from Manitoba Hydro.

Manitoba Hydro will purchase the output from the partnership under a power purchase agreement, and will construct, maintain and operate the Wuskwatim generating station and associated transmission. Manitoba Hydro's projected financial statements consolidate the partnership results, utilizing the non-controlling interest method of accounting for purposes of recording NCN's share of partnership net income. The partnership's net assets on the consolidated balance sheet are offset by an amount for NCN's non-controlling equity interest in the liability section of Manitoba Hydro's consolidated balance sheet. Manitoba Hydro's income statement reflects all of the revenues and costs related to the Wuskwatim partnership with NCN's share of the project net income shown as a deduction before net income.

3.0 NATURAL GAS DEMAND AND SUPPLY

The Corporation sells primary gas to Manitobans in a market which also includes a small number of brokers and marketers, and is the gas distribution utility for all customers in Manitoba. Currently, approximately 80% of customers representing approximately 60% of volumes purchase their primary gas requirements from Manitoba Hydro, with the balance using brokers and marketers through the Western Transportation Service.

The 2009 Natural Gas Volume Forecast is slightly higher than last year's forecast. The total natural gas sales volume forecast is up 13 million cubic meters (0.6%) in 2008/09 and up 20 million cubic meters (1.0%) in 2009/10. By 2017/18, the forecast is up 23 million cubic meters (1.1%). The Large General Service and Special Contract volume forecasts are expected to increase due to a combination of the increased usage experienced in 2007/08 and the use of a higher weather-adjusted base. The volume forecast increase is offset by lower consumption expectations of various manufacturing facilities in the Industrial sector.

The forecast incorporates the transportation and supplementary gas requirements, not only for Manitoba Hydro's customers but also for those consumers who purchase their primary gas from brokers and marketers.

There is no mark-up on primary gas but gas rates are structured to recover a portion of fixed costs through volume-based charges.

4.0 OPERATING & ADMINISTRATIVE EXPENSE

The operating forecast includes the necessary expenditures to provide for the safe and reliable operation and maintenance of the generation, transmission and gas and electric distribution systems.

Operating, Maintenance & Administrative (OM&A) Expenses in IFF08-1 are projected in total to be similar to those in the previous forecast with the addition of operating costs for the Keeyask generating station beginning in 2018/19. Overall, OM&A expenses are projected to increase by an average of 2.5% per year over the forecast period after including the projected requirements of both Wuskwatim and Keeyask. This rate of increase is lower than the combined total of projected inflation and customer load growth and will be achieved through continued productivity improvements.

5.0 CAPITAL EXPENDITURE FORECAST (CEF08-1)

CAPITAL EXPENDITURE FORECAST (CEF08-1) ($ in Millions)												
	2009	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**Total**
Electric	1,013	1,201	1,086	851	818	1,159	1,827	2,227	2,146	1,753	1,900	15,981
Gas	43	47	41	41	41	37	36	36	36	37	38	433
Total	**1,056**	**1,248**	**1,127**	**891**	**858**	**1,196**	**1,864**	**2,263**	**2,183**	**1,790**	**1,938**	**16,414**

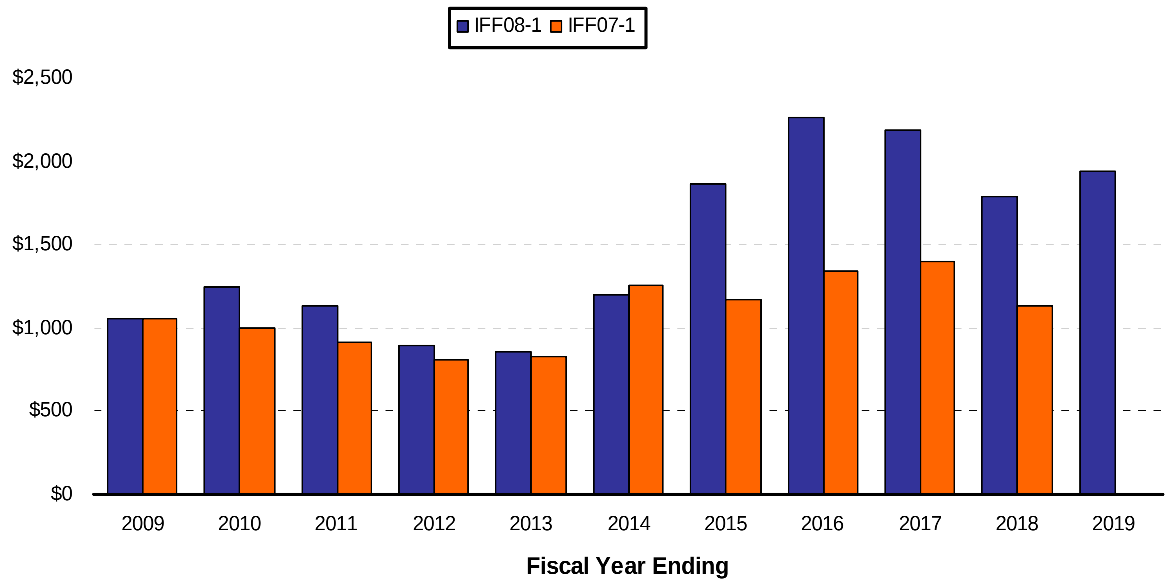
Projected capital expenditures for the period 2008/09 to 2018/19 total $16.4 billion. Over the first 10 years of the forecast, this is $3.6 billion higher than in CEF07-1 of which $2.9 billion relates to increases for major generation and transmission projects as referenced in the table below.

	10 Year Change in Forecast $ Millions	Total Project Cost $ Millions
Keeyask Generating Station	2,701	3,700*
Dorsey - US Border 500 kV T/L	201	205
Riel 230/500 kV Station	160	268
Dorsey 230 kV Relay Building	65	74
Kettle Transformer Overhauls	36	36
Power Supply Security Upgrades	26	36
New Head Office	25	278
Stanley 230-66 kV Transformer	21	21
Generation Townsite Infrastructure	20	52
Generation South Transformers	18	21
Wuskwatim Transmission	17	316
Slave Falls Rehabilitation	15	198
Conawapa Generating Station	(204)	4,978*
System refurbishment and other	477	
Total	**$3,578**	

* Under review

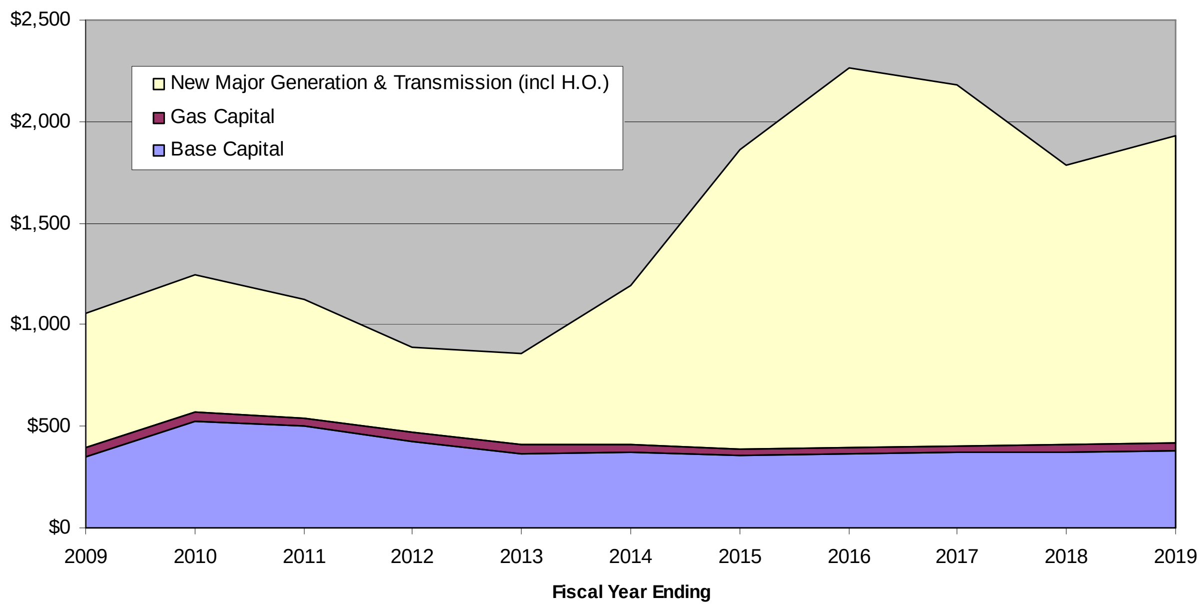
Projected Consolidated Capital Expenditures

millions of dollars



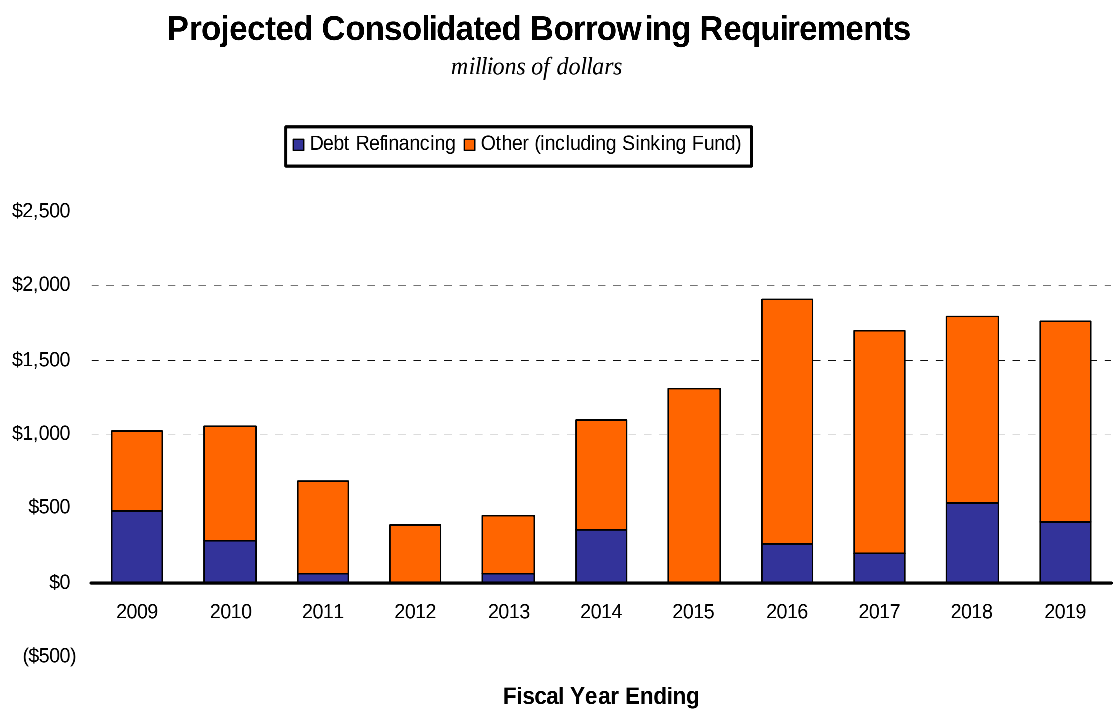
Projected Capital Expenditures
Major Categories

millions of dollars



6.0 BORROWING REQUIREMENTS

Manitoba Hydro's forecast borrowing requirements are portrayed in the following graph:



The Province of Manitoba issues long term debt directly on behalf of Manitoba Hydro. Both long and short-term borrowings are guaranteed by the Province. 15% to 25% of Manitoba Hydro's debt is held in floating rate instruments in order to minimize debt costs without undue interest rate exposure. Currently, about 21% of Manitoba Hydro's debt is in floating rate instruments.

7.0 FINANCIAL RATIOS

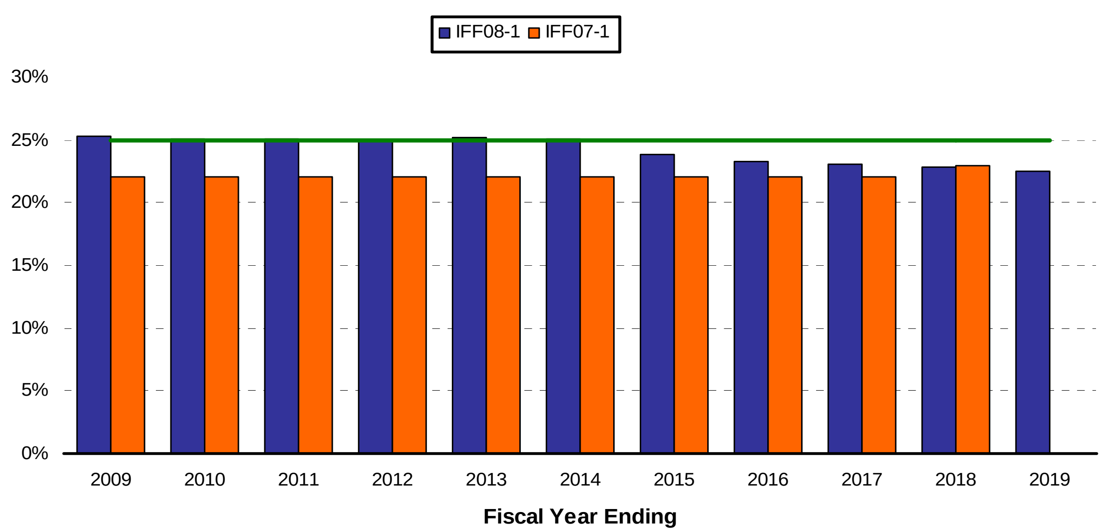
The following graphs depict the impact of IFF08-1, compared to IFF07-1, on Manitoba Hydro's financial targets.

Financial Targets	
Debt/Equity	Achieve a debt/equity ratio of 75:25 by 2011/12
Interest Coverage	Maintain a gross interest coverage ratio of at least 1.2
Capital Coverage	Maintain a capital coverage ratio greater than 1.0 (excluding new major generation and transmission & new head office building)

7.1 EQUITY RATIO

The equity ratio indicates the portion of Manitoba Hydro's capital structure that has been financed internally and not through debt financing. The current favourable water flow conditions are projected to result in the achievement of the Corporation's 75/25 debt equity ratio target by the end of 2008/09. Net income levels are projected to be sufficient to maintain this ratio at the target level until 2014/15 when capital expenditure levels begin to grow as a result of the construction of Keeyask, Conawapa and Bipole III.

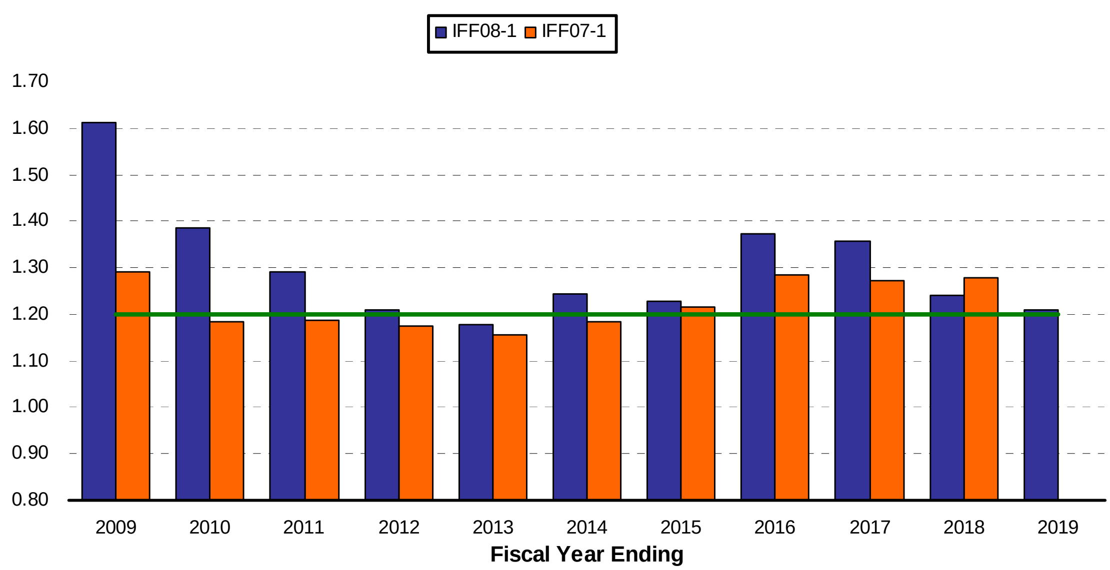
Projected Consolidated Equity Ratio



7.2 INTEREST COVERAGE RATIO

Interest coverage is measured by the ratio of the sum of gross finance expense plus net income to gross finance expense and provides an indication of the ability of the Corporation to meet interest payment obligations without the need for further borrowing. The effects of the current water flow conditions can be clearly seen in the level of interest coverage projected for 2008/09 with carryover effects into 2009/10. With the exception of a slight shortfall in 2012/13, the target level of 1.20 is projected to be met in all years of the forecast under assumed water flow conditions.

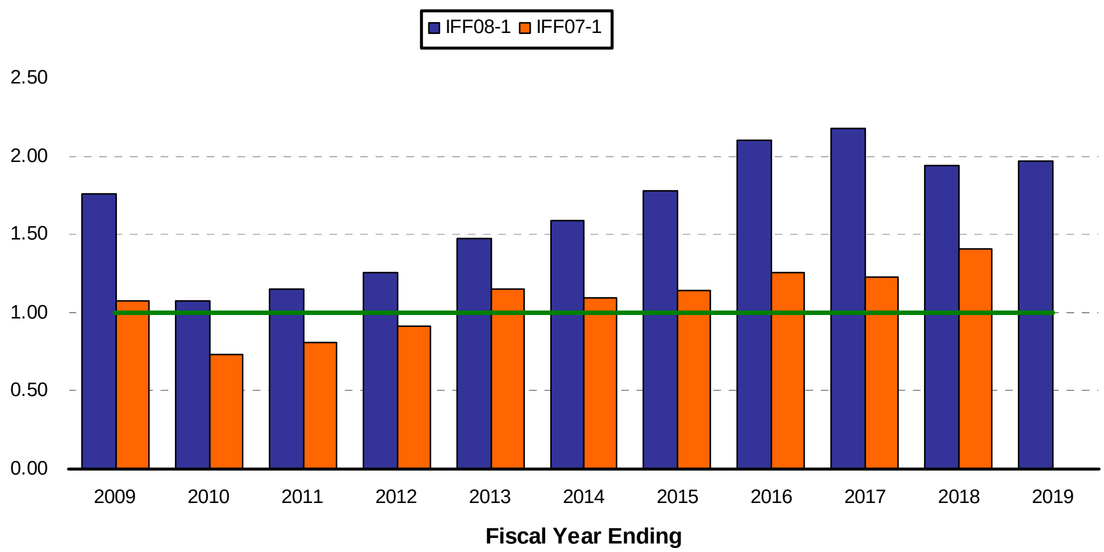
Projected Consolidated Interest Coverage Ratio



7.3 CAPITAL COVERAGE RATIO

Capital coverage measures the ability of current period internally generated funds to finance capital expenditures with the exception of major new generation, related transmission and the new head office. Projected net income levels are sufficient to enable this target to be met throughout the forecast period.

Projected Consolidated Capital Coverage Ratio



8.0 RISK ANALYSIS

Drought continues to be a risk of high significance in terms of both likelihood and consequence of occurrence. Manitoba Hydro typically derives over one third of its revenue from export sales and the potential loss of export revenue due to the adverse effects of a drought and/or other factors such as price declines, changes in regulation and increased domestic requirements is significant. Revenue losses are compounded by the additional costs to import power and operate thermal generation.

The impacts of export market and drought sensitivities, along with a number of other quantifiable risks and sensitivities, are shown in the table below. The table quantifies the resulting changes in retained earnings of the consolidated operations (IFF08-1) by the end of the forecast period 2018/19 assuming no change to rate increases from those in the base case and the annual rate increases/decreases relative to IFF08-1 necessary to offset the risks. Descriptions of the basis for the sensitivities follow.

	2010/11	2014/15	2018/19	Incremental Annual Rate Increase/(Decrease) *	
	Incremental Increase/(Decrease) in Retained Earnings (in millions of dollars)			Electric	Gas
IFF08-1 Baseline	**2,493**	**3,037**	**4,198**	**-**	**-**
+1% Interest Rates	32	27	(115)	0.18%	0.04%
-1% Interest Rates	(26)	13	214	-0.17%	-0.04%
Cdn $ down $0.10 US	53	126	258	-0.20%	N/A
Cdn $ up $0.10 US	(48)	(86)	(144)	0.20%	N/A
Low Export Prices	(64)	(408)	(936)	0.90%	N/A
High Export Prices	55	369	1,026	-1.18%	N/A
5 Year Drought	(485)	(2,651)	(3,488)	3.81%	N/A
+$100M & +$10M Capital Expenditures	(3)	(122)	(448)	0.54%	0.11%
Medium High Electric Load Forecast	(23)	(14)	(58)	0.13%	N/A

***NOTE** - the rate increases represent the additional identical annual percentage (incremental to the base case annual rate increases) required to achieve the same level of retained earnings in 2018/19 as in the base MH08-1 and CGM08-1.

Interest rates and foreign exchange

For the foreign exchange rate sensitivities, rates were adjusted beginning in fiscal year 2008/09. For the +/- 1% interest rate case and increase in capital spending scenarios, adjustments begin in 2009/10. In the +/- 1% interest rate case, the changes in rates were applied to all new long and short-term debt issues and to new sinking fund instruments For all other sensitivities, changes from MH08-1 and CGM08-1 begin in fiscal year 20010/11.

Export prices

Manitoba Hydro has developed an 'Expected' forecast of power prices for export which is assumed in the MH08-1 electricity forecast. In order to establish a reasonable set of bounds to cover the likely range of export prices, Low and High price forecasts have been developed based on industry research. Over the nine year period between 2010/11 and 2018/19, net export revenue would decline $746 million under the Low price forecast and increase $794 million under the High price forecast , before interest effects, compared to the Expected price forecast.

Manitoba load growth

The base load forecast used in MH08-1 represents the most likely future electricity requirements within the Province of Manitoba. Recent events suggest that load growth could be lower than forecast, but higher domestic load growth scenarios generally pose a greater financial risk to Manitoba Hydro. This is due to the reduction in high value export sales which are used to keep rates low, as well as the need to ensure that sufficient resources are available to meet the additional load requirements.

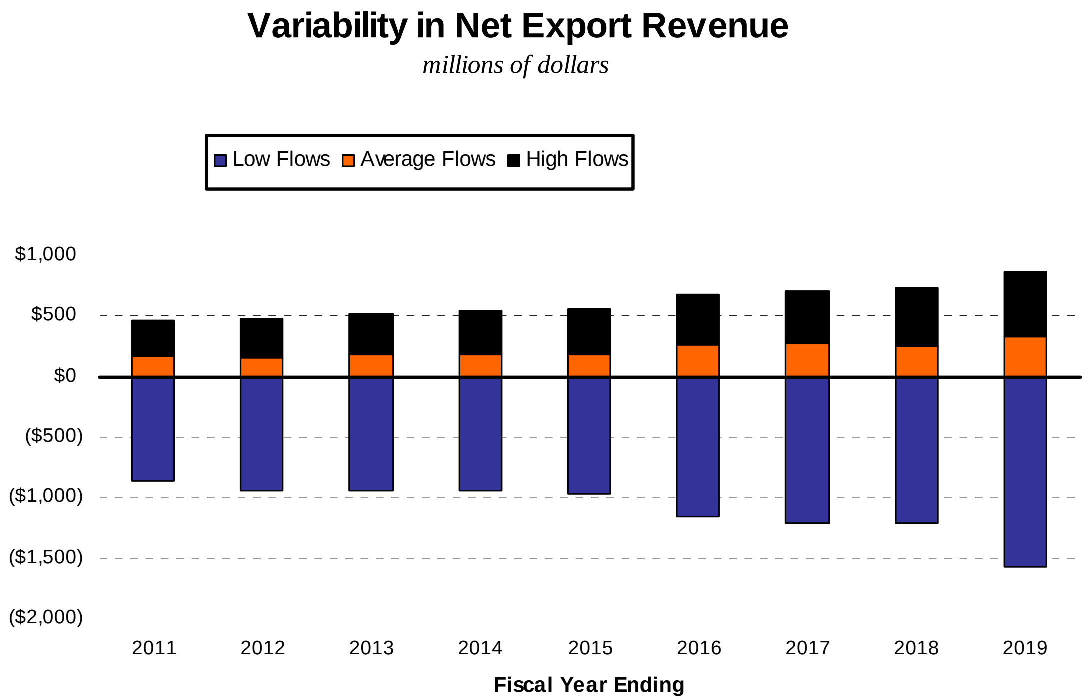
Increase in Capital Expenditures

Sensitivities have been performed on capital spending for both gas and electricity operations to reflect the increased financial risk faced by the Corporation in the area of continued upward pressure on capital project construction costs, and/or additional expenditures to meet reliability, safety, regulatory or customer requirements. Increases in general infrastructure requirements of $100 million per year for electricity operations and $10 million per year for gas operations have been assumed for this sensitivity.

Water conditions

Historically, droughts of varying degrees of severity have occurred about once every ten years. The onsets of droughts are very unpredictable and their range in impact can vary significantly. A drought sensitivity has been prepared based on an assumed recurrence of the worst five year drought on record. This drought sensitivity replicates the water flows of the historic five year drought period between April 1987 and March 1992 beginning in the forecast year 2010/11 and extending to 2014/2015. The impacts of the drought on export revenues and thermal and import costs, assume expected market conditions. Over the five year drought period, net export revenue would be reduced by $2.2 billion compared to IFF08-1. The impact could be greater due to financing costs and will be dependent upon the timing and magnitude of the rate increases implemented to address the drought impacts. If a drought of this magnitude (or the even larger 1936 - 1943 drought) were to coincide with a period of high prices for thermal and import purchases the impact would be even greater.

The graph below shows the variability in net export revenues on an annual basis due to fluctuations in water flows. The asymmetry between the benefits of high flows and the costs of low flows is due to the fact that in high years, water is spilled as a result of system design constraints and to the requirements for thermally generated and imported energy under low water years.



From a financial perspective, Manitoba Hydro's best risk protection is achieved through adequate levels of equity (retained earnings). Equity provides a buffer to absorb adverse events so that compensating rate increases can be smoothed out over a period of time. The Corporation is exposed to a number of other uncertainties which must be managed including risks related to reliability of service, infrastructure loss, environmental, and regulatory/legal issues. The magnitude of their impact and relative probability of occurrence are outlined in Manitoba Hydro's Corporate Risk Management report.

Section 2

9.0 PROJECTED CONSOLIDATED FINANCIAL STATEMENTS (IFF08-1)

CONSOLIDATED PROJECTED OPERATING STATEMENT (IFF08-1)
(In millions of Dollars)

For year ending March 31:	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
REVENUES											
General Consumers Revenue	1,678	1,803	1,890	1,958	2,021	2,068	2,125	2,179	2,234	2,301	2,371
Extraprovincial	619	546	465	477	498	509	524	624	649	651	800
Other	32	25	26	27	27	28	28	29	29	30	30
	2,330	2,373	2,381	2,461	2,546	2,605	2,677	2,831	2,912	2,982	3,201
EXPENSES											
Finance Expense	434	461	470	517	579	553	568	541	553	629	733
Operating & Administrative	418	428	436	452	461	470	479	490	499	522	534
Depreciation & Amortization	377	404	424	470	500	508	526	533	535	566	607
Water Rentals & Assessments	121	112	107	110	113	114	114	115	116	116	121
Fuel & Power Purchased	149	198	199	213	210	226	240	252	267	291	354
Capital & Other Taxes	89	95	98	98	101	105	112	122	131	137	145
Cost of Gas Sold	427	450	463	463	461	460	459	457	456	455	454
	2,016	2,149	2,197	2,324	2,426	2,437	2,500	2,510	2,557	2,717	2,949
Noncontrolling Interest	0	0	0	2	2	(0)	(2)	(5)	(7)	(9)	(12)
Net Income	314	224	184	140	122	168	175	316	348	256	240
Additional General Consumers Revenue											
General electricity rate increases		4.00%	2.90%	2.90%	2.90%	2.90%	2.90%	2.90%	2.90%	2.90%	2.90%
General gas rate increases		1.00%	1.00%	1.00%	1.00%	0.00%	1.00%	0.00%	0.00%	0.00%	1.00%
Financial Ratios											
Debt	75%	75%	75%	75%	75%	75%	76%	77%	77%	77%	77%
Interest Coverage	1.61	1.39	1.29	1.21	1.18	1.24	1.23	1.37	1.36	1.24	1.21
Capital Coverage	1.76	1.07	1.15	1.26	1.47	1.59	1.78	2.10	2.17	1.94	1.96

CONSOLIDATED PROJECTED BALANCE SHEET (IFF08-1)
(In millions of Dollars)

For year ending March 31:	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
ASSETS											
Plant in Service	12,567	13,128	13,686	15,759	16,299	16,707	17,421	17,817	19,015	21,694	22,895
Accumulated Depreciation	(4,527)	(4,892)	(5,272)	(5,690)	(6,140)	(6,597)	(7,071)	(7,547)	(8,032)	(8,550)	(9,112)
Net Plant in Service	8,039	8,236	8,414	10,069	10,160	10,110	10,350	10,269	10,983	13,144	13,784
Construction in Progress	1,663	2,314	2,831	1,576	1,875	2,650	3,786	5,635	6,604	5,702	6,407
Current & Other Assets	2,509	2,368	2,311	2,410	2,499	2,250	2,429	2,737	2,910	3,210	3,058
Goodwill	107	107	107	107	107	107	107	107	107	107	107
	12,319	13,024	13,663	14,163	14,641	15,117	16,672	18,748	20,605	22,163	23,357
LIABILITIES											
Long Term Debt	7,170	7,859	8,632	8,968	8,391	9,611	10,766	12,567	13,653	14,602	15,994
Current & Other Liabilities	2,356	2,269	1,947	2,045	2,978	2,099	2,344	2,321	2,762	3,127	2,689
Contributions in Aid of Construction	393	394	396	397	400	402	408	415	422	430	438
Retained Earnings	2,136	2,309	2,493	2,573	2,695	2,863	3,037	3,353	3,702	3,957	4,198
Accumulated Other Comprehensive Income	264	193	196	179	179	143	117	92	66	47	38
	12,319	13,024	13,663	14,163	14,641	15,117	16,672	18,748	20,605	22,163	23,357
Debt Ratio	75%	75%	75%	75%	75%	75%	76%	77%	77%	77%	77%

CONSOLIDATED PROJECTED CASH FLOW STATEMENT (IFF08-1)
(In millions of Dollars)

For year ending March 31:	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
OPERATING ACTIVITIES											
Cash Receipts from Customers	2,427	2,462	2,469	2,550	2,630	2,689	2,761	2,915	2,996	3,065	3,285
Cash Paid to Suppliers and Employees	(1,262)	(1,387)	(1,383)	(1,437)	(1,447)	(1,472)	(1,503)	(1,534)	(1,569)	(1,623)	(1,712)
Interest Paid	(487)	(477)	(465)	(520)	(586)	(568)	(556)	(553)	(564)	(669)	(775)
Interest Received	29	30	20	11	14	13	2	13	24	34	37
	708	628	642	604	612	663	704	842	887	808	835
FINANCING ACTIVITIES											
Proceeds from Long Term Debt	800	990	800	400	320	1,200	1,400	2,000	1,600	1,800	1,800
Sinking Fund Withdrawals	251	262	238	29	85	486	0	6	0	0	440
Retirement of Long Term Debt	(735)	(541)	(302)	(29)	(147)	(839)	0	(262)	(201)	(530)	(853)
Other	(8)	(16)	(8)	26	(5)	(9)	(10)	(11)	(11)	(12)	(24)
	308	695	727	426	253	838	1,390	1,734	1,388	1,257	1,363
INVESTING ACTIVITIES											
Property, Plant & Equipment, net of contributions	(1,112)	(1,265)	(1,138)	(901)	(865)	(1,203)	(1,868)	(2,268)	(2,188)	(1,795)	(1,942)
Sinking Fund Payment	(103)	(102)	(99)	(98)	(113)	(171)	(108)	(194)	(154)	(234)	(193)
Other	(20)	(20)	(20)	(16)	(16)	(26)	(26)	(26)	(26)	(27)	(27)
	(1,235)	(1,387)	(1,257)	(1,014)	(994)	(1,400)	(2,002)	(2,488)	(2,368)	(2,055)	(2,162)
Net Increase (Decrease) in Cash	(219)	(65)	113	15	(130)	100	92	88	(92)	10	37
Cash at Beginning of Year	123	(96)	(161)	(48)	(32)	(162)	(62)	30	117	25	35
Cash at End of Year	(96)	(161)	(48)	(32)	(162)	(62)	30	117	25	35	72

10.0 CAPITAL EXPENDITURE FORECAST (CEF08-1)

PROPOSED CAPITAL EXPENDITURES FORECAST (CEF08-1)

(In Millions of Dollars)

	Project Cost	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	11 Year Total
ELECTRIC													
MAJOR GENERATION & TRANSMISSION													
Wuskwatim Generation	1 274.6	200.6	326.9	256.4	126.8	20.8	-	-	-	-	-	-	931.5
Wuskwatim Transmission	315.5	117.4	52.5	32.2	15.5	0.9	-	-	-	-	-	-	218.6
Herblet Lake - The Pas 230 kV Transmission	93.2	16.1	39.3	29.0	4.2	-	-	-	-	-	-	-	88.6
Keeyask Generating Station	3 700.4	56.6	25.9	33.1	36.1	64.3	220.3	430.6	687.9	704.1	504.9	444.8	3 208.7
Conawapa Generating Station	4 978.4	58.9	60.5	60.7	57.7	62.3	67.7	261.8	356.3	330.7	609.4	1 044.6	2 970.5
Kelsey Generating Station Improvements & Upgrades	189.6	43.4	45.8	7.4	0.3	-	-	-	-	-	-	-	96.9
Kettle Generating Station Improvements & Upgrades	75.6	0.4	7.0	7.3	6.4	6.0	3.8	3.7	6.1	6.4	4.0	3.8	54.8
Pointe du Bois Rebuild	818.0	13.0	13.8	14.8	15.5	91.5	141.1	310.7	105.0	94.8	4.0	-	804.3
Pointe du Bois & Slave Falls Transmission	85.9	7.9	19.1	12.5	13.2	16.4	13.0	2.8	-	-	-	-	84.9
Planning Study Costs		5.7	5.9	4.7	-	-	-	-	-	-	-	-	16.3
Bipole 3 Western Route	2 247.8	9.2	16.6	21.4	36.7	113.4	266.5	420.2	627.7	557.9	168.6	-	2 238.3
Riel 230/ 500 kV Station	267.6	4.2	30.7	68.8	75.7	43.5	36.4	4.7	-	-	-	-	264.0
Firm Import Upgrades	4.8	0.1	0.4	2.1	2.1	-	-	-	-	-	-	-	4.8
Dorsey - US Border New 500kV Transmission Line	204.8	-	-	-	0.8	1.8	10.7	11.8	56.7	58.5	61.0	3.4	204.8
Demand Side Management - Electric		42.7	34.6	33.3	31.8	29.4	26.0	26.6	25.4	25.2	24.8	20.3	320.2
MAJOR GENERATION & TRANSMISSION TOTAL		**576.3**	**679.1**	**583.6**	**422.9**	**450.2**	**785.6**	**1 472.9**	**1 865.2**	**1 777.6**	**1 376.7**	**1 516.9**	**11 507.1**
NEW HEAD OFFICE													
New Head Office	**278.1**	**84.1**	-	-	-	-	-	-	-	-	-	-	**84.1**
CORPORATE RELATIONS													
Waterways Management Program		**5.2**	**5.3**	**5.5**	-	-	-	-	-	-	-	-	**16.0**

PROPOSED CAPITAL EXPENDITURES FORECAST (CEF08-1)

(In Millions of Dollars)

	Project Cost	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	11 Year Total
POWER SUPPLY													
Converter Transformer Bushing Replacement	5.9	0.1	1.3	1.0	-	-	-	-	-	-	-	-	2.4
Bipole 1 & 2 Electrode Line Monitoring	1.7	0.1	1.5	0.1	-	-	-	-	-	-	-	-	1.7
HVDC Auxiliary Power Supply Upgrades	3.7	0.1	-	-	-	-	-	-	-	-	-	-	0.1
Dorsey Synchronous Condenser Refurbishment	32.3	2.7	4.5	2.8	3.8	2.6	2.7	3.4	-	-	-	-	22.4
Dorsey ASEA Synchronous Condenser Cooler Upgrade	3.5	0.5	-	-	-	-	-	-	-	-	-	-	0.5
HVDC Bipole 1 Roof Replacement	5.9	0.4	0.7	-	-	-	-	-	-	-	-	-	1.0
HVDC System Transformer & Reactor Fire Protection & Prevent	10.4	1.1	1.1	0.6	-	-	-	-	-	-	-	-	2.8
HVDC AC Filter PCB Capacitor Replacement	34.5	5.3	3.0	4.7	-	-	-	-	-	-	-	-	13.0
HVDC Transformer Replacement Program	105.7	0.8	4.5	10.0 -	0.2	0.3	-	-	-	-	-	-	15.3
Dorsey 230KV Relay Building Upgrade	73.8	0.6	2.8	3.5	1.7	15.8	32.9	12.2	3.6	-	-	-	73.0
HVDC Stations Ground Grid Refurbishment	4.3	0.9	0.4	0.3	0.4	0.5	-	-	-	-	-	-	2.4
HVDC Bipole 2 230 kV HLR Circuit Breaker Replacement	9.4	2.9	1.3	0.8	0.3	-	-	-	-	-	-	-	5.3
HVDC Bipole 1 Pole Differential Protection	3.3	-	3.3	-	-	-	-	-	-	-	-	-	3.3
HVDC Bipole 1 By-Pass Vacuum Switch Removal	20.4	0.2	4.7	5.4	4.4	5.8	-	-	-	-	-	-	20.4
HVDC Bipole 2 Refrigerant Condenser Replacement	11.0	-	-	2.9	7.2	0.9	-	-	-	-	-	-	11.0
HVDC Bipole 1 Smoothing Reactor Replacement	31.8	0.3	3.1	10.5	12.8	5.1	-	-	-	-	-	-	31.8
HVDC - BP1 Converter Station, P1 & P2 Battery Bank Separatic	3.2	0.0	0.0	1.0	2.2	-	-	-	-	-	-	-	3.2
HVDC Bipole 1 DCCT Transductor Replacement	11.7	0.8	2.5	1.2	3.5	1.3	1.8	0.7	-	-	-	-	11.7
HVDC BP1 & BP2 DC Converter Transformer Bushing Replacem	8.7	-	0.5	1.0	1.6	5.1	0.5	-	-	-	-	-	8.7
HVDC Bipole 2 Valve Wall Bushing Replacements	19.2	-	3.4	4.6	4.7	4.8	1.8	-	-	-	-	-	19.2
HVDC Bipole 1 CQ Disconnect Replacement	5.2	-	0.0	1.2	1.6	0.9	1.1	0.3	-	-	-	-	5.2
HVDC - Bipole 2 Thyristor Module Cooling Refurbishment	4.7	0.4	1.8	1.8	0.8	-	-	-	-	-	-	-	4.7
HVDC BP2 Smoothing Reactor Replacement	17.1	-	-	-	7.0	6.5	3.0	0.5	0.1	-	-	-	17.1
Great Falls Generating Station Rehabilitation	31.1	0.2	-	-	-	-	-	-	-	-	-	-	0.2
Pine Falls Generating Station Rehabilitation	56.2	2.3	4.6	24.5	5.2	3.8	3.2	5.9	0.7	-	-	-	50.3
Laurie River GS Phase 2 & 3 Rehabilitation	7.7	-	-	1.0	0.8	1.2	-	-	-	-	-	-	3.0
Jenpeg Generating Station Unit Overhauls	128.1	0.1	-	-	-	-	-	-	2.4	2.6	19.1	25.1	49.3
Power Supply Dam Safety Upgrades	34.0	2.1	3.5	1.2	1.2	1.2	1.3	1.3	1.9	-	-	-	13.7
Winnipeg River Control System	10.4	0.7	-	-	-	-	-	-	-	-	-	-	0.7
Winnipeg River Riverbank Protection Program	19.7	1.3	1.1	1.2	1.2	1.2	1.2	1.3	1.3	1.5	-	-	11.3
Power Supply Hydraulic Controls	16.0	5.1	1.8	0.9	2.5	2.4	0.9	1.0	-	-	-	-	14.5
Slave Falls Rehabilitation	198.3	10.2	13.7	10.4	8.9	23.6	29.9	29.7	20.6	25.9	20.3	-	193.1
Generating Station Roof Replacements	9.2	3.9	-	-	-	-	-	-	-	-	-	-	3.9
Great Falls Unit 4 Overhaul	19.7	1.4	4.1	8.1	5.4	-	-	-	-	-	-	-	19.0
Great Falls 115 kV Indoor Station Safety Improvements	11.6	2.6	0.9	-	-	-	-	-	-	-	-	-	3.5
Generation South Transformer Refurbish & Spares	21.0	0.9	2.9	5.3	4.5	3.1	2.6	1.6	-	-	-	-	20.9
Water Licenses & Renewals	40.8	3.5	5.1	5.6	4.9	4.8	4.6	4.9	4.6	-	-	-	38.0
Generation South PCB Regulation Compliance	4.7	0.0	2.0	1.6	0.4	0.4	0.2	-	-	-	-	-	4.7
Kettle Transformer Overhaul Program	35.6	1.0	3.3	3.8	4.6	4.9	5.7	5.7	5.9	0.8	-	-	35.6
Generation South Breaker Replacements	9.4	1.6	2.5	0.9	2.8	1.6	-	-	-	-	-	-	9.4
Seven Sisters Generating Station Upgrades	9.5	1.3	3.5	2.5	1.2	1.0	-	-	-	-	-	-	9.5
Generation South Excitation Upgrades	18.3	-	-	2.0	3.2	3.9	3.3	3.2	2.7	0.1	-	-	18.3
Brandon Generating Station Unit 5 License Review	18.7	0.3	6.2	7.7	-	-	-	-	-	-	-	-	14.3
Selkirk Generating Station Enhancements	14.2	5.1	4.9	2.8	-	-	-	-	-	-	-	-	12.7
Fire Protection Projects - HVDC	5.2	2.0	2.5	-	-	-	-	-	-	-	-	-	4.5
Halon Replacement Project	42.5	11.0	19.2	11.0	0.4	-	-	-	-	-	-	-	41.6
Power Supply Fall Protection Program	13.5	2.6	-	-	-	-	-	-	-	-	-	-	2.6
Oil Containment - Power Supply	19.1	7.5	2.1	0.5	0.1	0.1	0.3	0.1	0.2	0.0	-	-	11.0
Generation Townsite Infrastructure	52.1	5.7	9.6	5.3	4.5	-	-	-	-	-	-	-	25.2
Site Remediation of Contaminated Corporate Facilities	30.9	1.4	0.7	0.5	0.4	0.3	-	-	-	-	-	-	3.4
High Voltage Laboratory	26.9	3.4	15.9	5.7	-	-	-	-	-	-	-	-	24.9
Power Supply Security Installations / Upgrades	36.3	6.1	21.4	7.4	-	-	-	-	-	-	-	-	35.0
Power Supply Sewer & Domestic Water System Instal / Upgr	15.1	6.2	4.1	1.6	1.3	-	-	-	-	-	-	-	13.2
Domestic Item - Power Supply		20.4	19.4	19.8	20.2	20.6	21.0	21.4	21.8	22.3	22.7	23.2	232.6
POWER SUPPLY TOTAL		**126.9**	**195.3**	**184.7**	**125.3**	**123.7**	**117.8**	**93.2**	**65.8**	**53.2**	**62.1**	**48.3**	**1 196.3**

PROPOSED CAPITAL EXPENDITURES FORECAST (CEF08-1)

(In Millions of Dollars)

	Project Cost	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	11 Year Total
TRANSMISSION & DISTRIBUTION													
Winnipeg - Brandon Transmission Improvements	40.0	2.3	1.4	1.6	3.6	3.7	5.2	22.0	-	-	-	-	39.8
Transcona New 230 - 66 kV Station	31.0	0.7	8.6	11.9	9.4	-	-	-	-	-	-	-	30.7
Neepawa 230 - 66 kV Station	30.0	0.2	5.8	11.3	12.8	-	-	-	-	-	-	-	30.0
Pine Falls - Bloodvein 115 kV Transmission Line	34.1	-	-	0.3	0.9	4.5	21.2	7.1	-	-	-	-	34.1
Transmission Line Re-Rating	24.1	4.4	0.4	0.4	-	-	-	-	-	-	-	-	5.2
Dorsey 230 kV Bus Enhancement	24.0	0.7	-	-	-	-	-	-	-	-	-	-	0.7
St Vital-Steinbach 230kV Transmission	32.2	-	-	-	-	-	-	-	0.9	1.0	2.6	5.1	9.5
Rosser Station 230 - 115 kV Bank 3 Replacement	5.8	2.9	2.4	-	-	-	-	-	-	-	-	-	5.3
Rosser - Inkster 115kV Transmission	5.1	2.8	2.2	-	-	-	-	-	-	-	-	-	5.0
Transcona Station 66kV Breaker Replacement	6.0	0.1	1.0	2.9	1.7	0.3	0.0	-	-	-	-	-	6.0
Transcona & Ridgeway Station 66kV Bus Upgrade	2.8	1.0	1.5	0.3	-	-	-	-	-	-	-	-	2.8
Dorsey 500kV R502 Breaker Replacement	2.6	2.3	0.4	-	-	-	-	-	-	-	-	-	2.6
Birtle South-Rossburn 66kV Line	4.9	-	-	-	-	-	0.1	0.3	4.5	-	-	-	4.9
Perimeter South Station Distribution Supply Centre Installation	2.4	0.1	0.3	2.0	-	-	-	-	-	-	-	-	2.4
Winnipeg Central District 66 kV Breaker Replacement	6.1	0.4	-	-	-	-	-	-	-	-	-	-	0.4
Stanley Station 230-66 kV Transformer Addition	21.1	-	-	-	-	1.9	8.4	7.9	2.9	-	-	-	21.1
Stanley Station 230-66kV Hot Standby	6.2	1.5	3.8	0.8	0.1	-	-	-	-	-	-	-	6.2
Defective RINJ Cable Replacement	8.7	1.1	1.1	1.0	-	-	-	-	-	-	-	-	3.1
Brereton Lake Station Area	9.0	1.0	0.2	-	-	-	-	-	-	-	-	-	1.2
Stony Mountain New 115 - 12 kV Station	5.0	1.2	-	-	-	-	-	-	-	-	-	-	1.2
Mobile Transformer	3.5	0.0	-	-	-	-	-	-	-	-	-	-	0.0
Rover Substation Replace 4 kV Switchgear	12.7	0.2	5.9	1.1	0.4	-	-	-	-	-	-	-	7.5
Martin New Outdoor Station	28.2	0.1	12.6	9.0	5.4	-	-	-	-	-	-	-	27.1
Frobisher Station Upgrade	14.4	7.6	2.9	0.0	-	-	-	-	-	-	-	-	10.5
Burrows New 66 kV/ 12 kV Station	28.6	4.6	10.7	10.2	2.4	-	-	-	-	-	-	-	27.9
Winnipeg Central District Oil Switch Project	7.1	2.8	0.5	-	-	-	-	-	-	-	-	-	3.3
William New 66 kV/ 12 kV Station	10.3	0.0	2.8	3.9	3.3	-	-	-	-	-	-	-	10.1
Waverley West Sub Division Supply - Stage 1	6.5	3.2	1.4	-	-	-	-	-	-	-	-	-	4.6
St. James 24 kV System Refurbishment	65.9	0.7	19.1	11.1	22.5	12.5	-	-	-	-	-	-	65.9
Transcona Area Distribution Conversion	4.4	0.7	-	-	-	-	-	-	-	-	-	-	0.7
Shoal Lake New 33 - 12.47 kV DSC	3.6	0.2	3.2	-	-	-	-	-	-	-	-	-	3.4
York Station	4.0	0.2	1.1	2.7	-	-	-	-	-	-	-	-	4.0
Brandon Crocus Plains 115 - 25 kV Bank Addition	6.3	0.1	0.8	3.1	1.8	0.4	-	-	-	-	-	-	6.3
Winkler Market Feeder M25-13 Conversion	2.9	2.9	-	-	-	-	-	-	-	-	-	-	2.9
Neepawa N Feeder NN12-2 & Line 57 Rebuild	1.9	0.0	1.9	-	-	-	-	-	-	-	-	-	1.9
Interlake Digital Microwave Replacement	19.7	7.4	3.9	-	-	-	-	-	-	-	-	-	11.3
Communication System Southern MB (Great Plains)	21.9	4.0	1.6	-	-	-	-	-	-	-	-	-	5.6
Communications Upgrade Wpg Area	7.4	1.1	0.8	-	-	-	-	-	-	-	-	-	1.9
Pilot Wire Replacement	9.6	1.5	0.4	1.1	0.9	-	-	-	-	-	-	-	3.9
Trans Line Protection & Teleprotection Replacement	21.1	1.9	2.0	5.7	6.4	2.4	1.2	0.3	-	-	-	-	19.8
Winnipeg Central Protection Wireline Replacement	9.3	2.5	2.4	1.2	-	-	-	-	-	-	-	-	6.1
Mobile Radio System Modernization	30.7	0.1	0.5	13.9	16.2	-	-	-	-	-	-	-	30.7
Gas SCADA Replacement	4.6	0.4	1.1	3.1	-	-	-	-	-	-	-	-	4.6
Cyber Security Systems	10.1	4.0	2.8	0.6	-	-	-	-	-	-	-	-	7.4
Site Remediation	13.3	1.0	3.1	2.0	0.3	-	-	-	-	-	-	-	6.5
Oil Containment	7.4	1.8	1.3	-	-	-	-	-	-	-	-	-	3.1
Station Battery Bank Capacity & System Reliability Increase	46.5	4.9	6.9	7.0	6.7	6.7	3.9	3.6	-	-	-	-	39.6
Red River Floodway Expansion Project	1.8	0.5	-	-	-	-	-	-	-	-	-	-	0.5
Fleet	39.8	13.0	13.3	13.5	13.8	14.1	14.3	14.6	14.9	15.2	15.5	15.8	158.1
Domestic Item - Transmission & Distribution Electric		88.9	90.7	92.6	94.4	96.3	98.2	100.2	102.2	104.2	106.3	108.4	1 082.5
TRANSMISSION & DISTRIBUTION TOTAL		**178.9**	**222.8**	**214.2**	**203.0**	**142.7**	**152.6**	**155.9**	**125.3**	**120.4**	**124.5**	**129.4**	**1 769.8**

PROPOSED CAPITAL EXPENDITURES FORECAST (CEF08-1)

(In Millions of Dollars)

	Project Cost	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	11 Year Total
CUSTOMER SERVICE & MARKETING													
Automatic Meter Reading	30.9	-	3.9	4.0	4.0	4.1	4.3	4.3	4.5	-	-	-	29.1
Distribution PCB Testing & Transformer Replacement	19.6	0.4	-	-	-	-	-	-	-	-	-	-	0.4
Winnipeg Distribution Infrastructure Requirements	14.9	2.0	1.8	-	-	-	-	-	-	-	-	-	3.8
Winnipeg Central District Underground Network Asbestos Removal	3.0	0.8	0.8	-	-	-	-	-	-	-	-	-	1.5
Domestic Item - Customer Service & Marketing - Electric		60.2	61.4	62.6	63.9	65.2	66.5	67.8	69.1	70.5	71.9	73.4	732.5
CUSTOMER SERVICE & MARKETING TOTAL		**63.3**	**67.9**	**66.6**	**67.9**	**69.2**	**70.7**	**72.1**	**73.6**	**70.5**	**71.9**	**73.4**	**767.3**
FINANCE & ADMINISTRATION													
Corporate Buildings	-	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	88.0
Enterprise GIS Project	21.9	0.4	-	-	-	-	-	-	-	-	-	-	0.4
Workforce Management (Phase 1 to 4)	11.3	6.7	-	-	-	-	-	-	-	-	-	-	6.7
WorkSmart	5.4	0.9	-	-	-	-	-	-	-	-	-	-	0.9
Domestic Item - Finance & Administration		22.3	22.7	23.2	-	24.1	24.6	25.1	25.6	26.1	26.6	27.2	271.2
FINANCE & ADMINISTRATION TOTAL		**38.3**	**30.7**	**31.2**	**31.7**	**32.1**	**32.6**	**33.1**	**33.6**	**34.1**	**34.6**	**35.2**	**367.2**
CAPITAL INCREASE PROVISION		-	-	-	-	-	-	-	**63.1**	**90.4**	**82.8**	**97.3**	**333.6**
ELECTRIC CAPITAL SUBTOTAL		**1 073.2**	**1 201.2**	**1 085.8**	**850.7**	**817.9**	**1 159.4**	**1 827.2**	**2 226.6**	**2 146.2**	**1 752.7**	**1 900.4**	**16 041.4**
GAS													
TRANSMISSION & DISTRIBUTION													
Southloop Capacity Upgrade - Winkler	4.3	3.6	-	-	-	-	-	-	-	-	-	-	3.6
Gas Riser Rehabilitation Program	16.5	2.0	-	-	-	-	-	-	-	-	-	-	2.0
Natural Gas Pipeline Replacement Red River at North Perimeter	1.7	1.6	-	-	-	-	-	-	-	-	-	-	1.6
Brandon Unodourised Pipeline Improvement	5.5	0.3	5.2	-	-	-	-	-	-	-	-	-	5.5
Domestic Item - Transmission & Distribution Gas		15.2	17.2	17.5	17.9	18.3	18.6	19.0	19.4	19.8	20.2	20.6	203.5
TRANSMISSION & TRANSMISSION TOTAL		**22.8**	**22.4**	**17.5**	**17.9**	**18.3**	**18.6**	**19.0**	**19.4**	**19.8**	**20.2**	**20.6**	**216.3**
CUSTOMER SERVICE & MARKETING													
Automatic Meter Reading - Gas	15.0	-	3.7	3.7	3.5	3.8	-	-	-	-	-	-	14.7
Demand Side Management - Gas		13.5	14.2	13.3	12.4	11.5	10.7	10.1	9.5	9.1	7.0	4.5	115.8
Domestic Item - Customer Service & Marketing Gas		6.7	6.9	6.7	6.8	7.0	7.1	7.3	7.4	7.6	7.7	7.9	79.0
CUSTOMER SERVICE & MARKETING TOTAL		**20.2**	**24.7**	**23.7**	**22.8**	**22.3**	**17.8**	**17.4**	**16.9**	**16.7**	**14.7**	**12.4**	**209.5**
CAPITAL INCREASE PROVISION		-	-	-	-	-	-	-	-	-	**2.3**	**4.9**	**7.2**
GAS CAPITAL SUBTOTAL		**42.9**	**47.2**	**41.2**	**40.7**	**40.5**	**36.5**	**36.4**	**36.3**	**36.4**	**37.1**	**37.8**	**433.0**
CONSOLIDATED CAPITAL SUBTOTAL		**1 116.1**	**1 248.4**	**1 127.0**	**891.4**	**858.4**	**1 195.8**	**1 863.6**	**2 262.9**	**2 182.6**	**1 789.8**	**1 938.2**	**16 474.3**
CONSOLIDATED CAPITAL COST FLOW ADJUSTMENT		**(60.1)**											**(60.1)**
CONSOLIDATED CORPORATE TOTAL		**1 056.0**	**1 248.4**	**1 127.0**	**891.4**	**858.4**	**1 195.8**	**1 863.6**	**2 262.9**	**2 182.6**	**1 789.8**	**1 938.2**	**16 414.2**

11.0 ELECTRIC OPERATIONS INTEGRATED FINANCIAL FORECAST (MH08-1)

ELECTRIC OPERATIONS (MH08-1)
PROJECTED OPERATING STATEMENT
(In millions of Dollars)

For year ending March 31:	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
REVENUES											
General Consumers Revenue											
at approved rates	1,110	1,159	1,190	1,214	1,233	1,241	1,250	1,259	1,269	1,286	1,299
additional *	0	45	82	120	160	202	245	290	337	388	440
Extraprovincial	619	546	465	477	498	509	524	624	649	651	800
Other	15	7	7	8	8	8	8	8	8	8	8
	1,744	1,756	1,744	1,819	1,899	1,959	2,026	2,181	2,263	2,333	2,547
EXPENSES											
Finance Expense	399	425	432	479	542	516	531	503	515	591	695
Operating & Administrative	349	358	365	379	386	394	402	410	418	439	450
Depreciation & Amortization	351	374	390	432	462	470	488	496	498	529	570
Water Rentals & Assessments	121	112	107	110	113	114	114	115	116	116	121
Fuel & Power Purchased	150	199	199	214	211	226	241	252	268	292	354
Capital & Other Taxes	65	71	74	74	76	80	87	96	105	111	119
	1,436	1,539	1,567	1,689	1,791	1,800	1,864	1,873	1,920	2,078	2,309
Noncontrolling Interest	0	0	0	2	2	(0)	(2)	(5)	(7)	(9)	(12)
Net Income	308	217	177	132	110	159	160	303	336	246	226
*Additional General Consumers Revenue											
Percent Increase		4.00%	2.90%	2.90%	2.90%	2.90%	2.90%	2.90%	2.90%	2.90%	2.90%
Cumulative Percent Increase		4.00%	7.02%	10.12%	13.31%	16.60%	19.98%	23.46%	27.04%	30.72%	34.52%

ELECTRIC OPERATIONS (MH08-1)
PROJECTED BALANCE SHEET
(In millions of Dollars)

For year ending March 31:	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
ASSETS											
Plant in Service	12,018	12,545	13,078	15,128	15,642	16,025	16,714	17,090	18,263	20,913	22,082
Accumulated Depreciation	(4,406)	(4,755)	(5,117)	(5,522)	(5,954)	(6,394)	(6,849)	(7,312)	(7,777)	(8,276)	(8,816)
Net Plant in Service	7,612	7,790	7,960	9,607	9,687	9,632	9,866	9,778	10,486	12,638	13,266
Construction in Progress	1,658	2,312	2,829	1,574	1,873	2,648	3,784	5,633	6,602	5,700	6,406
Current & Other Assets	2,847	2,743	2,691	2,793	2,883	2,632	2,804	3,106	3,274	3,574	3,419
Goodwill	42	42	42	42	42	42	42	42	42	42	42
	12,160	12,887	13,523	14,016	14,486	14,954	16,495	18,559	20,404	21,954	23,133
LIABILITIES											
Long Term Debt	7,153	7,842	8,615	8,951	8,374	9,594	10,749	12,550	13,636	14,585	15,976
Current & Other Liabilities	2,248	2,188	1,868	1,967	2,902	2,023	2,268	2,245	2,686	3,051	2,613
Contributions in Aid of Construction	392	394	396	399	402	405	412	419	427	435	445
Retained Earnings	2,102	2,270	2,447	2,521	2,631	2,789	2,949	3,253	3,589	3,835	4,061
Accumulated Other Comprehensive Income	264	193	196	179	179	143	117	92	66	47	38
	12,160	12,887	13,523	14,016	14,486	14,954	16,495	18,559	20,404	21,954	23,133

ELECTRIC OPERATIONS (MH08-1)
PROJECTED CASH FLOW STATEMENT
(In millions of Dollars)

For year ending March 31:	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
OPERATING ACTIVITIES											
Cash Receipts from Customers	1,756	1,756	1,744	1,819	1,899	1,959	2,026	2,181	2,263	2,333	2,547
Cash Paid to Suppliers and Employees	(668)	(726)	(733)	(788)	(798)	(826)	(856)	(886)	(921)	(974)	(1,062)
Interest Paid	(463)	(452)	(437)	(491)	(558)	(540)	(528)	(525)	(537)	(641)	(747)
Interest Received	29	30	20	11	14	13	2	13	24	34	37
	655	608	594	550	557	607	643	783	830	752	775
FINANCING ACTIVITIES											
Proceeds from Long Term Debt	800	895	800	400	260	1,200	1,400	2,000	1,600	1,800	1,800
Sinking Fund Withdrawals	251	262	238	29	85	486	0	6	0	0	440
Retirement of Long Term Debt	(733)	(448)	(302)	(29)	(85)	(839)	0	(262)	(201)	(530)	(853)
Other	(8)	(15)	(7)	25	(5)	(9)	(11)	(11)	(11)	(12)	(24)
	310	694	728	425	255	838	1,389	1,734	1,388	1,257	1,363
INVESTING ACTIVITIES											
Property, Plant & Equipment, net of contributions	(1,067)	(1,217)	(1,096)	(859)	(824)	(1,166)	(1,831)	(2,231)	(2,151)	(1,757)	(1,904)
Sinking Fund Payment	(103)	(102)	(99)	(98)	(113)	(171)	(108)	(194)	(154)	(234)	(193)
Other	(20)	(20)	(20)	(16)	(16)	(26)	(26)	(26)	(26)	(27)	(27)
	(1,190)	(1,339)	(1,215)	(973)	(953)	(1,363)	(1,965)	(2,451)	(2,331)	(2,017)	(2,123)
Net Increase (Decrease) in Cash	(225)	(37)	107	3	(142)	81	68	66	(113)	(7)	16
Cash at Beginning of Year	130	(95)	(132)	(24)	(22)	(163)	(82)	(14)	51	(61)	(69)
Cash at End of Year	(95)	(132)	(24)	(22)	(163)	(82)	(14)	51	(61)	(69)	(53)

ELECTRIC OPERATIONS
COMPARISON OF MH08-1 TO MH07-1
INCREASE / (DECREASE)
(In millions of Dollars)

ACCOUNT	2009	CUMULATIVE 2009-2011	CUMULATIVE 2009-2018	VARIANCE EXPLANATION
REVENUES				
General Consumers Revenue Including Projected Rate Increases	(7)	21	205	5.0% July 1, 2008 and 4% April 1, 2009 rate increases, versus 2.9% April 1, 2008 & 2009 in previous forecast. Load growth lower in early years, higher in mid years. Lower projected Energy Intensive Industrial rate revenue.
Extraprovincial	151	329	169	Improved water flows in first two years. Higher export prices partially offset by strengthened Canadian dollar. Removal of 300 MW of new wind generation from forecast due to economic reasons.
Other	(7)	(37)	(153)	Revenue from subsidiaries now only included in consolidated operations. Increase in Joint Use revenue from MTS. Reduction in tenant revenue related to the new head office due to a reduction in downtown real estate lease rates.
Total Revenue	**136**	**313**	**221**	

ELECTRIC OPERATIONS
COMPARISON OF MH08-1 TO MH07-1
INCREASE / (DECREASE)
(In millions of Dollars)

ACCOUNT	2009	CUMULATIVE 2009-2011	CUMULATIVE 2009-2018	VARIANCE EXPLANATION
EXPENSES				
Finance Expense	(26)	(65)	(279)	Higher net income, lower interest rates in the early years of the forecast and strengthening of the Canadian dollar all reduce finance expense. Higher capital spending begins to offset finance expense in later years.
Operating & Administrative	(11)	(34)	(119)	O&A related to subsidiaries now reflected in consolidated operations
Depreciation & Amortization	4	39	310	DSM now amortized over 10 years rather than 15. Higher capital forecast. Inclusion of minimum IFRS provision.
Water Rentals & Assessments	9	13	6	Up in early years due to increased water flows.
Fuel & Power Purchased	7	23	(345)	Higher prices for thermal and import power purchases in early years. Reduction in power purchases due to the removal of 300 MW of wind from the forecast.
Capital & Other Taxes	2	11	66	Higher capital taxes and property tax assessments.
Total Expenses	**(15)**	**(13)**	**(362)**	
Non-controlling Interest	0	0	(46)	Higher export prices increase Wuskwatim net income and hence NCN's share.
Change in Net Income	**152**	**325**	**535**	

12.0 GAS OPERATIONS INTEGRATED FINANCIAL FORECAST (CGM08-1)

GAS OPERATIONS (CGM08-1)
PROJECTED OPERATING STATEMENT
(In millions of Dollars)

For year ending March 31:	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
REVENUES											
General Consumers Revenue											
at approved rates	570	594	607	606	605	604	602	601	600	599	598
additional revenue requirement *	0	6	12	18	23	23	29	29	29	29	35
	570	600	619	624	628	627	631	630	629	628	633
Cost of Sales	428	451	464	463	462	461	459	458	457	456	455
Gross Margin	142	149	155	161	166	166	172	172	172	172	178
Other Revenue	2	2	2	2	2	2	2	2	2	2	2
	144	151	157	163	168	168	174	174	174	174	180
EXPENSES											
Finance Expense	23	24	26	26	25	25	25	26	26	26	26
Operating & Administrative	58	59	60	62	63	64	65	67	68	69	71
Depreciation & Amortization	25	29	32	35	37	38	38	37	37	37	37
Capital & Other Taxes	23	24	24	24	24	25	25	25	25	26	26
Corporate Allocations	12	12	12	12	12	12	12	12	12	12	12
	141	148	154	159	161	164	165	167	168	170	172
Net Income	3	3	3	4	7	4	9	7	6	4	8
*Additional Revenue Requirement											
Percent Increase		1.00%	1.00%	1.00%	1.00%	0.00%	1.00%	0.00%	0.00%	0.00%	1.00%
Cumulative Percent Increase		1.00%	2.01%	3.03%	4.06%	4.06%	5.10%	5.10%	5.10%	5.10%	6.15%

GAS OPERATIONS (CGM08-1)
PROJECTED BALANCE SHEET
(In millions of Dollars)

For year ending March 31:	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
ASSETS											
Plant in Service	600	629	653	673	698	719	742	760	783	810	840
Accumulated Depreciation	(211)	(223)	(237)	(246)	(261)	(276)	(292)	(303)	(320)	(338)	(357)
Net Plant in Service	390	406	416	426	437	443	450	456	463	472	483
Construction in Progress	2	2	2	2	2	2	2	2	2	2	2
Current & Other Assets	248	253	255	252	248	243	238	234	230	225	219
	640	661	672	680	686	688	690	693	696	699	704
LIABILITIES											
Long Term Debt	143	238	238	175	235	235	235	235	235	235	235
Current & Other Liabilities	315	240	249	316	256	255	249	244	242	242	239
Contributions in Aid of Construction	30	30	29	28	27	26	26	25	24	24	23
Share Capital	121	121	121	121	121	121	121	121	121	121	121
Retained Earnings	30	33	36	40	46	51	59	67	73	77	86
	640	661	672	680	686	688	690	693	696	699	704

GAS OPERATIONS (CGM08-1)
PROJECTED CASH FLOW STATEMENT
(In millions of Dollars)

For year ending March 31:	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
OPERATING ACTIVITIES											
Cash Receipts from Customers	656	690	709	714	713	712	717	715	714	713	718
Cash Paid to Suppliers and Employees	(583)	(649)	(638)	(637)	(636)	(633)	(634)	(634)	(635)	(635)	(636)
Interest Paid	(24)	(26)	(28)	(29)	(28)	(28)	(28)	(28)	(28)	(28)	(28)
Interest Received	0	0	0	0	0	0	0	0	0	0	0
	49	15	43	48	49	50	55	53	52	50	54
FINANCING ACTIVITIES											
Proceeds from Long Term Debt	0	95	0	0	60	0	0	0	0	0	0
Retirement of Long Term Debt	(2)	(93)	0	0	(63)	0	0	0	0	0	0
Other	(0)	(1)	(1)	0	0	0	0	0	0	0	0
	(3)	1	(1)	0	(2)	0	0	0	0	0	0
INVESTING ACTIVITIES											
Property, Plant & Equipment, net of contributions	(43)	(48)	(42)	(41)	(41)	(37)	(37)	(37)	(37)	(38)	(38)
Other	0	0	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)
	(43)	(48)	(42)	(41)	(41)	(37)	(37)	(37)	(37)	(38)	(38)
Net Increase (Decrease) in Cash	3	(31)	1	7	6	14	18	16	15	12	15
Cash at Beginning of Year	(12)	(9)	(40)	(39)	(32)	(26)	(12)	6	22	37	48
Cash at End of Year	(9)	(40)	(39)	(32)	(26)	(12)	6	22	37	48	64

GAS OPERATIONS
COMPARISON OF CGM08-1 TO CGM07-1
INCREASE / (DECREASE)
(In millions of Dollars)

ACCOUNT	2009	CUMULATIVE 2009-2011	CUMULATIVE 2009-2018	VARIANCE EXPLANATION
REVENUES				
General Consumers Revenue Including Projected Rate Increases	14	112	509	Primarily due to higher gas prices. Slightly lower rate increases applied to higher base revenues.
Other	(0)	(1)	(4)	Lower late penalty charges as a result of the consolidation of customers' gas and electric bills.
Total Revenue	**14**	**111**	**505**	
EXPENSES				
Cost of Gas Sold	15	115	514	Primarily due to higher gas prices.
Finance Expense	(0)	2	(0)	Lower projected interest rates in the early part of the forecast. Partially offset by higher gas purchases and higher capital requirements.
Operating & Administrative	0	0	0	
Depreciation & Amortization	0	(1)	(4)	Lower due to a change in the treatment of the Furnace Replacement Program.
Capital & Other Taxes	0	1	4	Primarily due to higher property taxes.
Total Expenses	**15**	**117**	**514**	
Change in Net Income	**(1)**	**(6)**	**(9)**	