November 2010

Integrated Financial Forecast (IFF10)

2010/11 - 2019/20

Financial Planning
Finance & Administration

Manitoba Hydro

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KEY FINANCIAL RESULTS

(Dollars are in millions)

	Actual	IFF10 Forecast			
	2009/10	**2010/11**	**2011/12**	**2012/13**	**2019/20**
PROJECTED RATE INCREASES					
- ELECTRIC	2.9%	2.8%*	2.9%*	3.5%	3.5%
- GAS (non-commodity)	-	-	-	1.5%	1.0%
NET INCOME					
- ELECTRIC	$160	$149	$125	$120	$292
- GAS	($1)	$6	$4	$5	$4
- SUBSIDIARIES	$4	$4	$5	$6	$7
CAPITAL EXPENDITURES					
- ELECTRIC	$1 084	$1 082	1 028	$1 090	$2 175
- GAS	$33	$40	$40	$43	$39
DEBT/EQUITY RATIO	73:27	74:26	74:26	76:24	81:19
INTEREST COVERAGE RATIO	1.32	1.28	1.22	1.20	1.24
CAPITAL COVERAGE RATIO (excl. new major generation & transmission)	1.30	1.50	1.50	1.57	1.83
RETAINED EARNINGS	$2 239	$2 398	$2 531	$2 658	$4 331

*PUB approved interim rate increase effective April 1, 2010. Proposed 2.9% rate increase effective April 1, 2011 currently before the PUB.

1.0 INTRODUCTION

The Consolidated Integrated Financial Forecast (IFF10) projects Manitoba Hydro's financial results over the 10-year period 2010/11 to 2019/20. Segmented forecasts are also provided for the electricity (MH10), natural gas (CGM10), and corporate subsidiaries (CS10). The forecast reflects actual financial results and water storage as of September 2010.

1.1 HIGHLIGHTS

- **Electricity Rates:** The base forecast includes the 2.8% interim average rate increase effective April 1, 2010 and the 2.9% proposed average rate increase effective April 1, 2011. Consistent with last year's forecast, additional average rate increases of 3.5% per year are projected for April 1 each year from 2012/13 to 2019/20. Actual future rate applications to the Manitoba Public Utilities Board (PUB) will be dependent upon the conditions of the day and subject to approval by the Manitoba Hydro-Electric Board prior to filing.

- **Gas Rates:** The forecast assumes a 1.5% non-gas rate increase effective May 1, 2012. Subsequent non-gas rate increases of 1.0% are projected to be effective May 1, 2013 through 2016 and 2018 to 2019. Gas rate applications are also subject to review and approval of the Manitoba Hydro-Electric Board prior to filing with the PUB.

- **Consolidated Net Income:** Consolidated net income is projected to be $158 million in 2010/11, an increase of $70 million over the previous forecast IFF09. The increase is primarily due to higher export sales as a result of water storage carry-over from 2009/10 and above normal precipitation to the date of IFF10 preparation on October 19, 2010. Over the 10-year forecast period, net income is projected to increase by $247 million compared to IFF09 with higher net income in the early years mainly due to lower projected finance expense largely offset in the later years due to lower net export revenues and the projected one-year deferral of Keeyask.

- **Export Sales:** The forecast reflects the recently signed 10-year export contract with Northern States Power (NSP) of between 375 and 500 MW from 2015 to 2025. The forecast assumes that the term sheets negotiated for the 250 MW Minnesota Power and 500 MW Wisconsin Public Service long-term firm sales will be finalized into long-term firm contracts.

- **New Electricity Supply:** The first unit of the 200 MW Wuskwatim Generating Station is scheduled to be placed in service in late 2011 with the final unit scheduled to be in service by early 2012.

  Construction on the 138 MW wind farm near St. Joseph, owned by Pattern Energy, began in March, 2010 and is expected to be completed by January, 2011. Manitoba Hydro will purchase the output of the wind farm in accordance with a power purchase agreement signed in March 2010.

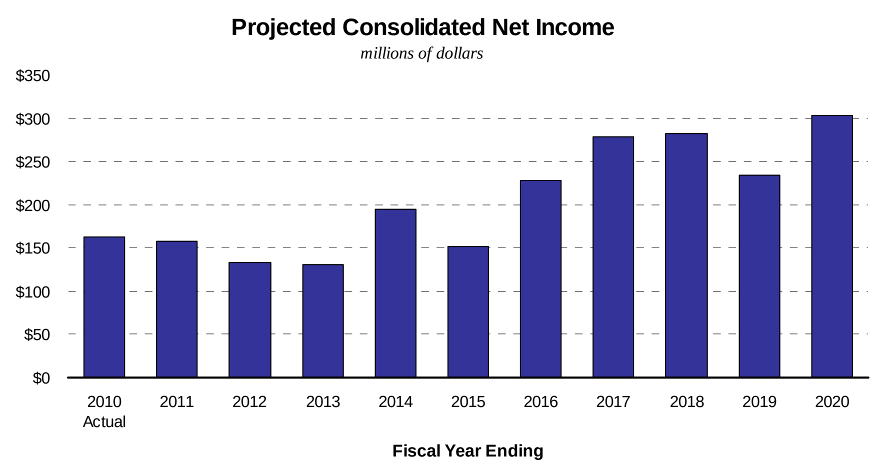
  Keeyask and Conawapa Generating Stations, are in the planning stage of development in order to meet the future energy requirements of the province and to take advantage of export market opportunities. Keeyask has a nominal capacity of 695 MW with a proposed in-service date of 2019/20 while Conawapa's proposed in-service date is 2023/24 with a nominal capacity of 1,485 MW. The projected in-service dates of both projects are deferred one year compared to IFF09.

- **New Major Transmission:** IFF10 includes a 1000 MW export and 750 MW import interconnection from Dorsey to the US border with a projected in service date in 2019/20 in order to meet the obligations of the new firm export sales.

  A new HVdc transmission line complete with converters , Bipole 3, is needed to improve system reliability and reduce dependency on Manitoba Hydro's existing HVdc facilities. Pending regulatory licensing and approvals the transmission line will originate at a new northern converter station site (Keewatinoow), will be routed southwesterly towards The Pas and southward generally west of Lakes Winnipegosis and Manitoba, terminating at a new converter station site (Riel) east of Winnipeg. Public consultations are expected to be completed in 2010 and the environmental impact statement is scheduled for submission to regulatory authorities in 2011. The proposed in-service date for Bipole III is 2017/18.

- **The Capital Expenditure Forecast (CEF10):** The 2010 capital forecast, totalling $16.9 billion to 2019/20, is comprised of $12.3 billion of new major generation and transmission projects and $4.6 billion for other capital requirements including necessary system refurbishment and upgrades. Compared to the same 10-year period in CEF09, the current forecast is higher by $1.6 billion.

- **Projected consolidated net income for electricity, gas and subsidiary operations:** The following graph indicates projected levels of net earnings for Manitoba Hydro.



2.0 ASSUMPTIONS

2.1 ECONOMIC VARIABLES

The economic assumptions used in the forecast are based upon Manitoba Hydro's Spring 2010 Economic Outlook revised in October for current economic conditions. Projected rates for key economic indicators are listed below with the 2009 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
2010/11	1.6% (1.9%)	1.10% (1.40%)	4.20% (4.65%)	1.02 (1.07)
2011/12	1.9% (2.0%)	2.10% (3.60%)	4.35% (5.20%)	1.02 (1.09)
2012/13	2.2% (2.0%)	3.30% (4.30%)	5.25% (5.70%)	1.04 (1.07)
2013/14	2.1% (2.0%)	3.85% (4.45%)	5.55% (6.10%)	1.05 (1.11)
2019/20	2.1% (2.0%)	4.65% (4.45%)	6.60% (6.10%)	1.11 (1.14)

*Excluding Provincial Guarantee Fee of 1.0%

2.2 US EXCHANGE EXPOSURE MANAGEMENT

Manitoba Hydro's Foreign Currency Exposure Management Program limits the exposure to US$ exchange rate fluctuations by establishing an effective hedge between $US-denominated revenues and $US-denominated debt. The exchange rate at year end is used for the balance sheet presentation of $US-denominated debt and investment instruments.

2.3 ELECTRICITY DEMAND AND SUPPLY

2.3.1 Manitoba Electricity Load Forecast

The 2010 Electric Load Forecast projects that Average annual growth is projected to be 1.6% for net firm energy and 1.4% for net total peak (compared to 1.5% and 1.3%, respectively, in IFF09) over the forecast period to 2019/20.

Net firm energy supplied to the Manitoba load is projected to grow from 23 962 GWh in 2010/11 to 27 856 GWh by 2019/20. Over that same 10-year period total system peak is projected to grow from 4 476 MW in 2010/11 to 5 140 MW in 2019/20. The system load factor is projected to remain relatively constant at approximately 61%.

2.3.2 Extraprovincial Sales and Production Costs

This past year, Manitoba Hydro signed agreements to extend its export commitments with Northern States Power (NSP) from 2014/15 to 2024/25. The sale agreements are subject to regulatory approvals from the Minnesota Public Utilities Commission and Canada’s National Energy Board. This forecast reflects the terms and conditions of the final NSP agreements.

As in the previous forecast, IFF10 includes the proposed sale of system power to Wisconsin Public Service (WPS) and Minnesota Power (MP) as set out in the term sheets signed in 2008 and 2007, respectively. Both proposed sales are contingent upon the construction of a new US interconnection and 1800 MW of new hydraulic generation, appropriate corporate and governmental approvals, regulatory and licensing approvals for the required facilities, and negotiation of definitive agreements. Due to the complexity of the arrangements, the proposed sales have been amended to delay the start date by one year shortening the duration of sales (end dates remain unchanged).

- Wisconsin Public Service sale from 2019/20 to 2032/33 (at 66% capacity factor) with capacity varying from 150 MW to 500 MW for various time periods.
- Minnesota Power sale from 2023/24 to 2035/36 of 250 MW (at 66% capacity factor).

Over the forecast to 2019/20, there is a projected decrease in net export revenues of $292 million compared to the previous forecast which is mainly attributable to the one year deferral of the Keeyask generating station. Lower export prices and a stronger projected Canadian dollar also contribute to the decrease.

2.3.3 Demand Side Management

IFF10 includes DSM projections from the 2010 Power Smart Plan to achieve the corporate target for further electrical savings of 626 MW and 2,133 GW.h by 2024/25. Combined with savings achieved to date, total electrical savings of 918 MW and 3,408 GW.h and total natural gas savings of 149 million cubic meters are forecast to be saved by 2024/25. These combined energy savings are expected to result in an overall reduction of greenhouse gas emissions of 2,584,400 tonnes by 2024/25.

2.3.4 Electricity Supply

Major resource assumptions are shown in the table below. Planned in-service for Keeyask and Conawapa are deferred one year from the previous forecast. The Pointe du Bois powerhouse rebuild has been deferred beyond the IFF period. This forecast assumes a new spillway and dam will be constructed at Pointe du Bois to replace existing spillway structures.

	MW	**Dependable GW.h**	**In-Service Date**
Brandon #5 License Review	105	811	Restricted operation to retirement date in 2018/19
Wuskwatim	200	1,250	2011/12
Keeyask	695	2,900	2019/20
Conawapa	1485	4,550	2023/24
Additional Wind Capacity	138	463	2010/11-2011/12
Kelsey Re-runnering	77	-	All 7 units by 2012/13
Enhancements of Winnipeg River Plants	30	30	
HVDC Bipole III Line & 2000 MW of Converter Capability	76	243	2017/18
Demand Side Management Program			
Planned Additional	275	1,112	By 2024/25

2.3.5 Wuskwatim Power Limited Partnership

The Wuskwatim Power Limited Partnership (WPLP) was formed to carry on the business of developing, owning, and operating the Wuskwatim Generating Station. The WPLP has two limited partners, Manitoba Hydro and Taskinigahp Power Corporation (TPC) which is beneficially owned by Nisichawayasihk Cree Nation (NCN) and a General Partner which is a wholly-owned subsidiary of Manitoba Hydro. NCN may 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.

Construction of the Wuskwatim Project commenced in August 2006 and is proceeding to achieve a scheduled first unit in-service in late 2011.

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 (with the exception of Swan River). Currently, approximately 87% of customers representing approximately 59% of volumes purchase their primary gas requirements from Manitoba Hydro, with the balance using brokers and marketers through the Western Transportation Service.

The 2010 Natural Gas Volume Forecast is lower than last year's forecast. The total natural gas sales volume forecast is down 22 million cubic meters (1%) in 2010/11 and down 56 million cubic meters (3%) in 2019/20. The 2010 forecast is lower as it includes all future DSM savings associated with the basic customer information and service and future DSM savings from all gas Power Smart programs. DSM savings assumptions are taken from the 2010 Power Smart Plan.

The volume forecast incorporates Manitoba Hydro's fixed price offering for primary gas, which was introduced in 2008/09 and offers customers one, three, and five-year fixed price contracts.

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.

4.0 OPERATING & ADMINISTRATIVE EXPENSE

Operating, Maintenance & Administrative (OM&A) Expenses in IFF10 include only those expenditures necessary to provide for the safe and reliable operation and maintenance of the generation, transmission and gas and electric distribution systems.

In response to the economic downturn, the Corporation has introduced a number of cost constraint measures. As a result of implementing these measures, base OM&A costs are forecast to decrease by 0.2% in 2010/11 compared to the previous year actual expenditures and by a further 0.9% in 2011/12.

Manitoba Hydro will also be implementing a number of IFRS-related accounting changes that will result in $21 million of costs that were previously capitalized being charged to operating expense in 2010/11. In addition, operating costs of the new Wuskwatim Generating Station are forecast to be $4 million in 2011/12 increasing to $9 million per year.

4.1 INTERNATIONAL FINANCIAL REPORTING STANDARDS (IFRS)

Manitoba Hydro will be required to adopt IFRS in place of Canadian generally accepted accounting principles (GAAP) for financial reporting purposes for its 2012/13 fiscal year (including comparative information for 2011/12). The 2012/13 transition period represents a one year deferral from the previous required transition period of 2011/12 and is a result of recent decisions made by the International and Canadian accounting standard setting bodies.

Manitoba Hydro has completed an assessment of the differences between Canadian GAAP and IFRS and is currently in the process of developing policy and process recommendations for the high impact accounting areas including accounting for property, plant and equipment, regulatory accounting and employee benefits. The forecast includes a provision of $15 million per year commencing in 2011/12.

5.0 CAPITAL EXPENDITURE FORECAST (CEF10)

CAPITAL EXPENDITURE FORECAST (CEF10)
(In Millions of Dollars)

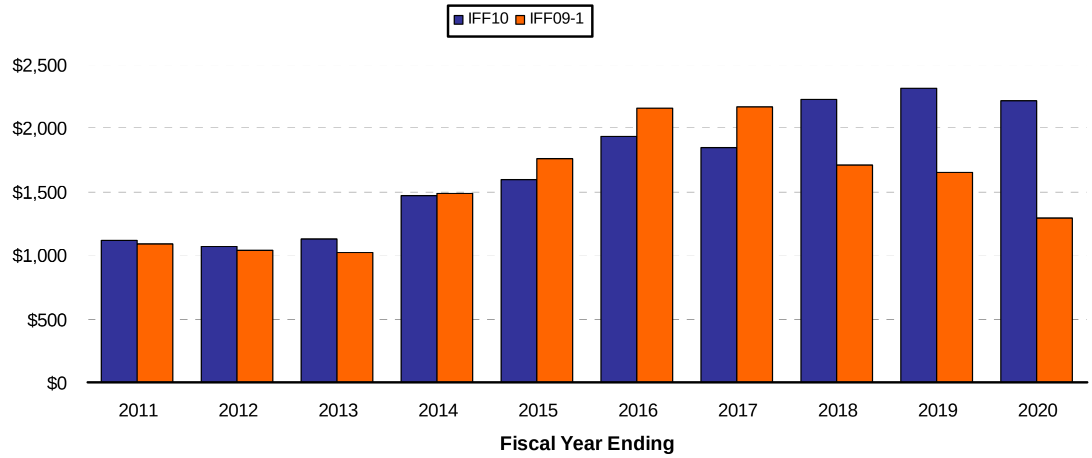
	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Total
New Major Generation & Transmission	747	689	740	964	1,110	1,473	1,368	1,744	1,814	1,706	12,354
Base Capital	433	451	439	460	452	430	440	450	458	469	4,482
Subtotal Electric	1,179	1,140	1,178	1,424	1,563	1,903	1,808	2,193	2,272	2,175	16,836
Gas	40	40	43	44	36	37	36	37	39	39	391
Target Adjustment	(97)	(111)	(88)	-	-	-	-	-	-	-	(296)
	1,122	1,069	1,133	1,469	1,599	1,940	1,845	2,231	2,311	2,214	16,931

Projected capital expenditures for the period 2010/11 to 2019/20 total $16.9 billion which is an increase of $1.6 billion from the level of capital expenditures in CEF09-1. Significant increases/(decreases) are summarized in the table below:

	Total Projected Cost	Total Project Increase	10 Year Increase (Decrease)
	($ Millions)		
Keeyask Generating Station	$ 5,637	$ 1,045	$ 924
Conawapa Generating Station	7,771	1,446	(399)
Kelsey Improvements & Upgrades	302	112	111
Pointe du Bois Spillway Replacement	398	80	83
Kettle Improvements & Upgrades	166	90	70
Wuskwatim Generating Station	1,275	-	55
Pointe du Bois Safety Upgrades	50	50	50
System Refurbishment and Other Projects	NA	NA	328
Reduction to Target Adjustment	NA	NA	333
			$ 1,555

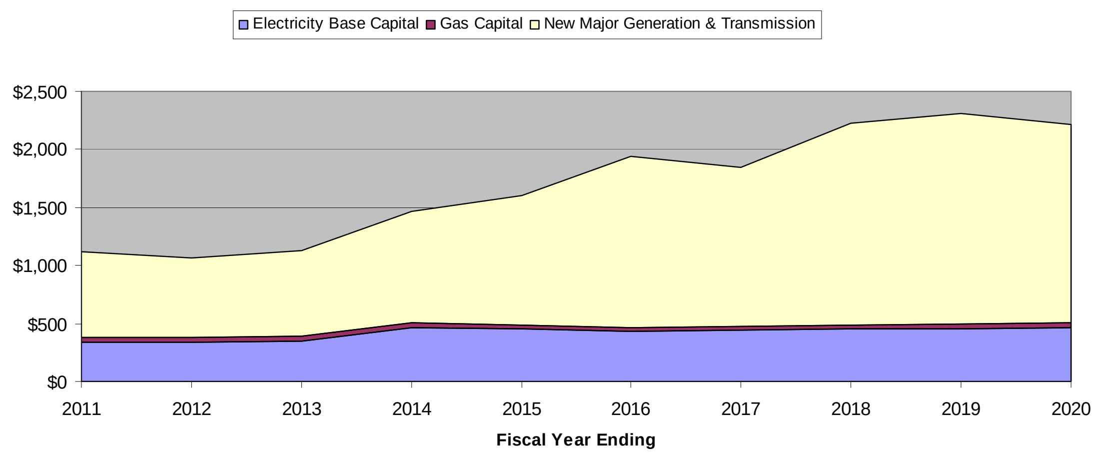
Projected Consolidated Capital Expenditures

millions of dollars



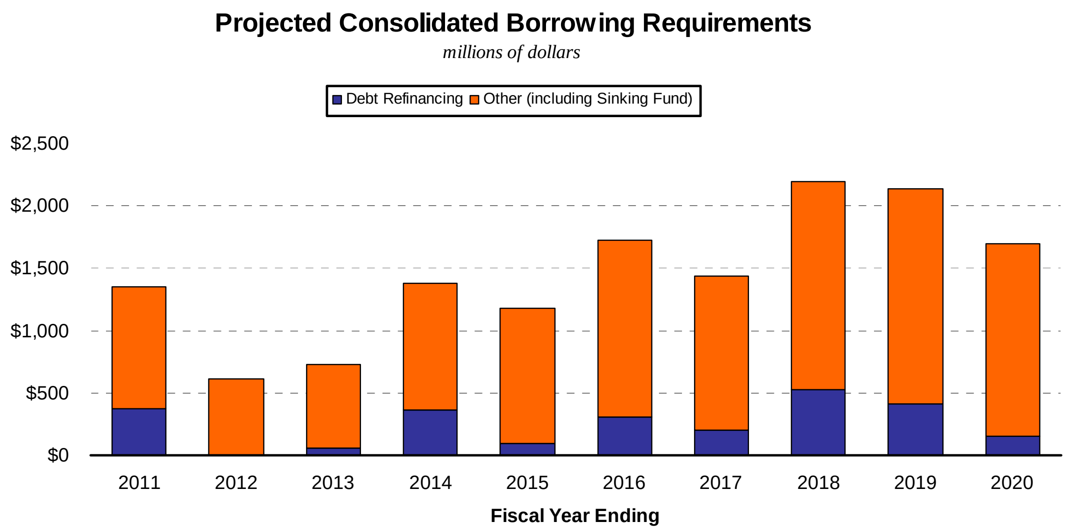
Projected Capital Expenditures
Major Categories

millions of dollars



6.0 BORROWING REQUIREMENTS

Manitoba Hydro's forecast consolidated 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. Manitoba Hydro's target range is to hold 15% to 25% of debt in floating rate instruments in order to minimize debt costs without undue interest rate exposure. Currently, about 20% of Manitoba Hydro's debt is in floating rate instruments. It is assumed that Manitoba Hydro will maintain floating rate debt at current levels throughout the forecast period.

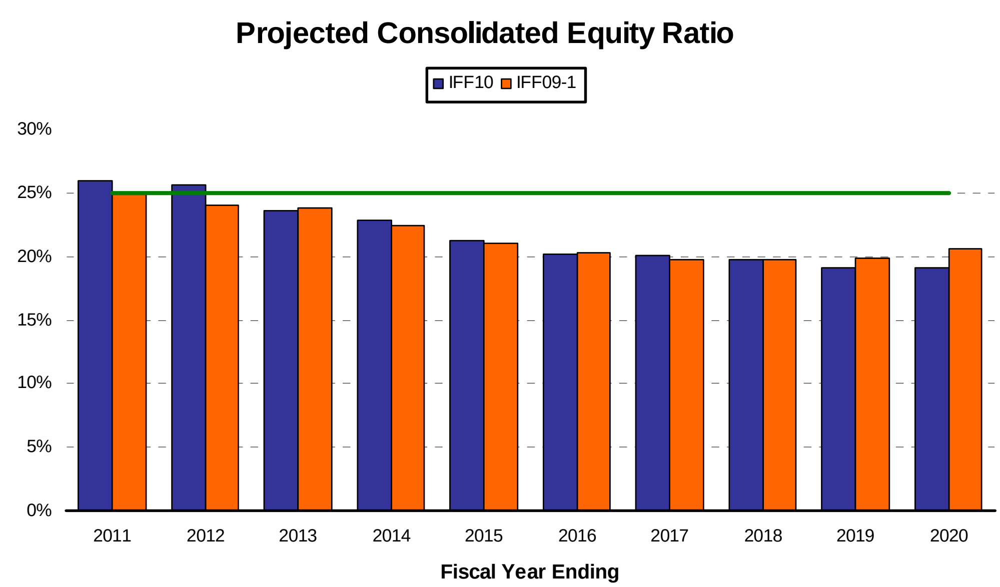
7.0 FINANCIAL TARGETS

Debt/Equity Ratio	Maintain a minimum debt/equity ratio of 75:25
Interest Coverage	Maintain an annual gross interest coverage ratio of greater than 1.20
Capital Coverage	Maintain a capital coverage ratio of greater than 1.20 (excepting new major generation and transmission)

Note: Financial Targets may not be maintained during years of major investment in the generation and transmission system.

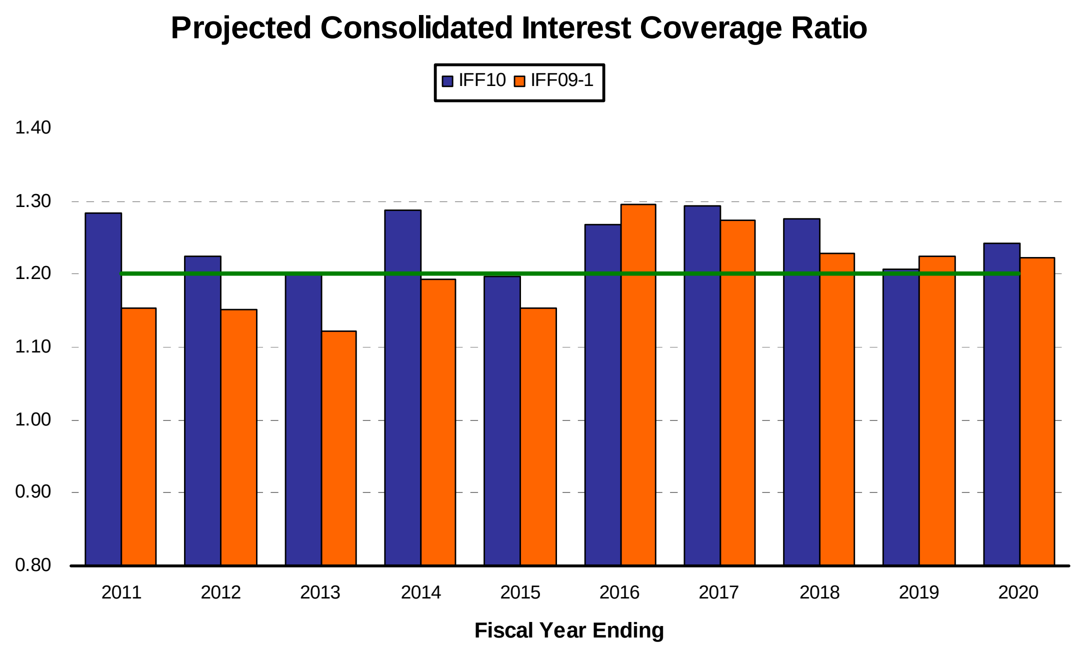
7.1 EQUITY RATIO

The equity ratio indicates the portion of Manitoba Hydro's capital structure that has been financed internally and not through debt financing. Primarily due to major investments in the generation and transmission system over the next decade ("the decade of investment") and lower net export revenues compared to the previous forecast IFF09, this ratio is projected to regress to 81:19 by 2019/20. However, the equity ratio is projected to recover strongly in the subsequent decade ("the decade of returns") during which the benefits of major power sales are projected to be realized (see section 8.0).



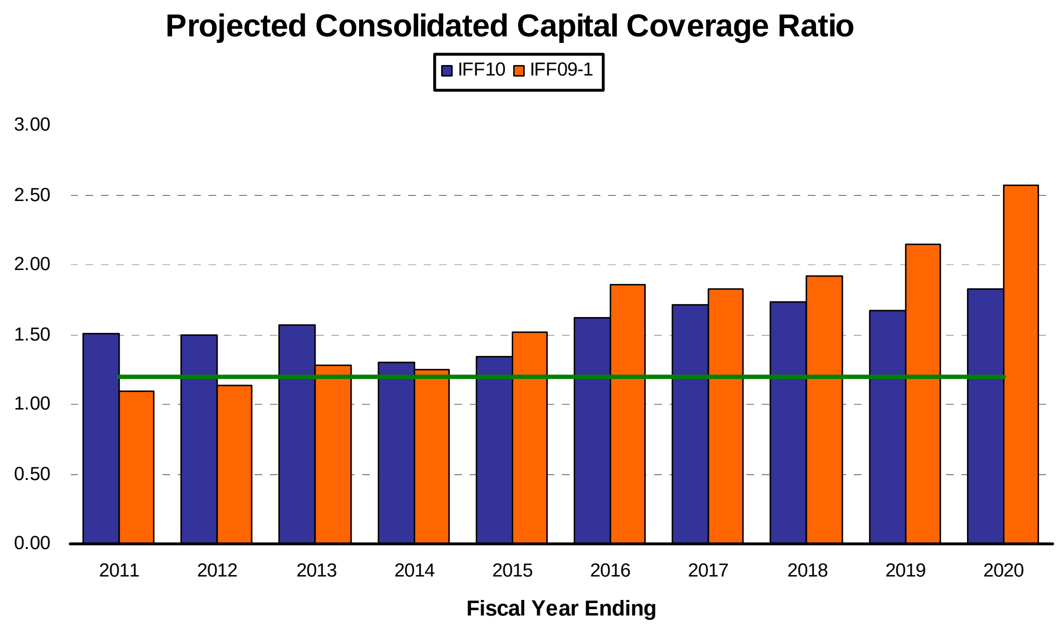
7.2 INTEREST COVERAGE RATIO

The interest coverage ratio provides an indication of the ability of the Corporation to meet interest payment obligations without the need for further borrowing. The effects of current favourable water flow conditions can be seen in the level of interest coverage projected for 2010/11 with the carry-over effects into 2011/12. Lower projected net export revenues and the deferral of Keeyask result in the interest coverage ratio weakening at points through the 10-year forecast but remains at or above the target interest coverage of 1.20.



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 and related transmission. Projected net income levels are sufficient to enable this target to be met throughout the 10-year forecast period.

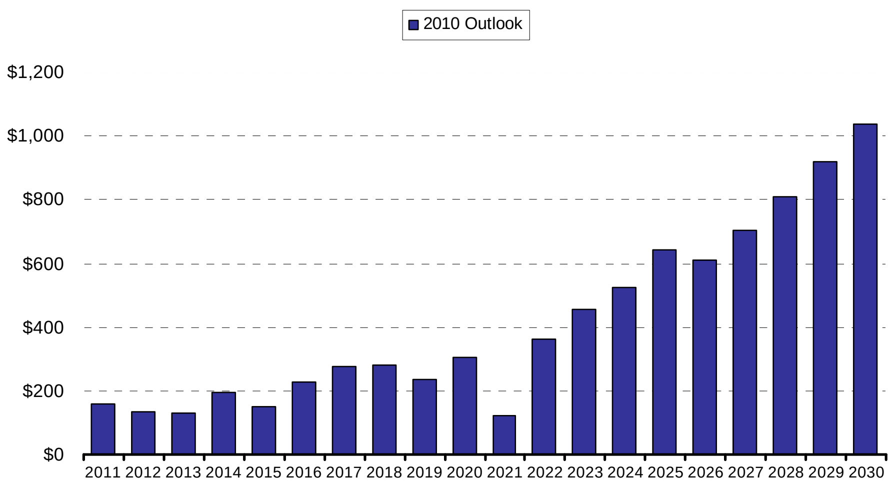


8.0 20 YEAR OUTLOOK

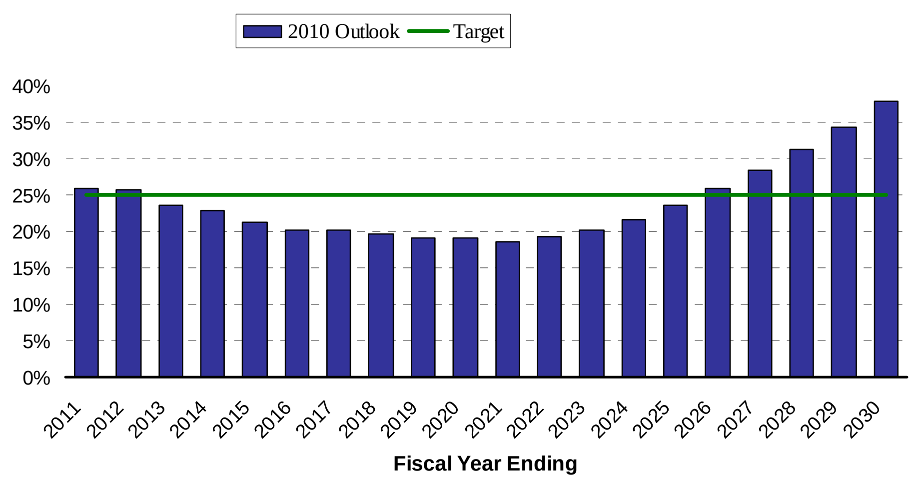
Manitoba Hydro produces a 20 Year Outlook as an extension to the 10 year Integrated Financial Forecast. While the 20 Year Outlook will be provided as a stand-alone document, excerpts show that following a decade of investment in new generation and transmission, the financial returns in the next decade are significant. This is depicted in the following graphs which, for illustrative purposes, incorporate average annual rate increases in the periods following IFF10 which are similar to the projected rates of inflation (i.e. 2.0% per year).

Projected Consolidated Net Income

millions of dollars



Projected Consolidated Equity Ratio



9.0 RISK ANALYSIS

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.

The table below shows the change in retained earnings assuming no change to rate increases and equal annual rate increases/decreases relative to IFF10 necessary to offset the risks outlined above.

	2012/13	2016/17	2020/21	
	Incremental Increase/(Decrease) in Retained Earnings (in millions of dollars)			Incremental Annual Electric Rate Increase/(Decrease) *
+ 1% Interest Rates	3	(69)	(432)	0.45%
- 1% Interest Rates	(1)	76	430	-0.49%
US $ up $0.10	27	57	151	-0.17%
US $ down $0.10	(26)	(47)	(125)	0.14%
Low Export Prices	(42)	(256)	(587)	0.64%
High Export Prices	61	549	1,491	-1.72%
5 Year Drought (starting in 2012/13)	N/A	(2,094)	N/A	2.76%
Capital Expenditures +$100M per year	(12)	(171)	(549)	0.56%
Medium High Electric Load Forecast	(3)	(37)	(268)	0.28%

***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 2020/21 as in the base MH10.

Interest rates and foreign exchange

For the foreign exchange rate sensitivities and +/- 1% interest rate sensitivities, rates were adjusted beginning in fiscal year 2011/12. In the +/- 1% interest rate case, the changes in rates were applied to all new long and short-term debt issues, new sinking fund instruments and all floating rate debt. For all other sensitivities, changes from MH10 begin in fiscal year 2012/13.

Export prices

Manitoba Hydro has developed an ‘Expected’ forecast of power prices for export which is used in the MH10 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 2012/13 and 2020/21, net revenue would decline by more than $0.5 billion under the Low price forecast and increase by $1.3 billion under the High price forecast compared to the Expected price forecast.

Increase in Capital Expenditures

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

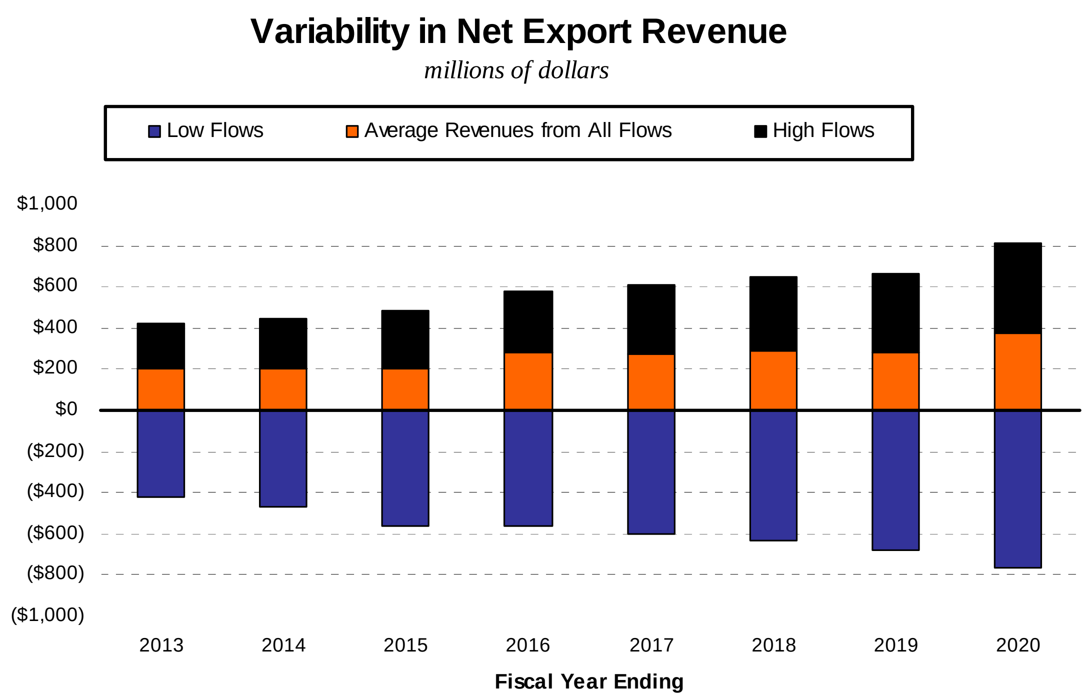
Manitoba load growth

The base load forecast used in MH10 represents the most likely future electricity requirements within the Province of Manitoba. The medium-high load forecast has been evaluated to determine the financial impact on Manitoba Hydro of higher growth in the Province. 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.

Water conditions

On average, there is a high likelihood of a significant drought occurring about once every ten years and this probability is incorporated in the revenue forecast. 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 2012/13 and extending to 2016/17. In order to calculate the impacts of the drought on export revenues and thermal generation and import costs, a price forecast based on expected market conditions was assumed. Over the five year drought period, net export revenue would be reduced more than $2 billion (including financing costs) compared to MH10. If a drought of this magnitude were to coincide with a period of high prices for thermal generation and import purchases the impact would be greater.

The graph below shows the variability in net export revenues due to fluctuations in water flows.



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 any 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

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10.0 PROJECTED CONSOLIDATED FINANCIAL STATEMENTS (IFF10)

CONSOLIDATED PROJECTED OPERATING STATEMENT (IFF10)
(In Millions of Dollars)

For the year ended March 31	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
REVENUES										
General Consumers	1,610	1,719	1,792	1,854	1,918	1,988	2,064	2,133	2,210	2,294
Extraprovincial	444	461	499	510	529	611	621	646	654	804
	2,054	2,180	2,291	2,364	2,447	2,599	2,685	2,779	2,864	3,098
Cost of Gas Sold	273	311	320	310	309	309	308	306	304	303
	1,781	1,869	1,971	2,054	2,138	2,290	2,378	2,472	2,559	2,795
Other	28	31	33	33	34	34	35	36	36	37
	1,809	1,900	2,004	2,087	2,171	2,325	2,413	2,508	2,596	2,832
EXPENSES										
Operating and Administrative	476	482	495	505	515	526	536	559	570	589
Finance Expense	430	449	512	496	563	587	582	608	678	746
Depreciation and Amortization	403	435	464	468	495	517	524	543	573	589
Water Rentals and Assessments	121	115	111	112	112	113	113	113	113	113
Fuel and Power Purchased	121	187	190	203	216	225	239	251	264	316
Capital and Other Taxes	100	102	106	112	118	126	134	143	152	162
	1,650	1,771	1,879	1,896	2,020	2,093	2,128	2,217	2,349	2,513
Non-controlling Interest	-	4	6	4	0	(4)	(7)	(9)	(12)	(15)
Net Income	158	134	130	195	152	228	278	282	234	303
Additional General Consumers Revenue										
General electricity rate increases		2.90%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%
General gas rate increases		0.00%	1.50%	1.00%	1.00%	1.00%	1.00%	0.00%	1.00%	1.00%
Financial Ratios										
Equity	26%	26%	24%	23%	21%	20%	20%	20%	19%	19%
Interest Coverage	1.28	1.22	1.20	1.29	1.20	1.27	1.29	1.27	1.21	1.24
Capital Coverage	1.50	1.50	1.57	1.29	1.34	1.62	1.71	1.73	1.67	1.83

CONSOLIDATED PROJECTED BALANCE SHEET (IFF10)
(In Millions of Dollars)

For the year ended March 31	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
ASSETS										
Plant in Service	13,226	15,218	15,744	16,319	17,485	18,051	18,632	21,056	21,893	25,741
Accumulated Depreciation	(4,971)	(5,350)	(5,762)	(6,184)	(6,588)	(7,033)	(7,509)	(8,012)	(8,547)	(9,100)
Net Plant in Service	8,255	9,868	9,982	10,135	10,898	11,018	11,123	13,044	13,346	16,640
Construction in Progress	2,624	1,636	2,216	3,091	3,457	4,792	6,042	5,825	7,283	5,522
Current and Other Assets	1,414	1,506	1,300	1,016	1,156	1,360	1,560	1,836	1,606	1,863
Goodwill and Intangible Assets	237	231	214	199	186	178	169	162	174	181
Regulated Assets	292	312	325	333	335	330	315	296	271	250
	12,822	13,552	14,038	14,774	16,031	17,679	19,208	21,163	22,682	24,455
LIABILITIES AND EQUITY										
Long-Term Debt	8,524	8,944	8,966	10,296	11,311	12,986	13,858	15,204	17,090	14,690
Current and Other Liabilities	1,339	1,516	2,111	1,378	1,610	1,448	1,842	2,189	1,597	5,476
Contributions in Aid of Construction	295	294	288	282	278	275	272	270	267	265
Retained Earnings	2,398	2,531	2,658	2,853	3,005	3,233	3,511	3,793	4,027	4,331
Accumulated Other Comprehensive Income	266	266	14	(35)	(173)	(264)	(275)	(293)	(300)	(307)
	12,822	13,552	14,038	14,774	16,031	17,679	19,208	21,163	22,682	24,455
Equity Ratio	26%	26%	24%	23%	21%	20%	20%	20%	19%	19%

CONSOLIDATED PROJECTED CASH FLOW STATEMENT (IFF10)
(In Millions of Dollars)

For the year ended March 31	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
OPERATING ACTIVITIES										
Cash Receipts from Customers	2,146	2,282	2,394	2,467	2,545	2,698	2,784	2,878	2,963	3,198
Cash Paid to Suppliers and Employees	(1,187)	(1,288)	(1,301)	(1,328)	(1,352)	(1,376)	(1,407)	(1,451)	(1,482)	(1,561)
Interest Paid	(420)	(453)	(507)	(512)	(553)	(590)	(599)	(636)	(707)	(757)
Interest Received	25	29	30	26	16	26	39	49	53	47
	564	570	616	653	656	758	817	841	827	927
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	1,000	600	800	1,400	1,200	1,800	1,400	2,200	2,200	1,800
Sinking Fund Withdrawals	651	25	128	463	-	8	-	-	444	167
Retirement of Long-Term Debt	(1,025)	(25)	(182)	(829)	(100)	(312)	(201)	(530)	(857)	(317)
Other	(229)	18	(12)	(7)	(0)	(3)	(2)	(1)	(12)	(3)
	398	618	735	1,027	1,100	1,494	1,197	1,669	1,776	1,647
INVESTING ACTIVITIES										
Property, Plant and Equipment, net of contributions	(1,174)	(1,087)	(1,148)	(1,476)	(1,606)	(1,944)	(1,850)	(2,235)	(2,315)	(2,218)
Sinking Fund Payment	(119)	(99)	(117)	(167)	(111)	(199)	(157)	(239)	(198)	(226)
Other	(21)	(16)	(17)	(16)	(17)	(36)	(46)	(27)	(27)	(27)
	(1,314)	(1,202)	(1,281)	(1,659)	(1,734)	(2,179)	(2,053)	(2,501)	(2,540)	(2,472)
Net Increase (Decrease) in Cash	(352)	(14)	69	21	22	73	(39)	8	63	102
Cash at Beginning of Year	158	(193)	(207)	(139)	(117)	(95)	(23)	(62)	(53)	10
Cash at End of Year	(193)	(207)	(139)	(117)	(95)	(23)	(62)	(53)	10	112

11.0 CAPITAL EXPENDITURE FORECAST (CEF10)

CAPITAL EXPENDITURE FORECAST (CEF10)
(in millions of dollars)

	Total Project Cost	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	10 Year Total
ELECTRIC												
Major New Generation & Transmission												
Wuskwatim - Generation	1,274.6	300.8	130.3	16.2	-	-	-	-	-	-	-	447.2
Wuskwatim - Transmission	291.2	35.7	21.2	-	-	-	-	-	-	-	-	56.9
Herblet Lake - The Pas 230 kV Transmission	74.9	22.2	6.0	0.0	-	-	-	-	-	-	-	28.3
Keeyask - Generation	5,636.9	71.2	152.5	179.2	312.3	379.5	683.0	749.1	1,080.5	816.6	640.1	5,064.0
Conawapa - Generation	7,770.8	42.4	104.4	105.2	83.3	166.4	288.6	333.4	325.1	623.4	1,038.0	3,110.1
Kelsey Improvements & Upgrades	301.7	42.7	34.7	28.5	12.5	-	-	-	-	-	-	118.6
Kettle Improvements & Upgrades	165.7	17.5	18.7	21.6	22.2	15.4	7.3	7.5	7.6	7.7	7.9	133.6
Pointe du Bois Spillway Replacement	398.2	18.6	24.4	92.7	103.6	89.2	31.5	0.5	0.0	0.0	0.0	360.5
Pointe du Bois - Transmission	86.0	20.5	15.6	25.0	13.1	3.1	-	-	-	-	-	77.3
Bipole III - Licensing & Properties	123.5	9.1	18.9	9.6	9.3	9.8	11.1	5.9	11.2	0.2	-	85.1
Bipole III - Transmission Line	958.4	2.8	5.4	38.2	87.9	181.9	313.1	133.0	192.2	-	-	954.6
Keewatinoow Converter Station	466.3	6.3	11.8	60.5	78.3	56.0	81.1	43.5	8.2	118.8	-	464.6
Keewatinoow AC Collector System	80.9	1.9	7.4	32.5	35.2	0.9	1.3	0.7	0.9	-	-	80.8
Riel Converter Station	618.7	36.7	31.7	58.7	135.1	128.1	14.4	5.0	1.7	196.2	-	607.7
Riel 230/500 kV Station	267.6	70.2	66.8	29.4	28.9	41.3	-	-	-	-	-	236.5
Ontario 100 MW Firm Import Upgrades	4.8	-	0.6	2.2	1.9	-	-	-	-	-	-	4.8
Dorsey - US Border New 500 kV Transmission Line	204.8	0.0	0.1	0.9	1.9	2.4	11.7	64.5	93.5	28.9	-	204.0
St. Joseph Wind Transmission	6.5	5.5	0.0	-	-	-	-	-	-	-	-	5.6
Demand Side Management	NA	36.9	38.0	39.1	38.6	36.2	29.5	25.0	23.0	21.9	20.4	308.6
Waterways Management Program	NA	5.5	-	-	-	-	-	-	-	-	-	5.5
		746.6	688.6	739.7	964.3	1,110.2	1,472.7	1,368.0	1,743.9	1,813.8	1,706.4	12,354.1

CAPITAL EXPENDITURE FORECAST (CEF10)
(in millions of dollars)

	Total Project Cost	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	10 Year Total
Power Supply												
HVDC Converter Transformer Bushing Replacement	5.9	0.4	0.7	1.1	-	-	-	-	-	-	-	2.2
HVDC Auxiliary Power Supply Upgrades	5.3	0.9	0.2	-	-	-	-	-	-	-	-	1.2
Dorsey Synchronous Condenser Refurbishment	32.3	2.5	4.5	4.4	1.1	-	-	-	-	-	-	12.5
HVDC System Transformer & Reactor Fire Protection & Prevention	10.4	1.0	0.6	0.2	-	-	-	-	-	-	-	1.8
HVDC AC Filter PCB Capacitor Replacement	29.8	1.2	-	-	-	-	-	-	-	-	-	1.2
HVDC Transformer Replacement Program	105.7	0.3	1.1	4.9	8.1	-	-	-	-	-	-	14.5
Dorsey 230 kV Relay Building Upgrade	82.2	4.4	3.7	3.4	17.5	35.4	12.3	3.2	-	-	-	79.8
HVDC Stations Ground Grid Refurbishment	4.3	0.5	0.4	0.4	0.4	0.3	0.1	-	-	-	-	2.2
HVDC Circuit Breaker Operating Mechanism Replacement	15.9	1.9	2.7	1.1	0.4	0.1	0.1	0.1	0.1	0.1	-	6.6
HVDC Bipole 1 Pole Differential Protection	3.3	-	-	1.1	2.2	-	-	-	-	-	-	3.3
HVDC Bipole 1 By-Pass Vacuum Switch Removal	20.4	0.5	2.5	3.9	11.0	2.1	-	-	-	-	-	19.9
HVDC Bipole 2 Refrigerant Condenser Replacement	11.0	-	-	2.9	2.4	5.7	-	-	-	-	-	11.0
HVDC Bipole 1 & 2 Smoothing Reactor Replacement	39.3	14.3	12.8	1.9	9.2	-	-	-	-	-	-	38.2
HVDC Bipole 1 P1 & P2 Battery Bank Separation	3.2	0.0	0.9	2.2	-	-	-	-	-	-	-	3.2
HVDC Bipole 1 DCCT Transductor Replacement	11.7	0.0	0.5	1.6	1.1	3.0	3.1	2.3	-	-	-	11.7
HVDC Bipole 1 & 2 DC Converter Transformer Bushing Replacements	8.7	-	0.6	1.0	1.7	5.4	0.0	-	-	-	-	8.7
HVDC Bipole 2 Valve Hall Wall Bushing Replacements	19.2	0.5	0.1	0.2	3.4	4.4	4.1	4.8	1.4	-	-	18.9
HVDC Bipole 1 CQ Disconnect Replacement	5.2	-	0.3	0.9	1.5	1.1	1.1	0.3	-	-	-	5.2
HVDC Bipole 2 Refurbish Thyristor Module Cooling Components	4.7	1.4	1.3	-	-	-	-	-	-	-	-	2.7
HVDC Transformer Marshalling Kiosk Replacement	6.8	0.6	1.8	2.0	1.2	0.7	-	-	-	-	-	6.3
HVDC Gapped Arrestor Replacement	16.3	0.1	3.8	3.4	4.0	3.5	1.3	0.2	-	-	-	16.3
Pine Falls Rehabilitation	56.2	2.5	5.8	15.8	1.2	4.6	6.8	9.0	-	-	-	45.8
Jenpeg Unit Overhauls	128.1	-	-	-	-	-	2.3	2.5	18.5	24.3	24.9	72.5
Power Supply Dam Safety Upgrades	34.0	4.3	-	-	-	-	-	-	-	-	-	4.3
Winnipeg River Riverbank Protection Program	19.7	1.2	1.2	1.3	1.3	1.3	1.3	1.4	-	-	-	9.1
Power Supply Hydraulic Controls	20.5	3.7	1.5	0.5	1.3	-	-	-	2.1	2.6	0.9	12.6
Slave Falls Rehabilitation	223.0	19.8	7.3	1.7	3.7	32.4	40.8	45.6	38.8	9.2	-	199.4
Great Falls Unit 4 Overhaul	19.7	4.5	9.5	-	-	-	-	-	-	-	-	14.0
Great Falls Unit 5 Discharge Ring Replacement and Major Overhaul	24.8	-	-	-	-	2.3	17.5	5.0	-	-	-	24.8
Generation South Transformer Refurbish & Spares	29.8	0.4	4.8	11.3	12.1	0.5	0.3	0.3	-	-	-	29.7
Water Licenses & Renewals	40.8	5.3	6.0	6.2	6.8	6.6	0.7	-	-	-	-	31.5
Generation South PCB Regulation Compliance	4.7	0.6	0.5	0.4	0.4	0.2	2.4	-	-	-	-	4.5
Kettle Transformer Replacement Program	35.6	8.7	7.0	7.2	8.0	3.9	-	-	-	-	-	34.8
Generation South Breaker Replacement Program	11.1	2.5	3.0	1.4	3.4	-	-	-	-	-	-	10.3
Seven Sisters Upgrades	9.5	2.8	2.0	1.5	1.2	-	-	-	-	-	-	7.6
Generation South Excitation Program	18.3	0.1	0.3	2.1	2.4	0.6	1.5	2.9	1.7	6.8	-	18.3
Brandon Unit 5 License Review	18.7	0.2	0.1	1.6	2.7	9.2	-	-	-	-	-	13.8
Selkirk Enhancements	14.2	1.5	0.4	-	-	-	-	-	-	-	-	1.9
Laurie River/CRD Communications & Annunciation Upgrades	4.8	0.9	3.1	0.7	-	-	-	-	-	-	-	4.6
Notigi Marine Vessel Replacement & Infrastructure Improvements	4.6	0.9	3.0	0.6	-	-	-	-	-	-	-	4.5
Pointe du Bois Safety Upgrades	50.0	0.5	1.6	5.5	11.2	16.0	11.7	3.5	-	-	-	50.0
Fire Protection Projects - HVDC	5.2	0.6	0.4	0.3	1.2	1.0	-	-	-	-	-	3.5
Halon Replacement Project	36.4	4.6	5.5	6.8	2.7	-	-	-	-	-	-	19.7

CAPITAL EXPENDITURE FORECAST (CEF10)
(in millions of dollars)

	Total Project Cost	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	10 Year Total
Power Supply - continued												
Oil Containment - Power Supply	19.1	0.5	0.6	0.5	0.7	0.4	0.5	0.5	-	-	-	3.8
Grand Rapids Townsite House Renovations	5.2	0.4	0.9	1.3	1.6	1.0	-	-	-	-	-	5.2
Grand Rapids Fish Hatchery	2.2	1.1	1.1	-	-	-	-	-	-	-	-	2.2
Generation Townsite Infrastructure	52.1	6.1	8.0	1.8	-	-	-	-	-	-	-	15.8
Site Remediation of Contaminated Corporate Facilities	34.7	1.0	1.7	1.0	1.6	-	-	-	-	-	-	5.3
High Voltage Test Facility	26.9	11.9	5.6	-	-	-	-	-	-	-	-	17.5
Security Installations / Upgrades	43.2	8.6	11.4	8.3	3.2	1.3	1.1	0.7	-	-	-	34.5
Sewer & Domestic Water System Install and Upgrade	26.9	7.1	4.9	3.2	(0.1)	-	-	-	-	-	-	15.0
Power Supply Domestic	NA	19.3	19.7	20.1	20.5	20.9	21.4	21.8	22.2	22.7	23.1	211.8
		152.1	155.6	137.6	152.2	163.9	130.5	104.1	84.8	65.6	48.9	1,195.3
Transmission												
Winnipeg - Brandon Transmission System Improvements	40.0	1.4	2.0	2.5	15.0	15.0	-	-	-	-	-	35.8
Transcona East 230 - 66 kV Station	33.1	10.4	17.7	3.6	0.0	-	-	-	-	-	-	31.7
Neepawa 230 - 66 kV Station	30.0	5.3	12.0	5.1	5.7	0.7	-	-	-	-	-	28.8
Pine Falls - Bloodvein 115 kV Transmission	33.1	0.3	0.9	4.4	20.7	6.8	-	-	-	-	-	33.1
Transmission Line Re-Rating	24.1	1.1	1.3	-	-	-	-	-	-	-	-	2.3
St Vital-Steinbach 230 kV Transmission	32.2	-	-	-	-	-	0.9	0.9	2.6	6.1	9.8	20.3
Rosser Station 230 - 115 kV Bank 3 Replacement	7.4	0.6	-	-	-	-	-	-	-	-	-	0.6
Rosser - Inkster 115 kV Transmission	5.1	2.6	-	-	-	-	-	-	-	-	-	2.6
Transcona Station 66 kV Breaker Replacement	6.0	-	0.4	2.9	1.5	1.1	-	-	-	-	-	6.0
Transcona & Ridgeway Stations 66 kV Bus Upgrades	1.6	-	-	-	-	-	-	-	-	-	-	(0.0)
Dorsey 500 kV R502 Breaker Replacement	2.6	0.3	-	-	-	-	-	-	-	-	-	0.3
13.2kV Shunt Reactor Replacements	33.0	-	4.0	4.1	4.2	4.3	4.4	4.5	4.6	2.9	-	33.0
Canexus Load Addition	(0.2)	(0.8)	2.0	0.0	-	-	-	-	-	-	-	1.3
Birtle South-Rossburn 66 kV Line	4.9	-	-	-	0.1	0.3	4.5	-	-	-	-	4.9
Stanley Station 230-66 kV Transformer Addition	21.1	-	-	1.7	8.1	7.5	3.8	-	-	-	-	21.1
Stanley Station 230-66 kV Hot Standby	6.2	1.3	-	-	-	-	-	-	-	-	-	1.3
Enbridge Pipelines Clipper Project	0.9	5.2	0.3	-	-	-	-	-	-	-	-	5.5
TCPL Keystone Project	8.0	2.3	1.9	1.6	-	-	-	-	-	-	-	5.8
Ashern Station Bank Addition	10.6	0.1	0.4	3.5	5.6	1.0	-	-	-	-	-	10.6
Ashern Station Reactor Replacement	2.7	-	-	2.7	-	-	-	-	-	-	-	2.7
Tadoule Lake DGS Tank Farm Upgrade	1.1	5.1	(4.3)	-	-	-	-	-	-	-	-	0.7
Interlake Digital Microwave Replacement	19.7	0.7	-	-	-	-	-	-	-	-	-	0.7
Pilot Wire Replacement	8.3	0.5	-	-	-	-	-	-	-	-	-	0.5
Transmission Line Protection & Teleprotection Replacement	21.1	0.8	2.7	3.8	4.3	3.4	2.6	0.1	-	-	-	17.7
Winnipeg Central Protection Wireline Replacement	10.5	1.5	0.4	-	-	-	-	-	-	-	-	1.9
Mobile Radio System Modernization	30.7	0.4	2.5	6.1	2.9	11.7	7.1	-	-	-	-	30.6
Cyber Security Systems	10.1	1.3	-	-	-	-	-	-	-	-	-	1.3
Site Remediation of Diesel Generating Stations	13.3	3.8	1.9	0.3	-	-	-	-	-	-	-	6.0
Oil Containment - Transmission	7.4	0.8	0.2	-	-	-	-	-	-	-	-	1.1
Station Battery Bank Capacity & System Reliability Increase	46.5	5.0	5.7	4.8	5.8	4.5	4.4	-	-	-	-	30.2
Waverley Service Centre Oil Tank Farm Replacement	3.0	1.1	0.5	0.4	0.7	-	-	-	-	-	-	2.7
Transmission Domestic	NA	30.0	30.6	31.2	31.8	32.4	33.1	33.7	34.4	35.1	35.8	328.1
		81.0	83.1	78.7	106.5	88.6	60.7	39.3	41.6	44.1	45.6	669.1

CAPITAL EXPENDITURE FORECAST (CEF10)
(in millions of dollars)

	Total Project Cost	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	10 Year Total
Customer Service & Distribution												
Winnipeg Distribution Infrastructure Requirements	24.5	2.2	2.3	2.3	2.3	-	-	-	-	-	-	9.1
Defective RINJ Cable Replacements	8.7	1.0	2.1	-	-	-	-	-	-	-	-	3.1
Rover 4 kV Station Salvage & Feeder Conversion	12.7	0.1	3.1	4.3	-	-	-	-	-	-	-	7.5
Martin New 66-4 kV Station	28.2	1.0	5.1	6.9	9.0	1.8	-	-	-	-	-	23.7
Frobisher Station Upgrade	14.4	1.6	-	-	-	-	-	-	-	-	-	1.6
Burrows New 66 -12 kV Station	28.6	4.2	12.2	6.4	-	-	-	-	-	-	-	22.8
Winnipeg Central Oil Switch Project	7.1	0.2	-	-	-	-	-	-	-	-	-	0.2
Teulon East 66-12 kV Station	4.6	4.5	0.1	-	-	-	-	-	-	-	-	4.6
William New 66 -12 kV Station	10.3	0.3	0.4	9.3	-	-	-	-	-	-	-	10.0
Waverley West Sub Division Supply	6.5	3.0	-	-	-	-	-	-	-	-	-	3.0
St. James New Station & 24 kV Conversion	65.9	0.1	2.6	5.9	6.8	10.4	21.2	18.8	-	-	-	65.8
Shoal Lake New DSC & Town Conversion	3.6	0.2	-	-	-	-	-	-	-	-	-	0.2
York Station Bank & Switchgear Addition	4.0	2.7	-	-	-	-	-	-	-	-	-	2.7
Cromer North Station & Reston RE12-4 25 kV Conversion	4.3	0.3	1.3	-	-	-	-	-	-	-	-	1.6
Brandon Crocus Plains 115 - 25 kV Bank Addition	6.3	-	-	6.2	-	-	-	-	-	-	-	6.2
Neepawa North Feeder NN12-2 & Line 57 Rebuild	1.9	1.9	-	-	-	-	-	-	-	-	-	1.9
Line 27 66 kV Extension and Arborg North DSC	6.0	0.4	5.4	-	-	-	-	-	-	-	-	5.7
Health Sciences Centre Service Consolidation & Distribution Upgrade	15.8	3.6	3.6	3.1	2.2	3.2	0.1	-	-	-	-	15.8
AECL Switchgear Replacement	2.4	1.1	1.1	-	-	-	-	-	-	-	-	2.1
Waverley South DSC Installation	3.9	3.8	-	-	-	-	-	-	-	-	-	3.8
Niverville Station 66-12 kV Bank Replacements	2.6	0.6	-	-	-	-	-	-	-	-	-	0.6
Customer Service & Distribution Domestic	NA	117.5	119.9	122.3	124.7	127.2	129.8	132.4	135.0	137.7	140.5	1,286.9
		150.2	159.0	166.8	145.1	142.5	151.1	151.2	135.0	137.7	140.5	1,479.0
Customer Care & Marketing												
Advanced Metering Infrastructure	30.9	-	4.0	5.3	5.4	5.6	4.3	4.2	-	-	-	28.8
Customer Care & Marketing Domestic	NA	2.6	2.6	2.7	2.7	2.8	2.8	2.9	2.9	3.0	3.1	28.1
		2.6	6.6	8.0	8.1	8.4	7.2	7.1	2.9	3.0	3.1	56.9

CAPITAL EXPENDITURE FORECAST (CEF10)
(in millions of dollars)

	Total Project Cost	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	10 Year Total
Finance & Administration												
Corporate Buildings Program	NA	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	80.0
Workforce Management	11.3	0.8	-	-	-	-	-	-	-	-	-	0.8
Fleet Acqusitions	NA	13.5	13.8	14.1	14.3	14.6	14.9	15.2	15.5	15.8	16.2	148.0
Finance & Administration Domestic	NA	24.4	24.9	25.4	25.9	26.4	27.0	27.5	28.1	28.6	29.2	267.5
		46.7	46.7	47.5	48.3	49.1	49.9	50.7	51.6	52.5	53.3	496.2
Capital Increase Provision		-	-	-	-	(0.0)	31.1	87.9	133.7	155.4	177.2	585.2
ELECTRIC CAPITAL SUBTOTAL		**1,179.3**	**1,139.6**	**1,178.2**	**1,424.5**	**1,562.7**	**1,903.0**	**1,808.2**	**2,193.5**	**2,272.1**	**2,174.9**	**16,836.0**
GAS												
Customer Service & Distribution												
Ile Des Chenes NG Transmission Network Upgrade	1.2	0.8	0.4	-	-	-	-	-	-	-	-	1.2
Centerport NPS 16 Natural Gas Transmission Main	1.7	1.7	-	-	-	-	-	-	-	-	-	1.7
Gas SCADA Replacement	4.6	1.8	2.6	-	-	-	-	-	-	-	-	4.4
Customer Service & Distribution Domestic	NA	21.2	21.7	22.1	22.5	23.0	23.4	23.9	24.4	24.9	25.4	232.5
		25.6	24.6	22.1	22.5	23.0	23.4	23.9	24.4	24.9	25.4	239.8
Customer Care & Marketing												
Advanced Metering Infrastructure	15.0	-	1.0	5.4	8.4	-	-	-	-	-	-	14.7
Demand Side Management	NA	11.2	12.0	12.4	10.4	10.4	10.0	9.4	7.2	5.6	5.1	93.7
Customer Care & Marketing Domestic	NA	2.8	2.9	2.9	3.0	3.0	3.1	3.2	3.2	3.3	3.4	30.7
		14.0	15.9	20.7	21.8	13.4	13.1	12.5	10.5	8.9	8.5	139.2
Capital Increase Provision		-	-	-	-	-	-	-	2.3	4.9	5.0	12.1
GAS CAPITAL SUBTOTAL		**39.6**	**40.5**	**42.8**	**44.3**	**36.4**	**36.6**	**36.4**	**37.1**	**38.7**	**38.8**	**391.1**
CONSOLIDATED CAPITAL		**1,218.9**	**1,180.1**	**1,220.9**	**1,468.8**	**1,599.1**	**1,939.6**	**1,844.7**	**2,230.6**	**2,310.7**	**2,213.7**	**17,227.1**
TARGET ADJUSTMENT		(97.0)	(111.0)	(88.0)	-	-	-	-	-	-	-	(296.0)
CEF10 TOTAL		**1,121.9**	**1,069.1**	**1,132.9**	**1,468.8**	**1,599.1**	**1,939.6**	**1,844.7**	**2,230.6**	**2,310.7**	**2,213.7**	**16,931.1**

12.0 ELECTRIC OPERATIONS FINANCIAL FORECAST (MH10)

ELECTRIC OPERATIONS (MH10)
PROJECTED OPERATING STATEMENT
(In Millions of Dollars)

For the year ended March 31	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
REVENUES										
General Consumers										
at approved rates	1,194	1,223	1,235	1,254	1,265	1,279	1,296	1,307	1,320	1,336
additional *	-	42	87	135	186	239	295	354	416	482
Extraprovincial	444	461	499	510	529	611	621	646	654	804
Other	7	7	8	8	8	8	8	8	8	8
	1,645	1,732	1,829	1,907	1,988	2,137	2,220	2,315	2,398	2,630
EXPENSES										
Operating and Administrative	398	402	414	422	430	439	448	469	478	495
Finance Expense	393	411	473	455	521	544	540	565	635	702
Depreciation and Amortization	374	405	432	433	458	480	485	504	531	547
Water Rentals and Assessments	121	115	111	112	112	113	113	113	113	113
Fuel and Power Purchased	121	187	190	203	216	225	239	251	264	316
Capital and Other Taxes	81	82	86	92	98	106	113	122	131	140
Corporate Allocation	9	9	9	9	9	9	9	9	9	9
	1,496	1,612	1,715	1,727	1,846	1,915	1,946	2,032	2,161	2,322
Non-controlling Interest	-	4	6	4	0	(4)	(7)	(9)	(12)	(15)
Net Income	149	125	120	184	142	217	267	273	225	292
*Additional General Consumers Revenue										
Percent Increase		2.90%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%
Cumulative Percent Increase		2.90%	6.50%	10.23%	14.09%	18.08%	22.21%	26.49%	30.92%	35.50%

ELECTRIC OPERATIONS (MH10)
PROJECTED BALANCE SHEET
(In Millions of Dollars)

For the year ended March 31	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
ASSETS										
Plant in Service	12,648	14,621	15,120	15,661	16,805	17,351	17,908	20,305	21,111	24,927
Accumulated Depreciation	(4,833)	(5,202)	(5,599)	(6,005)	(6,392)	(6,825)	(7,285)	(7,769)	(8,285)	(8,819)
Net Plant in Service	7,815	9,419	9,520	9,656	10,412	10,526	10,623	12,535	12,826	16,108
Construction in Progress	2,621	1,634	2,215	3,090	3,455	4,791	6,040	5,824	7,282	5,520
Current and Other Assets	1,894	1,994	1,784	1,505	1,643	1,842	2,035	2,307	2,073	2,323
Goodwill and Intangible Assets	165	156	140	127	114	107	98	92	105	112
Regulated Assets	217	232	241	249	251	247	235	219	202	187
	12,712	13,434	13,901	14,626	15,876	17,513	19,032	20,978	22,488	24,251
LIABILITIES AND EQUITY										
Long-Term Debt	8,507	8,927	8,949	10,279	11,294	12,969	13,841	15,187	17,073	14,673
Current and Other Liabilities	1,292	1,470	2,056	1,321	1,555	1,394	1,787	2,133	1,542	5,421
Contributions in Aid of Construction	291	291	286	282	278	276	274	272	270	269
Retained Earnings	2,354	2,479	2,595	2,779	2,922	3,139	3,406	3,679	3,904	4,196
Accumulated Other Comprehensive Income	266	266	14	(35)	(173)	(264)	(275)	(293)	(300)	(307)
	12,712	13,434	13,901	14,626	15,876	17,513	19,032	20,978	22,488	24,251

ELECTRIC OPERATIONS
COMPARISON OF MH10 To MH09
INCREASE / (DECREASE)
(In Millions of Dollars)

ACCOUNT	2011	CUMULATIVE 2011-2013	CUMULATIVE 2011-2020	VARIANCE EXPLANATION
REVENUES				
General Consumers Revenue including Projected Rate Increases	2	37	119	Higher residential sales partially offset by lower industrial sales due to economic downturn.
Extraprovincial	60	(116)	(1,106)	Favourable water flows in 2011. Deferral of Keeyask 1 year, lower export prices, stronger Canadian dollar, reduction in wind energy and the changes in the NSP extension export sales and prices contribute to the decrease. Lower Manitoba demand increases dependable energy available for export and partially offsets decreases.
Other	(1)	(2)	(6)	
Total Revenue	**61**	**(81)**	**(992)**	
EXPENSES				
Operating and Administrative	18	19	28	Early adoption of accounting changes in 2011. Revised estimate of Wuskwatim GS operating & administrative.
Finance Expense	(20)	(129)	(451)	Lower average interest rates and stronger Canadian dollr. Deferral of Keeyask 1 year.
Depreciation and Amortization	(12)	(17)	(47)	Decreases in Bill 11 and DSM expenditures. Deferral of Keeyask 1 yr.
Water Rentals and Assessments	10	13	(12)	Favourable water flows in 2011. Deferral of Keeyask 1 year, lower assessments related to costs associated with the NEB, natural gas and water flows, and slightly lower hydraulic generation over the forecast.
Fuel and Power Purchased	(11)	(132)	(808)	Favourable water flows in 2011. Reduction in wind energy, reduced requirement for thermal generation and imports, lower market prices, and stronger Canadian dollar result in decreases over the forecast.
Capital and Other Taxes	5	17	74	Increases to capital program.
Corporate Allocation	(0)	1	4	Increased due to $100 Million of acquisition refinanced at a 0.425% higher rate.
Total Expenses	**(9)**	**(228)**	**(1,212)**	
Non-controlling Interest	-	8	32	Lower revenue and higher operating & administrative costs partially offset by lower interest rates.
Change in Net Income	**70**	**156**	**251**	

13.0 GAS OPERATIONS FINANCIAL FORECAST (CGM10)

GAS OPERATIONS (CGM10)
PROJECTED OPERATING STATEMENT
(In Millions of Dollars)

For the year ended March 31	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
REVENUES										
General Consumers										
at approved rates	416	455	464	453	452	451	450	449	446	444
additional revenue requirement *	0	0	6	11	15	19	23	23	27	32
	416	455	470	464	467	470	473	472	474	476
Cost of Gas Sold	273	311	320	310	309	309	308	306	304	303
Gross Margin	143	144	150	154	158	162	166	166	170	174
Other	2	2	2	2	2	2	2	2	2	2
	145	146	152	156	159	163	168	167	171	175
EXPENSES										
Operating and Administrative	63	64	65	67	68	69	71	72	74	75
Finance Expense	18	19	20	21	23	23	24	24	24	25
Depreciation and Amortization	26	27	30	32	34	34	36	37	39	39
Capital and Other Taxes	19	20	20	20	20	20	20	21	21	21
Corporate Allocation	12	12	12	12	12	12	12	12	12	12
	138	142	147	151	156	159	163	165	169	171
Net Income	6	4	5	5	3	4	5	2	2	4
*Additional Revenue Requirement										
Percent Increase		0.00%	1.50%	1.00%	1.00%	1.00%	1.00%	0.00%	1.00%	1.00%
Cumulative Percent Increase		0.00%	1.50%	2.52%	3.54%	4.58%	5.62%	5.62%	6.68%	7.74%

GAS OPERATIONS (CGM10)
PROJECTED BALANCE SHEET
(In Millions of Dollars)

For the year ended March 31	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
ASSETS										
Plant in Service	620	634	656	683	701	715	733	755	780	806
Accumulated Depreciation	(217)	(221)	(230)	(240)	(251)	(257)	(269)	(281)	(293)	(307)
Net Plant in Service	403	413	426	442	450	457	465	475	487	499
Construction in Progress	3	1	1	1	1	1	1	1	1	1
Current and Other Assets	105	105	105	105	104	104	104	104	104	104
Intangible Assets	6	10	9	8	7	6	5	5	4	4
Regulated Assets	75	80	83	84	83	83	80	76	69	62
	593	609	624	639	645	651	656	661	665	671
LIABILITIES AND EQUITY										
Long-Term Debt	327	265	335	310	355	355	355	355	355	355
Current and Other Liabilities	72	147	89	123	81	84	84	88	91	93
Contributions in Aid of Construction	33	32	31	33	32	31	30	30	29	28
Share Capital	121	121	121	121	121	121	121	121	121	121
Retained Earnings	40	43	48	53	56	61	65	67	69	73
	593	609	624	639	645	651	656	661	665	671

GAS OPERATIONS
COMPARISON OF CGM10 To CGM09
INCREASE / (DECREASE)
(In Millions of Dollars)

ACCOUNT	2011	CUMULATIVE 2011-2013	CUMULATIVE 2011-2020	VARIANCE EXPLANATION
REVENUES				
General Consumers Revenue at approved rates	(63)	(127)	(484)	Lower due to decreased gas prices and volumes and increased funding for the Furnace Replacement Program of $3.8 million annually throughout the forecast period.
Projected Rate Increases	-	(8)	(0)	Lower due to the deferral of the 1.50% rate increase from 2012 to 2013. Nearly offset over time by revised rate increase requirements.
Cost of Gas Sold	(59)	(114)	(416)	Lower due to decreased gas prices and volumes.
Other	0	0	1	Higher due to increased late penalty charges. Partially offset by decreased broker revenue.
Total Revenue	**(3)**	**(21)**	**(67)**	
EXPENSES				
Operating and Administrative	2	5	16	Higher due to a provision for increased expenditures.
Finance Expense	(3)	(11)	(29)	Lower primarily due to a decrease in short-term debt volume. Partially offset by increased volume of new long-term debt issued, which is in part offset by a decrease in long-term debt rates on existing debt.
Depreciation and Amortization	(0)	(2)	(5)	Lower primarily due to favourable capital spending in 2009/10 combined with IFRS revisions to DSM. Partially offset by the addition of Gas Scada.
Capital and Other Taxes	(4)	(11)	(40)	Lower primarily due to a decrease in property taxes from the 2010 provincial reassessment.
Total Expenses	**(5)**	**(19)**	**(57)**	
Change in Net Income	**1**	**(2)**	**(10)**	

14.0 CORPORATE SUBSIDIARIES FINANCIAL FORECAST (CS10)

CORPORATE SUBSIDIARIES (CS10)
PROJECTED OPERATING STATEMENT
(In Millions of Dollars)

For the year ended March 31	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
REVENUES										
Revenues	19	22	23	24	24	25	25	26	26	27
	19	22	23	24	24	25	25	26	26	27
EXPENSES										
Operating and Administrative	15	16	16	17	17	17	18	18	18	19
Finance Expense	0	0	0	0	0	0	0	0	0	0
Depreciation and Amortization	1	1	1	1	1	1	1	1	1	1
Capital and Other Taxes	0	0	0	0	0	0	0	0	0	0
	16	17	17	18	18	18	19	19	19	20
Net Income (Loss)	4	5	6	6	6	7	7	7	7	7