Manitoba Hydro

November 2009

Integrated Financial Forecast (IFF09-1)

2009/10 – 2019/20

Financial Planning

Finance & Administration

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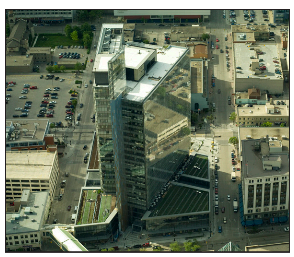
INTEGRATED FINANCIAL FORECAST (IFF09-1)

Section 1

KEY FINANCIAL RESULTS
(Dollars are in millions)

	Actual	IFF09-1 Forecast		
	2008/09	**2009/10**	**2010/11**	**2011/12**
PROJECTED RATE INCREASES - ELECTRIC - GAS (non-commodity)	 5.0% 1.0%	 2.9% -	 2.9% -	 2.9% 1.5%
NET INCOME ($ Millions) - ELECTRIC - GAS - SUBSIDIARIES	 $285 $9 $4	 $121 $4 $4	 $78 $5 $5	 $87 $6 $5
CAPITAL EXPENDITURES ($ Millions) - ELECTRIC - GAS	 $893 $39	 $1,067 $37	 $1,047 $38	 $995 $41
INTEREST COVERAGE RATIO	1.58	1.24	1.15	1.15
DEBT/EQUITY RATIO	75:25	74:26	75:25	76:24
CAPITAL COVERAGE RATIO (excl. new major generation & transmission)	1.81	1.39	1.09	1.14

1.0 OVERVIEW

1.1 INTRODUCTION

This Consolidated Integrated Financial Forecast (IFF09-1) projects Manitoba Hydro's financial results over the period 2009/10 to 2019/20. Segmented forecasts prepared for the electricity (MH09-1), natural gas (CGM09-1), and electric subsidiaries (ES09-1) are included. This forecast reflects the actual hydraulic conditions as of August 2009, new or enhanced resources assumed in the 2009 Power Resource Plan, and capital expenditures forecast in CEF09-1.

1.2 HIGHLIGHTS

- **Electricity Rates:** The base forecast includes the PUB-approved 2.9% average rate increase effective April 1, 2009. Additional average rate increases of 2.9% per year are projected for April 1, 2010 and April 1, 2011 followed by 3.5% per year to 2019/20. 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 forecast assumes a 1.5% general rate increase effective May 1, 2011. Subsequent general rate increases are assumed to be effective May 1 of 2013, 2015, 2017, 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. Gas rate applications are also subject to review and approval of the Manitoba Hydro Board.

- **Consolidated Net Income:** Consolidated net income is forecasted to be $129 million in 2009/10, down $95 million from the $224 million forecasted in IFF08-1. The decrease in net income is mainly attributable to lower domestic and net export revenues due to the current economic downturn. This reduction to net income is partially offset by lower finance expense due to favourable interest rates.

- **Export Sales:** The forecast assumes that the term sheets negotiated for the 250 MW Minnesota Power and 500 MW Wisconsin Public Service long-term firm sales as well as 375/500 MW Northern States Power extension will be finalized into long-term firm contracts.

- **New Generation:** Construction of the Wuskwatim generating station (200 MW) is proceeding, with the first unit planned to come into service in September, 2011.

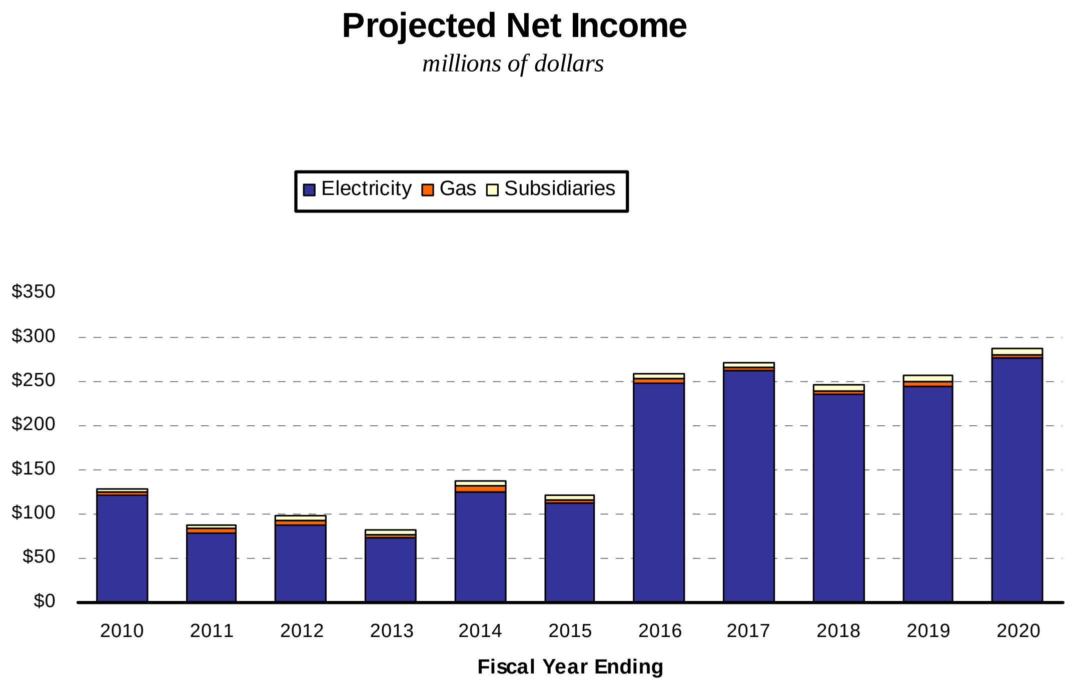
  The Keeyask generating station (630 MW) is planned to come into service in 2018/19 in order to meet new export demands and domestic load growth. Negotiations concluded with Tataskweyak, War Lake, Fox Lake and York Factory Cree Nations resulting in the Joint Keeyask Development Agreement being ratified by the communities and signed in May 2009. This forecast assumes the Keeyask Cree Nations will acquire up to 25% of total units issued in the Keeyask Hydro Limited Partnership.

  Other assumptions related to new generation include 300 MW of additional wind capacity and the Conawapa generating station (1300 net MW) first unit in-service in 2022/23. The potential reduction in wind generation from 300MW to 138MW will not have a significant impact on forecast results.

- **New Major Transmission:** IFF09-1 assumes a 1000 MW export and 750 MW import interconnection from Dorsey to the US border planned for June, 2018 in order to meet the obligations of the new firm export sales. 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 provide sufficient capacity for future northern generation.

- **The Capital Expenditure Forecast (CEF09-1):** The 2009 capital forecast, totalling $16.5 billion to 2019/20, is comprised of $11.8 billion of new major generation and transmission projects and $4.7 billion for other capital requirements including necessary system refurbishment and upgrades.

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



2.0 ASSUMPTIONS

2.1 ECONOMIC VARIABLES

The economic assumptions used in the forecast are based upon Manitoba Hydro's Spring 2009 Economic Outlook revised in July for current economic conditions. Exchange rates and interest rates have been updated in October to reflect the recent strengthening of the Canadian dollar and revisions to interest rates. Projected rates for key economic indicators are listed below with the 2008 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
2009/10	0.6% (2.0%)	0.45% (4.05%)	4.60% (5.30%)	1.11 (1.06)
2010/11	1.9% (2.0%)	1.40% (4.60%)	4.65% (5.85%)	1.07 (1.06)
2011/12	2.0% (2.0%)	3.60% (4.60%)	5.20% (5.95%)	1.09 (1.07)
2012/13	2.0% (2.0%)	4.30% (4.60%)	5.70% (6.25%)	1.07 (1.07)
2019/20	2.0% (2.0%)	4.45% (4.60%)	6.10% (6.45%)	1.14 (1.10)

*Excluding Provincial Guarantee Fee of 1.0%

2.2 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.

2.3 ELECTRICITY DEMAND AND SUPPLY

2.3.1 Manitoba Electricity Load Forecast

Relative to last year's forecast, the May 2009 Electric Load Forecast projects Manitoba electrical requirements to be 834 GW.h lower in 2018/19. Net total peak is forecast to be 148 MW lower. Average annual growth is 1.5% for net firm energy and 1.3% for net total peak (compared to 1.6% and 1.4%, respectively, in IFF08-1) over the forecast period to 2018/19.

Projected load growth in the general service class, (which represents 66% of all sales by volume) is lower than last year's forecast by more than 10,000 GW.h over the period to 2018/19 primarily due to lower projected consumption in the primary metals and chemical & treatment sectors as a result of the economic downturn. Reductions in general service volumes are offset somewhat by higher growth in residential sector compared to IFF08-1.

Due to the reduced load projections for many of Manitoba Hydro's potential energy intensive customers, the revenue forecast under this rate structure is lower than that forecast in IFF08-1.

2.3.2 Extraprovincial Sales and Production Costs

As in the previous forecast, IFF09-1 includes the following long-term firm sales (contracts under negotiation):

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

Net export revenue is $43 million and $17 million lower in 2009/10 and 2010/11, respectively, compared to IFF08-1 reflecting current lower export market prices. Over the period to 2018/19, there is a projected increase in net export revenues of $212 million compared to the previous forecast which is mainly attributable to lower domestic demand. Export revenues for 2011/12 and on assume the same export price forecast as 2008.

2.3.3 Demand Side Management

IFF09-1 includes DSM projections from the 2009 Power Smart Plan to achieve the Corporate target for further electrical savings of 644 MW and 2,053 GW.h by 2024/25. Combined with savings achieved to date, total electrical savings of 915 MW and 3,271 GW.h are forecast for 2024/25. There is also a plan to achieve natural gas savings of 172 million cubic meters.

2.3.4 Electricity Supply

Manitoba Hydro's 2009 Power Resource Plan describes the Corporation's current expectations for new or enhanced major sources of electricity generation and major 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. Planned in-service for Keeyask and Conawapa are unchanged from the previous forecast. The Pointe du Bois powerhouse rebuild is currently under review and has been deferred beyond the IFF period. This forecast assumes a new spillway and dam will be constructed to replace existing spillway structures.

	Net MW	**Dependable GW.h**	**In-Service Date**
Brandon #5 License Review	105	811	Restricted operation to 2018/19
Wuskwatim	200	1,250	First power 2011
Keeyask	630	2,900	First power 2018
Conawapa	1300	4,550	First power 2022
Additional Wind Capacity	Up to 300	934	2010/11 to 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	89	243	2017/18
Demand Side Management Program			
Planned Additional	269	1,158	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. Excavation for the principal structures commenced in December 2007 and was completed in February 2009. The first concrete for the station's spillway structure began in May 2009 and it is anticipated there will be approximately 65,000 cubic meters of concrete placed this year including completion of the Spillway, Service Bay and concrete to a sufficient elevation to allow for the enclosure of the Powerhouse. By this time next year, the spillway gates should be in place and the remainder of the concrete structures is expected to be nearing completion. Construction work is proceeding to achieve a first unit in-service of September, 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. Currently, approximately 84% of customers representing approximately 58% 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 slightly lower than last year's forecast. The total natural gas sales volume forecast is down 2 million cubic meters (0.1%) in 2009/10 and down 5 million cubic meters (0.3%) in 2018/19. The Special Contract and Industrial volume forecasts are expected to decrease due to lower consumption expectations resulting from decreased usage in 2008/09. This decrease is partially offset by the Residential and Large General Service volume forecasts, which are expected to increase due to a combination of customer growth and an increase in the ten year average of normal degree days heating.

The Residential 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.

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

Operating, Maintenance & Administrative (OM&A) Expenses in IFF09-1 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 and ongoing efforts to restrain expenditures throughout the Corporation, a number of measures have been put in place or are underway to hold the annual rates of OM&A increases to 1.9% in 2009/10, 2.2% in 2010/11 and 1.3% in 2011/12 (rates of increase are after adjustments for CICA accounting changes and expense reclassifications). These relatively low rates of OM&A increases are despite higher wage and benefit settlements with bargaining units, higher pension costs related to fund performance, and considerably higher costs related to the aging generation, transmission and distribution infrastructure. In addition, Manitoba Hydro is incurring increased costs to serve an expanding customer base and higher costs associated with environmental regulations.

The OM&A cost saving measures include the following:

a) Restrictions on all out-of-province travel (essential travel requires the specific approval of the President & CEO);
b) Implementation of the Workforce Management Project (will improve customer service response times and reduce travel and idle times);
c) Expansion of customer self-service initiatives (including e-permits for electrical contractors and e-billing and payment services);
d) Selective reduction of staff positions through attrition (mainly through retirements);
e) Rationalization of vehicle fleet and equipment;
f) Reductions to the numbers of summer student hires (summer replacement staff);
g) Reductions to memberships in external associations and organizations;
h) Extensions to lives of computers and other computing equipment;
i) Reductions to sponsorships, donations and grants; and

j) Reductions to staffing at selective generating stations during off-peak hours.

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 2011/12 fiscal year (including comparative information for 2010/11). 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, employee benefits and the first-time adoption of IFRS (IFRS1). This forecast includes a general provision of $15 million annually commencing in 2011/12 pertaining to anticipated impacts of the transition to IFRS. The provision is only an estimate at this time and further analysis will be required to assess the final impacts of the adoption of IFRS.

Other Canadian accounting standard changes incorporated in this forecast include $11 million annually effective April 1, 2009 for research related expenditures associated with intangible assets and general and administrative costs no longer eligible for deferral.

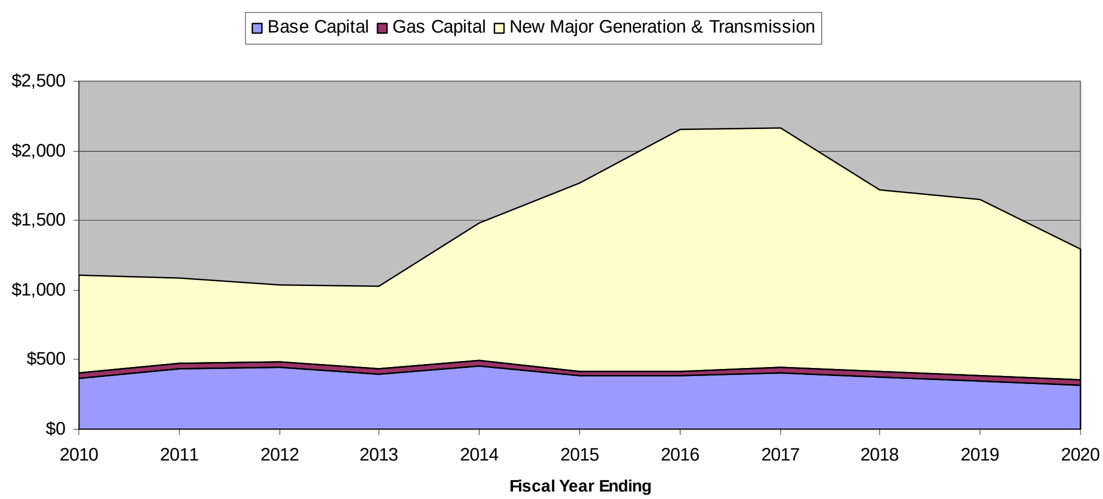
5.0 CAPITAL EXPENDITURE FORECAST (CEF09-1)

Projected capital expenditures for the period 2009/10 to 2019/20 total $16.5 billion which is consistent with the level of capital expenditures in CEF08-1. Annual capital expenditures vary from CEF08-1 from year to year reflecting revised project plans and patterns of historical spending.

CAPITAL EXPENDITURE FORECAST (CEF09-1)
(In Millions of Dollars)

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Total
New Major Generation & Transmission	808	681	599	623	844	1,318	1,843	1,748	1,284	1,409	1,167	12,326
Other Electric	447	484	475	416	384	374	404	412	369	392	390	4,547
Subtotal Electric	1,255	1,165	1,075	1,039	1,228	1,692	2,248	2,161	1,653	1,800	1,558	16,873
Gas	37	38	41	45	37	36	37	37	38	39	39	424
Consolidated Target Adjustment	(188)	(119)	(80)	(59)	221	37	(129)	(33)	25	(188)	(306)	(817)
Total Capital Expenditures	1,104	1,085	1,036	1,025	1,486	1,765	2,156	2,165	1,716	1,651	1,291	16,480

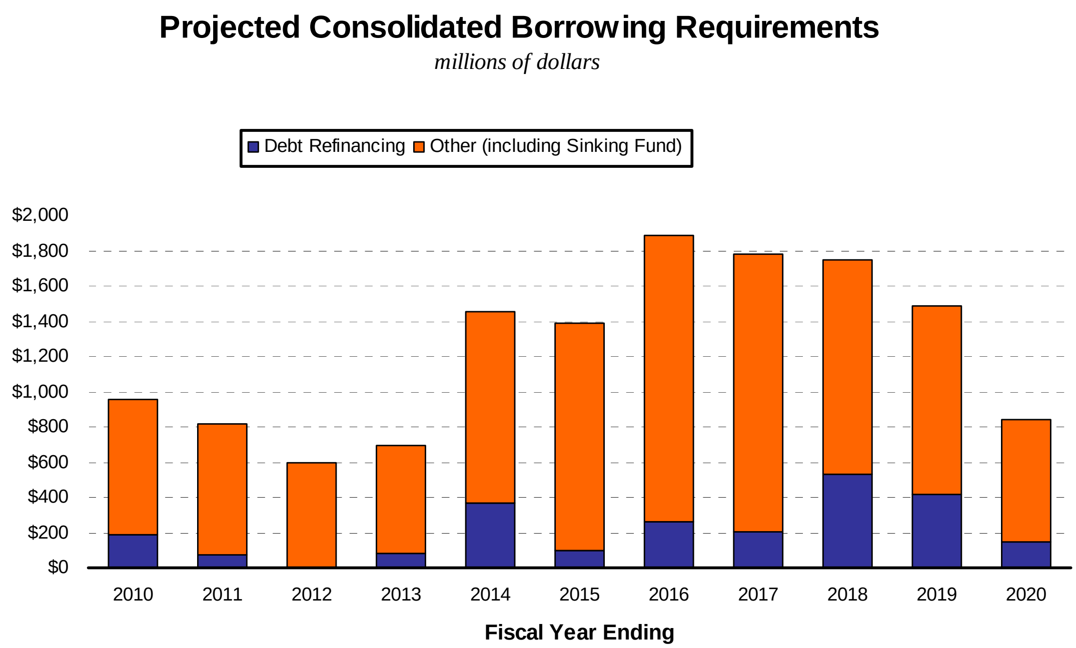
Projected Capital Expenditures
Major Categories
millions of dollars



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 policy 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 21% of Manitoba Hydro's debt is in floating rate instruments.



7.0 FINANCIAL RATIOS

The following graphs depict the impact of IFF09-1, compared to IFF08-1, on Manitoba Hydro's financial targets.

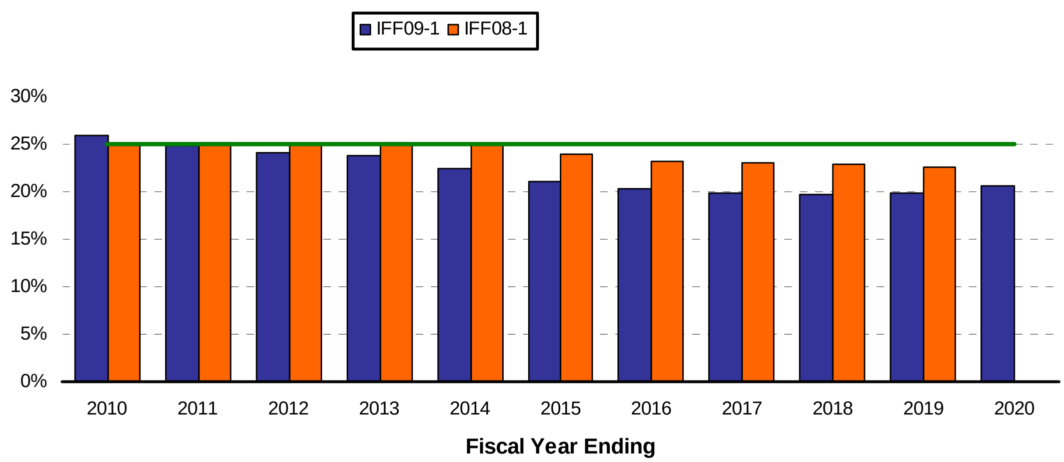
Financial Targets	
Debt/Equity Ratio	Maintain a minimum debt/equity ratio of 75:25
Interest Coverage	Maintain an annual gross interest coverage ratio of greater than 1.20
Capital Coverage	Maintain a capital coverage ratio of greater than 1.20 (excepting new major generation and transmission)

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. The recent favourable water flow conditions enabled the achievement of an equity target of 25% in 2008/09 for the first time in Corporate history. However, due to major investments in the generation and transmission system over the next decade, this ratio is projected to regress to 80:20 between 2015/16 to 2018/19 and then to recover strongly thereafter.

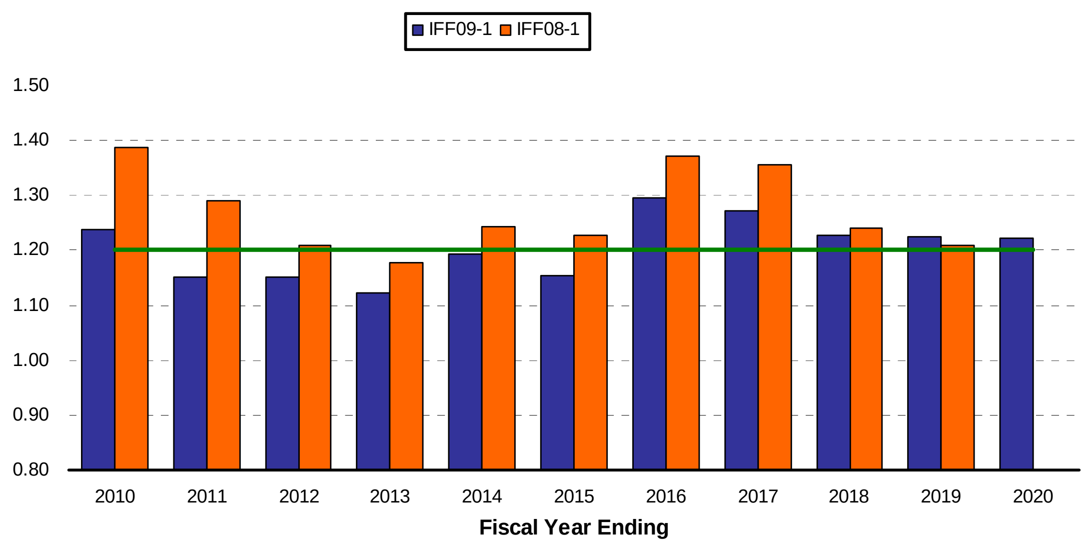
Projected Consolidated Equity Ratio



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 lower domestic and export revenues over the early years of the forecast result in the interest coverage ratio slipping below 1.20 up to 2014/15.

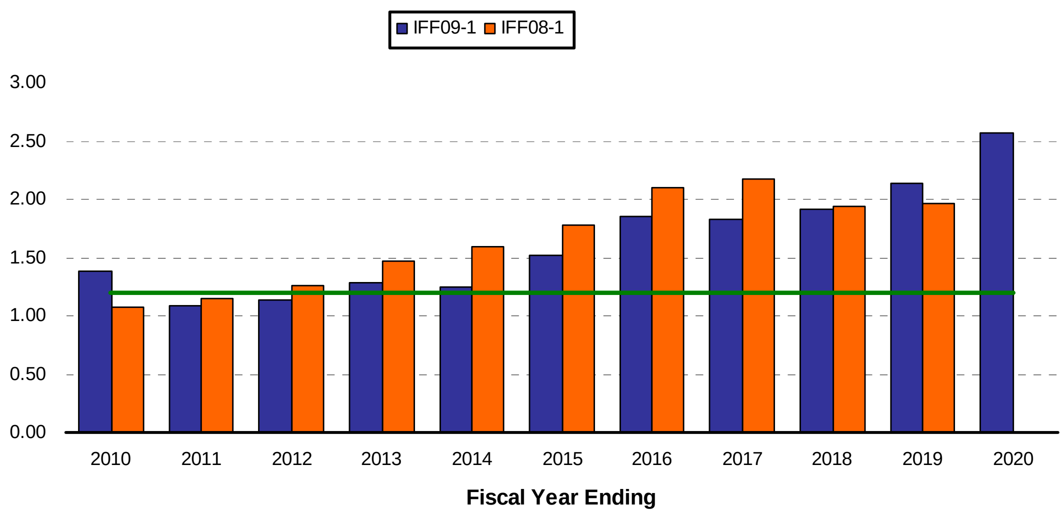
Projected Consolidated Interest Coverage Ratio



7.3 CAPITAL COVERAGE RATIO

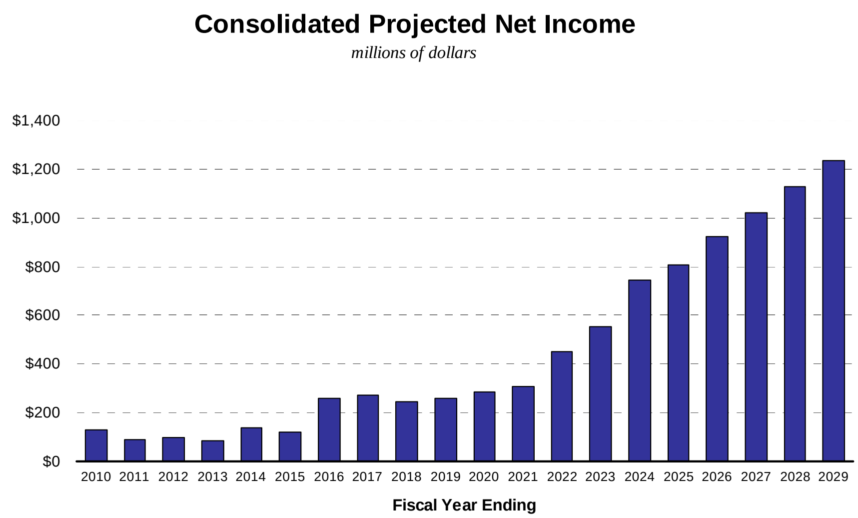
Capital coverage measures the ability of current period internally generated funds to finance capital expenditures with the exception of major new generation and related transmission. The capital coverage target is met for most of the forecast period. In the two years in which targets are not projected to be met, management will continue to closely monitor base capital expenditures and seek opportunities to defer expenditures as may be appropriate (without compromising safety, reliability and efficiency).

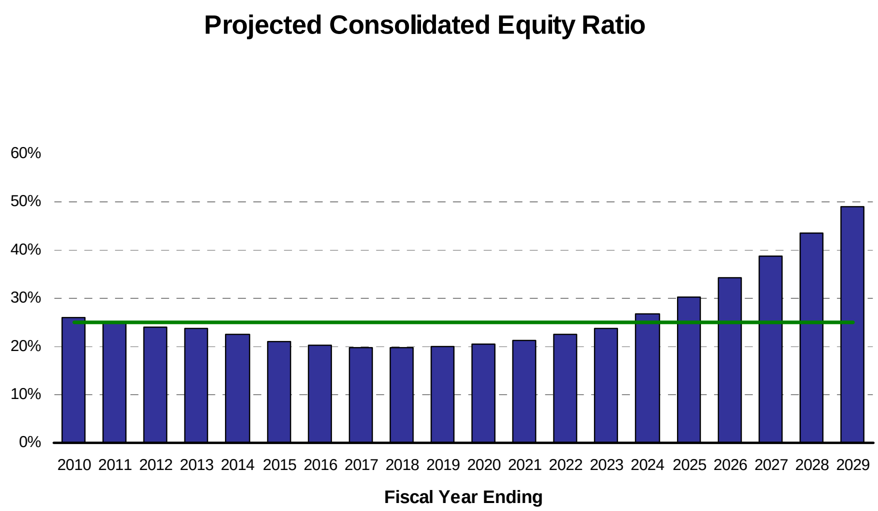
Projected Consolidated Capital Coverage Ratio



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 very significant. This is depicted in the following graphs which, for illustrative purposes, incorporate average annual rate increases in the period following IFF09-1 which are identical to the projected rates of inflation (2.0%).





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 IFF09-1 necessary to offset the risks outlined above.

	2011/12	2015/16	2019/20	Incremental Annual Rate Increase/(Decrease) *	
	Incremental Increase/(Decrease) in Retained Earnings (in millions of dollars)			Electric	Gas
IFF09-1 Baseline	**2,396**	**2,997**	**4,059**	-	-
+ 1% Interest Rates	26	(14)	(279)	0.23%	0.06%
- 1% Interest Rates	(24)	13	254	-0.23%	-0.06%
Cdn $ down $0.10 US	33	142	358	-0.34%	N/A
Cdn $ up $0.10 US	(26)	(115)	(286)	0.27%	N/A
Low Export Prices	(54)	(363)	(920)	1.05%	N/A
High Export Prices	113	712	1,713	-2.10%	N/A
5 Year Drought (starting in 2011/12)	N/A	(2,405)	N/A	3.37%	N/A
Medium High Electric Load Forecast	13	(3)	(9)	0.01%	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 2019/20 as in the base MH09-1 and CGM09-1.

Interest rates and foreign exchange

For the foreign exchange rate sensitivities and +/- 1% interest rate sensitivities rates were adjusted beginning in fiscal year 2010/11. 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 MH09-1 and CGM09-1 begin in fiscal year 2011/12.

Export prices

Manitoba Hydro has developed an 'Expected' forecast of power prices for export which is used in the MH09-1 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 2011/12 and 2019/20, net revenue would decline $772 million under the Low price forecast and increase $1,412 million under the High price forecast compared to the Expected price forecast.

Manitoba load growth

The base load forecast used in MH09-1 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 future growth in the Province. Retained earnings are nearly indifferent when comparing the load growth scenario to the base case due to marginal domestic energy prices approaching export prices.

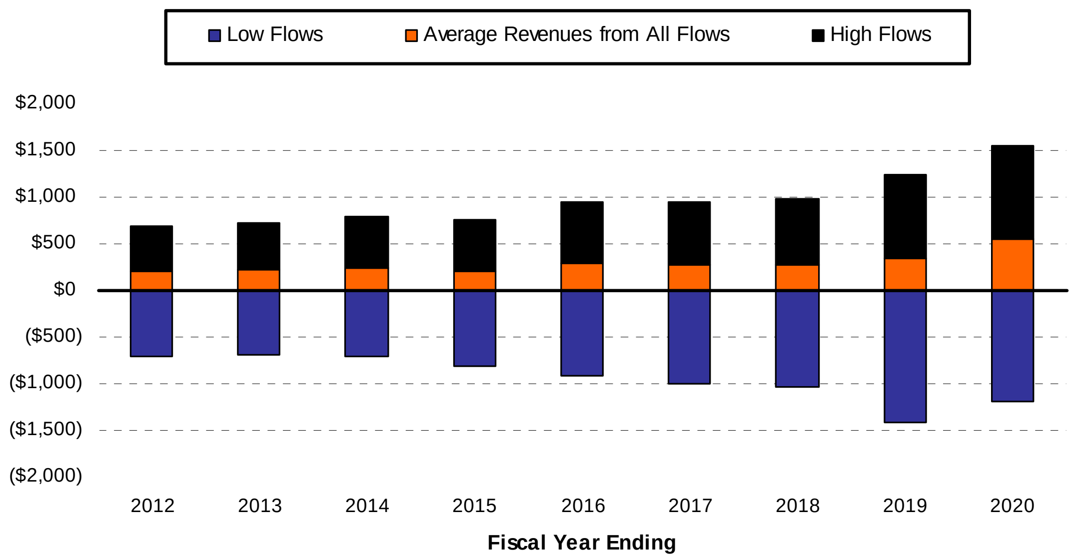
Water conditions

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 2011/12 and extending to 2015/16. 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 by $2.4 billion (including financing costs) compared to MH09-1. If a drought of this magnitude (or the even larger 1936 - 1943 drought) were to coincide with a period of high prices for thermal generation and import purchases the impact would be greater.

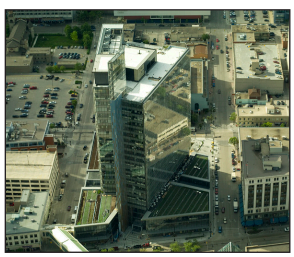
The graph below shows the variability in net export revenues due to fluctuations in water flows. The asymmetry between the benefits of high flows and the costs of low flows is due to the fact that in high years, water is spilled as a result of system design constraints and to the requirements for thermally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

Variability in Net Export Revenue

millions of dollars



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

10.0 PROJECTED CONSOLIDATED FINANCIAL STATEMENTS (IFF09-1)

CONSOLIDATED PROJECTED OPERATING STATEMENT (IFF09-1)
(In Millions of Dollars)

For the year ended March 31	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
REVENUES											
General Consumers	1,652	1,670	1,739	1,808	1,869	1,953	2,028	2,101	2,178	2,256	2,336
Extraprovincial	414	383	554	583	615	590	701	729	742	894	1,093
	2,066	2,054	2,293	2,390	2,484	2,543	2,729	2,830	2,920	3,151	3,429
Cost of Gas Sold	351	332	340	346	342	349	350	351	352	353	352
	1,715	1,722	1,953	2,044	2,142	2,193	2,379	2,479	2,568	2,798	3,077
Other	28	29	31	32	32	33	34	34	35	36	36
	1,742	1,751	1,984	2,076	2,174	2,227	2,412	2,513	2,603	2,834	3,113
EXPENSES											
Operating and Administrative	446	456	482	492	501	512	522	532	555	568	589
Finance Expense	454	451	509	569	570	588	574	590	632	719	923
Depreciation and Amortization	394	415	438	469	481	502	513	519	540	573	607
Water Rentals and Assessments	120	110	111	113	114	114	115	115	115	115	124
Fuel and Power Purchased	103	131	248	249	259	268	296	341	362	440	418
Capital and Other Taxes	97	99	100	104	109	116	125	134	140	146	150
	1,613	1,663	1,888	1,995	2,035	2,100	2,144	2,231	2,344	2,562	2,812
Non-controlling Interest	-	-	1	1	(2)	(5)	(9)	(11)	(12)	(15)	(14)
Net Income	129	88	98	83	137	122	260	271	246	257	287
Additional General Consumers Revenue											
General electricity rate increases		2.90%	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%	0.00%	1.00%	0.00%	1.00%	0.00%	1.00%	1.00%	0.00%
Financial Ratios											
Debt:Equity	74:26	75:25	76:24	76:24	78:22	79:21	80:20	80:20	80:20	80:20	79:21
Interest Coverage	1.24	1.15	1.15	1.12	1.19	1.15	1.30	1.27	1.23	1.22	1.22
Capital Coverage	1.39	1.09	1.14	1.28	1.25	1.52	1.86	1.83	1.91	2.14	2.56

CONSOLIDATED PROJECTED BALANCE SHEET (IFF09-1)
(In Millions of Dollars)

For the year ended March 31	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
ASSETS											
Plant in Service	13,097	13,626	15,691	16,213	16,654	17,387	17,844	18,579	21,071	22,401	25,835
Accumulated Depreciation	(4,800)	(5,171)	(5,562)	(5,985)	(6,414)	(6,864)	(7,320)	(7,787)	(8,275)	(8,799)	(9,357)
Net Plant in Service	8,297	8,455	10,129	10,228	10,240	10,523	10,524	10,792	12,796	13,602	16,478
Construction in Progress	1,949	2,460	1,343	1,820	2,840	3,856	5,534	6,950	6,161	6,448	4,170
Current and Other Assets	2,421	2,374	2,503	2,551	2,328	2,482	2,673	2,885	3,191	2,975	3,309
Goodwill	107	107	107	107	107	107	107	107	107	107	107
	12,775	13,397	14,082	14,705	15,516	16,968	18,838	20,734	22,256	23,133	24,065
LIABILITIES AND EQUITY											
Long-Term Debt	7,816	8,613	9,071	8,786	10,366	11,522	13,140	14,429	15,363	16,446	14,164
Current and Other Liabilities	2,246	2,000	2,187	2,983	2,165	2,365	2,391	2,750	3,104	2,645	5,573
Contributions in Aid of Construction	293	291	285	280	276	273	272	270	268	267	267
Retained Earnings	2,227	2,315	2,396	2,479	2,616	2,738	2,997	3,268	3,515	3,772	4,059
Accumulated Other Comprehensive Income	192	178	143	178	94	71	38	17	6	3	3
	12,775	13,397	14,082	14,705	15,516	16,968	18,838	20,734	22,256	23,133	24,065
Debt:Equity Ratio	74:26	75:25	76:24	76:24	78:22	79:21	80:20	80:20	80:20	80:20	79:21

CONSOLIDATED PROJECTED CASH FLOW STATEMENT (IFF09-1)
(In Millions of Dollars)

For the year ended March 31	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
OPERATING ACTIVITIES											
Cash Receipts from Customers	2,171	2,159	2,401	2,495	2,590	2,649	2,836	2,938	3,029	3,261	3,540
Cash Paid to Suppliers and Employees	(1,175)	(1,227)	(1,364)	(1,382)	(1,414)	(1,441)	(1,493)	(1,561)	(1,613)	(1,712)	(1,726)
Interest Paid	(474)	(445)	(504)	(568)	(578)	(577)	(582)	(594)	(662)	(753)	(943)
Interest Received	29	22	14	16	14	4	15	26	36	39	33
	551	510	547	561	613	636	777	810	790	834	904
FINANCING ACTIVITIES											
Proceeds from Long-Term Debt	900	800	600	600	1,600	1,400	1,800	1,800	1,800	1,400	1,000
Sinking Fund Withdrawals	262	227	27	103	483	-	3	-	-	456	171
Retirement of Long-Term Debt	(448)	(304)	(27)	(183)	(849)	(100)	(262)	(201)	(530)	(869)	(321)
Other	(36)	(12)	19	(10)	(13)	(11)	(13)	(14)	(14)	(26)	(15)
	678	712	619	509	1,220	1,289	1,529	1,585	1,255	961	835
INVESTING ACTIVITIES											
Property, Plant and Equipment, net of contributions	(1,151)	(1,117)	(1,046)	(1,035)	(1,495)	(1,774)	(2,163)	(2,173)	(1,723)	(1,658)	(1,299)
Sinking Fund Payment	(94)	(99)	(98)	(116)	(176)	(107)	(201)	(159)	(242)	(200)	(256)
Other	(36)	(20)	(16)	(17)	(17)	(31)	(29)	(41)	(28)	(27)	(27)
	(1,281)	(1,236)	(1,160)	(1,168)	(1,687)	(1,912)	(2,393)	(2,372)	(1,993)	(1,885)	(1,582)
Net Increase (Decrease) in Cash	(52)	(15)	6	(98)	146	12	(87)	23	52	(90)	157
Cash at Beginning of Year	(32)	(84)	(99)	(92)	(190)	(44)	(32)	(119)	(96)	(44)	(133)
Cash at End of Year	(84)	(99)	(92)	(190)	(44)	(32)	(119)	(96)	(44)	(133)	24

11.0 CAPITAL EXPENDITURE FORECAST (CEF09-1)

CAPITAL EXPENDITURE FORECAST SUMMARY TABLE (CEF09)
(in millions of dollars)

	Total Project Cost	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	11 Year Total
ELECTRIC													
Major New Generation & Transmission													
Wuskwatim - Generation	1,274.6	364.4	275.3	105.1	12.1	-	-	-	-	-	-	-	756.8
Wuskwatim - Transmission	316.3	90.1	30.5	18.9	-	-	-	-	-	-	-	-	139.5
Herblet Lake - The Pas 230 kV Transmission	93.2	41.9	30.4	7.2	1.9	-	-	-	-	-	-	-	81.5
Keeyask - Generation	4,591.6	67.7	85.0	195.3	198.6	182.3	485.5	799.1	808.3	584.7	537.5	263.9	4,207.9
Conawapa - Generation	6,324.8	60.4	60.4	75.0	111.8	190.1	231.5	308.2	290.3	513.6	846.1	881.7	3,569.2
Kelsey Improvements & Upgrades	189.6	45.1	6.8	0.5	-	-	-	-	-	-	-	-	52.5
Kettle Improvements & Upgrades	75.6	11.1	18.4	6.6	20.1	18.6	-	-	-	-	-	-	74.8
Pointe du Bois - Generation	318.0	13.8	14.8	15.5	53.0	83.1	110.7	-	-	-	-	-	290.9
Pointe du Bois - Transmission	85.9	9.0	26.3	10.4	20.6	13.9	3.1	-	-	-	-	-	83.2
Bipole 3	2,247.8	16.6	21.4	36.7	113.4	266.5	420.2	627.7	557.9	159.9	-	-	2,220.4
Riel 230/500 kV Station	267.6	36.1	58.4	79.6	45.1	38.2	4.6	-	-	-	-	-	262.0
Firm Import Upgrades	4.8	0.6	2.1	2.1	-	-	-	-	-	-	-	-	4.8
Dorsey - US Border New 500 kV Transmission Line	204.8	-	0.5	1.9	8.2	17.6	32.4	79.3	64.8	-	-	-	204.8
Brandon Combustion Turbine Pipeline Upgrade	5.4	5.4	-	-	-	-	-	-	-	-	-	-	5.4
Demand Side Management - Electric	NA	40.3	43.0	42.5	38.4	33.9	29.9	29.0	27.1	25.6	25.1	21.8	356.5
Planning Study Costs	NA	5.7	8.0	1.9	-	-	-	-	-	-	-	-	15.6
		808.1	681.5	599.4	623.1	844.1	1,318.0	1,843.4	1,748.4	1,283.8	1,408.7	1,167.4	12,325.8
New Head Office													
New Head Office	278.1	14.8	-	-	-	-	-	-	-	-	-	-	14.8
Corporate Relations													
Waterways Management Program	NA	5.3	5.4	-	-	-	-	-	-	-	-	-	10.7

CAPITAL EXPENDITURE FORECAST SUMMARY TABLE (CEF09)
(in millions of dollars)

	Total Project Cost	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	11 Year Total
Power Supply													
Converter Transformer Bushing Replacement	5.9	0.1	0.4	1.9	-	-	-	-	-	-	-	-	2.3
Bipole 1 & 2 Electrode Line Monitoring	1.7	0.0	0.0	1.6	-	-	-	-	-	-	-	-	1.6
Dorsey Synchronous Condenser Refurbishment	32.3	3.0	2.5	3.6	2.5	2.6	2.8	-	-	-	-	-	17.0
HVDC Bipole 1 Roof Replacement	5.9	0.7	-	-	-	-	-	-	-	-	-	-	0.7
HVDC System Transformer & Reactor Fire Protection & Prevention	10.4	0.3	1.3	0.3	-	-	-	-	-	-	-	-	1.9
HVDC AC Filter PCB Capacitor Replacement	34.5	2.4	6.0	-	-	-	-	-	-	-	-	-	8.3
HVDC Transformer Replacement Program	105.7	1.0	1.1	7.3	5.3	1.1	-	-	-	-	-	-	15.8
Dorsey 230 kV Relay Building Upgrade	73.8	1.1	1.9	4.0	16.4	32.1	12.0	4.9	-	-	-	-	72.5
HVDC Stations Ground Grid Refurbishment	4.3	0.6	0.5	0.6	0.6	0.0	-	-	-	-	-	-	2.3
HVDC Bipole 2 230 kV HLR Circuit Breaker Replacement	9.4	2.7	0.4	-	-	-	-	-	-	-	-	-	3.1
HVDC Bipole 1 Pole Differential Protection	3.3	-	1.0	2.3	-	-	-	-	-	-	-	-	3.3
HVDC Bipole 1 By-Pass Vacuum Switch Removal	20.4	0.5	4.6	8.2	5.6	1.2	-	-	-	-	-	-	20.1
HVDC Bipole 2 Refrigerant Condenser Replacement	11.0	-	-	2.8	7.2	1.0	-	-	-	-	-	-	11.0
HVDC Bipole 1 Smoothing Reactor Replacement	31.8	0.0	0.1	0.1	0.1	4.0	18.0	7.2	2.5	-	-	-	31.8
HVDC Bipole 1 Converter Station, P1 & P2 Battery Bank Separation	3.2	-	0.0	1.0	2.2	-	-	-	-	-	-	-	3.2
HVDC Bipole 1 DCCT Transductor Replacement	11.7	-	0.6	2.8	0.8	3.9	1.1	2.3	0.1	-	-	-	11.7
HVDC BP1 & BP2 DC Converter Transformer Bushing Replacements	8.7	-	-	0.5	1.0	1.7	5.2	0.2	-	-	-	-	8.7
HVDC Bipole 2 Valve Hall Wall Bushing Replacements	19.2	-	0.1	3.3	4.5	4.6	4.7	2.0	-	-	-	-	19.2
HVDC Bipole 1 CQ Disconnect Replacement	5.2	-	0.0	1.1	1.5	0.9	1.0	0.6	-	-	-	-	5.2
HVDC Bipole 2 Thyristor Module Cooling Refurbishment	4.7	1.8	1.7	0.8	-	-	-	-	-	-	-	-	4.3
HVDC Bipole 2 Smoothing Reactor Replacement	17.1	0.8	3.5	3.2	5.7	3.8	-	-	-	-	-	-	17.1
HVDC Bipole 1 Transformer Marshalling Kiosk Replacement	6.8	1.0	1.0	1.6	1.6	1.1	0.5	-	-	-	-	-	6.8
Pine Falls Rehabilitation	56.2	2.8	4.2	17.4	12.2	2.1	2.9	3.2	4.8	-	-	-	49.6
Jenpeg Unit Overhauls	128.1	-	-	-	-	-	-	2.3	2.6	18.6	24.5	25.1	73.1
Power Supply Dam Safety Upgrades	34.0	9.7	1.7	-	-	-	-	-	-	-	-	-	11.4
Winnipeg River Riverbank Protection Program	19.7	1.3	1.2	1.2	1.3	1.3	1.3	1.3	1.5	-	-	-	10.4
Power Supply Hydraulic Controls	16.0	3.1	1.9	1.2	-	-	-	-	-	2.2	2.7	0.7	11.7
Slave Falls Rehabilitation	198.3	13.0	4.0	1.1	16.3	11.8	15.6	54.3	59.4	11.8	-	-	187.3
Great Falls Unit 4 Overhaul	19.7	3.0	7.0	7.8	-	-	-	-	-	-	-	-	17.8
Great Falls 115 kV Indoor Station Safety Improvements	11.6	1.6	-	-	-	-	-	-	-	-	-	-	1.6
Generation South Transformer Refurbish & Spares	21.0	0.0	1.5	3.1	5.3	4.4	2.8	2.7	1.1	-	-	-	20.9
Water Licenses & Renewals	40.8	4.4	6.0	6.0	5.7	5.9	4.9	3.2	-	-	-	-	36.1
Generation South PCB Regulation Compliance	4.7	0.2	0.3	0.1	0.1	0.2	3.8	-	-	-	-	-	4.7
Kettle Transformer Overhaul Program	35.6	1.6	6.6	6.5	6.6	6.8	7.4	-	-	-	-	-	35.4
Generation South Breaker Replacements	9.4	1.6	3.1	2.2	2.0	0.4	-	-	-	-	-	-	9.3
Seven Sisters Upgrades	9.5	1.8	5.3	1.2	1.0	-	-	-	-	-	-	-	9.4
Generation South Excitation Upgrades	18.3	-	2.0	1.0	1.1	1.7	1.4	1.3	1.5	0.6	7.7	-	18.3
Brandon Unit 5 License Review	18.7	0.3	2.5	11.1	-	-	-	-	-	-	-	-	13.9
Selkirk Enhancements	14.2	5.8	5.2	-	-	-	-	-	-	-	-	-	11.0
Laurie River/CRD Communications and Annunciation Upgrades	4.8	0.2	3.5	0.0	1.1	-	-	-	-	-	-	-	4.8
Notigi Marine Vessel Replacement & Infrastructure Improvements	2.6	0.0	1.3	1.3	-	-	-	-	-	-	-	-	2.6
Fire Protection Projects - HVDC	5.2	0.5	0.4	1.6	1.7	-	-	-	-	-	-	-	4.2
Halon Replacement Project	42.5	14.6	13.1	9.1	-	-	-	-	-	-	-	-	36.8
Power Supply Fall Protection Program	13.5	0.2	-	-	-	-	-	-	-	-	-	-	0.2

CAPITAL EXPENDITURE FORECAST SUMMARY TABLE (CEF09)

(in millions of dollars)

	Total Project Cost	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	11 Year Total
Power Supply - continued													
Oil Containment - Power Supply	19.1	0.6	0.4	1.0	0.5	0.3	0.3	0.1	0.9	-	-	-	4.1
Grand Rapids GS Townsite House Renovations	5.2	0.1	0.4	0.9	1.2	1.3	1.3	-	-	-	-	-	5.2
Grand Rapids GS Fish Hatchery	2.2	0.1	1.1	0.9	-	-	-	-	-	-	-	-	2.2
Generation Townsite Infrastructure	52.1	7.8	8.4	5.4	-	-	-	-	-	-	-	-	21.6
Site Remediation of Contaminated Corporate Facilities	34.7	2.3	1.2	1.1	1.1	0.2	-	-	-	-	-	-	5.9
High Voltage Test Facility	26.9	10.6	13.5	-	-	-	-	-	-	-	-	-	24.1
Power Supply Security Installations / Upgrades	43.2	9.7	16.0	8.7	2.1	1.5	1.0	1.0	0.5	-	-	-	40.6
Power Supply Sewer & Domestic Water System Install and Upgrade	15.1	7.3	3.4	0.7	-	-	-	-	-	-	-	-	11.4
Power Supply Domestic	NA	19.1	19.3	19.7	20.1	20.5	20.9	21.4	21.8	22.2	22.7	23.1	230.9
		139.5	161.4	157.2	134.6	116.4	108.9	108.1	96.5	55.5	57.5	48.9	1,184.6
Transmission													
Winnipeg - Brandon Transmission System Improvements	40.0	3.1	1.6	3.4	3.6	5.0	21.7	-	-	-	-	-	38.4
Transcona East 230-66 kV Station	31.0	1.1	11.0	13.2	5.1	-	-	-	-	-	-	-	30.5
Neepawa 230 - 66 kV Station	30.0	1.1	14.1	9.5	5.1	-	-	-	-	-	-	-	29.9
Pine Falls - Bloodvein 115 kV Transmission Line	34.1	-	0.3	0.9	4.4	20.6	7.8	-	-	-	-	-	34.1
Transmission Line Re-Rating	24.1	3.2	-	-	-	-	-	-	-	-	-	-	3.2
St Vital-Steinbach 230 kV Transmission	32.2	-	-	-	-	-	-	0.8	0.9	2.6	6.0	9.6	20.0
Rosser Station 230 - 115 kV Bank 3 Replacement	5.8	2.6	-	-	-	-	-	-	-	-	-	-	2.6
Rosser - Inkster 115 kV Transmission	5.1	3.3	1.4	-	-	-	-	-	-	-	-	-	4.7
Transcona Station 66 kV Breaker Replacement	6.0	0.0	3.6	1.8	0.6	-	-	-	-	-	-	-	6.0
Transcona & Ridgeway Stations 66 kV Bus Upgrades	2.8	1.7	0.7	-	-	-	-	-	-	-	-	-	2.4
Dorsey 500 kV R502 Breaker Replacement	2.6	2.3	0.2	-	-	-	-	-	-	-	-	-	2.6
13.2kV Shunt Reactor Replacements	33.0	0.0	0.0	4.1	4.2	4.3	4.4	4.4	4.5	4.6	2.5	-	33.0
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	-	-	-	1.8	8.1	7.6	3.5	-	-	-	-	21.1
Stanley Station 230-66 kV Hot Standby Installation	6.2	4.9	1.2	-	-	-	-	-	-	-	-	-	6.1
Ashern Station 230 kV Shunt Reactor Replacement	2.7	0.0	0.0	-	2.7	-	-	-	-	-	-	-	2.7
Tadoule Lake DGS Tank Farm Upgrade	1.1	0.5	0.5	0.0	-	-	-	-	-	-	-	-	1.0
Interlake Digital Microwave Replacement	19.7	3.5	0.4	-	-	-	-	-	-	-	-	-	3.8
Communication System - Southern MB (Great Plains)	21.9	2.4	-	-	-	-	-	-	-	-	-	-	2.4
Communications Upgrade Winnipeg Area	7.4	0.7	-	-	-	-	-	-	-	-	-	-	0.7
Pilot Wire Replacement	9.6	1.3	1.4	-	-	-	-	-	-	-	-	-	2.7
Transmission Line Protection & Teleprotection Replacement	21.1	1.4	6.1	6.1	2.3	1.1	0.9	-	-	-	-	-	17.9
Winnipeg Central Protection Wireline Replacement	9.3	2.5	0.6	-	-	-	-	-	-	-	-	-	3.1
Mobile Radio System Modernization	30.7	0.3	2.5	9.2	10.6	8.0	-	-	-	-	-	-	30.6
Cyber Security Systems	10.1	3.6	0.4	-	-	-	-	-	-	-	-	-	4.0
Site Remediation	13.3	1.3	3.8	1.1	-	-	-	-	-	-	-	-	6.2
Oil Containment	7.4	0.9	0.5	-	-	-	-	-	-	-	-	-	1.4
Station Battery Bank Capacity & System Reliability Increase	46.5	5.3	4.7	6.4	6.4	6.6	6.3	-	-	-	-	-	35.7
Red River Floodway Expansion Project	1.8	0.3	-	-	-	-	-	-	-	-	-	-	0.3
Waverley Service Centre Oil Tank Farm Replacement	3.0	0.5	1.0	0.6	0.4	0.5	-	-	-	-	-	-	3.0
Transmission Domestic	NA	29.6	30.0	30.6	31.2	31.8	32.4	33.1	33.8	34.4	35.1	35.8	357.7
		77.5	86.0	86.9	78.3	86.2	81.4	46.4	39.2	41.6	43.6	45.4	712.6

CAPITAL EXPENDITURE FORECAST SUMMARY TABLE (CEF09)

(in millions of dollars)

	Total Project Cost	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	11 Year Total
Customer Service & Distribution													
Winnipeg Distribution Infrastructure Requirements	14.9	1.7	-	-	-	-	-	-	-	-	-	-	1.7
Defective RINJ Cable Replacement	8.7	0.5	2.6	-	-	-	-	-	-	-	-	-	3.1
Brereton Lake Station Area	9.0	0.3	-	-	-	-	-	-	-	-	-	-	0.3
Stony Mountain New 115 - 12 kV Station	5.0	0.7	-	-	-	-	-	-	-	-	-	-	0.7
Rover Substation Replace 4 kV Switchgear	12.7	0.4	3.3	3.9	-	-	-	-	-	-	-	-	7.5
Martin New Outdoor Station	28.2	1.0	14.5	9.1	2.4	-	-	-	-	-	-	-	27.0
Frobisher Station Upgrade	14.4	4.4	0.0	-	-	-	-	-	-	-	-	-	4.5
Burrows New 66 kV-12 kV Station	28.6	9.1	12.2	5.0	-	-	-	-	-	-	-	-	26.3
Winnipeg Central District Oil Switch Project	7.1	1.8	-	-	-	-	-	-	-	-	-	-	1.8
William New 66 kV-12 kV Station	10.3	0.5	3.6	3.1	2.9	-	-	-	-	-	-	-	10.0
Waverley West Sub Division Supply - Stage 1	6.5	4.4	-	-	-	-	-	-	-	-	-	-	4.4
St. James 24 kV System Refurbishment	65.9	1.3	14.1	31.6	18.9	-	-	-	-	-	-	-	65.8
Shoal Lake New 33 - 12.47 kV DSC	3.6	3.2	-	-	-	-	-	-	-	-	-	-	3.2
York Station	4.0	2.0	1.8	0.1	-	-	-	-	-	-	-	-	3.9
Cromer North Station & Reston RE12-4 25 kV Conversion	4.3	3.0	0.1	1.2	-	-	-	-	-	-	-	-	4.3
Brandon Crocus Plains 115 - 25 kV Bank Addition	6.3	0.6	3.1	1.9	0.6	-	-	-	-	-	-	-	6.2
Winkler Market Feeder M25-13 Conversion	2.9	0.8	-	-	-	-	-	-	-	-	-	-	0.8
Neepawa North Feeder NN12-2 & Line 57 Rebuild	1.9	1.9	-	-	-	-	-	-	-	-	-	-	1.9
Perimeter South Station Distribution Supply Centre Installation	2.4	0.4	2.0	-	-	-	-	-	-	-	-	-	2.4
Niverville Station 66-12 kV Bank Replacements	2.6	2.6	-	-	-	-	-	-	-	-	-	-	2.6
Winnipeg Central District Underground Network Asbestos Removal	3.0	0.7	-	-	-	-	-	-	-	-	-	-	0.7
Gas SCADA Replacement	4.6	1.0	3.0	0.6	-	-	-	-	-	-	-	-	4.6
Customer Service & Distribution Domestic	NA	115.9	117.5	119.9	122.3	124.7	127.2	129.8	132.4	135.0	137.7	140.5	1,402.9
		158.1	177.8	176.3	147.0	124.7	127.2	129.8	132.4	135.0	137.7	140.5	1,586.4
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	2.5	2.6	2.6	2.7	2.7	2.8	2.8	2.9	2.9	3.0	3.1	30.6
		2.5	6.5	8.0	8.1	8.3	7.1	7.1	2.9	2.9	3.0	3.1	59.5

CAPITAL EXPENDITURE FORECAST SUMMARY TABLE (CEF09)
(in millions of dollars)

	Total Project Cost	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	11 Year Total
Finance & Administration													
Corporate Buildings	NA	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	88.0
Workforce Management (Phase 1 to 4)	11.3	3.9	1.0	-	-	-	-	-	-	-	-	-	4.9
Fleet	NA	13.3	13.5	13.8	14.1	14.3	14.6	14.9	15.2	15.5	15.8	16.2	161.2
Finance & Administration Domestic	NA	24.1	24.4	24.9	25.4	25.9	26.4	27.0	27.5	28.1	28.6	29.2	291.6
		49.2	46.9	46.7	47.5	48.3	49.1	49.9	50.7	51.6	52.5	53.3	545.7
Capital Increase Provision		-	-	-	-	-	-	63.1	90.4	82.8	97.3	99.2	432.8
ELECTRIC CAPITAL SUBTOTAL		**1,255.0**	**1,165.5**	**1,074.5**	**1,038.6**	**1,228.0**	**1,691.7**	**2,247.6**	**2,160.5**	**1,653.3**	**1,800.3**	**1,557.9**	**16,872.9**
GAS													
Customer Service & Distribution													
Customer Service & Distribution Domestic - Gas	NA	20.7	21.2	21.7	22.1	22.5	23.0	23.4	23.9	24.4	24.9	25.4	253.3
		20.7	21.2	21.7	22.1	22.5	23.0	23.4	23.9	24.4	24.9	25.4	253.3
Customer Care & Marketing													
Advanced Metering Infrastructure - Gas	15.0	-	1.0	5.4	8.3	-	-	-	-	-	-	-	14.6
Demand Side Management - Gas	NA	13.5	13.1	11.6	11.7	11.1	10.2	10.6	10.3	7.7	5.5	5.1	110.3
Customer Care & Marketing Domestic - Gas	NA	2.8	2.8	2.9	2.9	3.0	3.0	3.1	3.2	3.2	3.3	3.4	33.5
		16.2	16.9	19.8	22.9	14.1	13.2	13.7	13.5	11.0	8.8	8.4	158.5
Capital Increase Provision		-	-	-	-	-	-	-	-	2.3	4.9	5.0	12.1
GAS CAPITAL SUBTOTAL		**37.0**	**38.2**	**41.5**	**45.0**	**36.6**	**36.2**	**37.2**	**37.4**	**37.6**	**38.5**	**38.8**	**423.9**
CONSOLIDATED CAPITAL		**1,292.0**	**1,203.6**	**1,116.0**	**1,083.6**	**1,264.6**	**1,727.9**	**2,284.8**	**2,197.9**	**1,690.9**	**1,838.8**	**1,596.6**	**17,296.7**
TARGET ADJUSTMENT		(188.0)	(118.6)	(80.0)	(59.1)	221.4	37.1	(128.8)	(32.7)	25.4	(187.8)	(305.6)	(816.7)
		1,104.0	**1,085.0**	**1,036.0**	**1,024.5**	**1,486.0**	**1,765.0**	**2,156.0**	**2,165.2**	**1,716.3**	**1,651.0**	**1,291.0**	**16,480.0**

12.0 ELECTRIC OPERATIONS INTEGRATED FINANCIAL FORECAST (MH09-1)

ELECTRIC OPERATIONS (MH09-1)
PROJECTED OPERATING STATEMENT
(In Millions of Dollars)

For the year ended March 31	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
REVENUES											
General Consumers											
at approved rates	1,160	1,159	1,177	1,191	1,204	1,229	1,244	1,260	1,272	1,283	1,297
additional *	-	33	69	113	161	212	266	322	381	442	508
Extraprovincial	414	383	554	583	615	590	701	729	742	894	1,093
Other	7	7	8	8	8	8	8	9	9	9	9
	1,581	1,584	1,808	1,895	1,987	2,039	2,219	2,320	2,404	2,628	2,907
EXPENSES											
Operating and Administrative	372	380	403	411	420	428	437	445	467	478	497
Finance Expense	417	413	468	525	527	544	529	545	587	674	878
Depreciation and Amortization	368	386	407	435	446	466	476	481	501	532	566
Water Rentals and Assessments	120	110	111	113	114	114	115	115	115	115	124
Fuel and Power Purchased	103	132	248	250	260	269	297	341	363	441	419
Capital and Other Taxes	73	76	77	80	85	92	100	109	115	121	124
Corporate Allocation	8	9	9	9	9	9	9	9	9	9	9
	1,460	1,505	1,723	1,824	1,860	1,922	1,963	2,046	2,156	2,370	2,617
Non-controlling Interest	-	-	1	1	(2)	(5)	(9)	(11)	(12)	(15)	(14)
Net Income	121	78	87	72	125	113	248	263	235	244	276
*Additional General Consumers Revenue											
Percent Increase		2.90%	2.90%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%
Cumulative Percent Increase		2.90%	5.88%	9.59%	13.43%	17.40%	21.50%	25.76%	30.16%	34.71%	39.43%

ELECTRIC OPERATIONS (MH09-1)
PROJECTED BALANCE SHEET
(In Millions of Dollars)

For the year ended March 31	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
ASSETS											
Plant in Service	12,527	13,034	15,075	15,566	15,982	16,691	17,127	17,837	20,301	21,599	25,001
Accumulated Depreciation	(4,663)	(5,018)	(5,398)	(5,805)	(6,216)	(6,649)	(7,091)	(7,540)	(8,010)	(8,514)	(9,052)
Net Plant in Service	7,865	8,015	9,677	9,761	9,765	10,042	10,035	10,297	12,292	13,085	15,950
Construction in Progress	1,947	2,458	1,341	1,818	2,838	3,854	5,532	6,948	6,159	6,446	4,168
Current and Other Assets	2,767	2,735	2,871	2,926	2,708	2,860	3,047	3,259	3,564	3,348	3,683
Goodwill	42	42	42	42	42	42	42	42	42	42	42
	12,621	13,251	13,931	14,546	15,353	16,798	18,656	20,545	22,057	22,922	23,843
LIABILITIES AND EQUITY											
Long-Term Debt	7,800	8,596	9,054	8,769	10,349	11,505	13,123	14,412	15,346	16,429	14,147
Current and Other Liabilities	2,156	1,926	2,119	2,916	2,106	2,306	2,333	2,692	3,045	2,586	5,514
Contributions in Aid of Construction	290	288	284	280	276	275	274	273	272	271	271
Retained Earnings	2,183	2,261	2,331	2,403	2,528	2,641	2,889	3,153	3,388	3,632	3,908
Accumulated Other Comprehensive Income	192	178	143	178	94	71	38	17	6	3	3
	12,621	13,251	13,931	14,546	15,353	16,798	18,656	20,545	22,057	22,922	23,843

ELECTRIC OPERATIONS (MH09-1)
PROJECTED CASH FLOW STATEMENT
(In Millions of Dollars)

For the year ended March 31	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
OPERATING ACTIVITIES											
Cash Receipts from Customers	1,581	1,584	1,808	1,895	1,987	2,039	2,219	2,320	2,404	2,628	2,907
Cash Paid to Suppliers and Employees	(646)	(690)	(827)	(845)	(872)	(898)	(946)	(1,010)	(1,059)	(1,156)	(1,168)
Interest Paid	(453)	(423)	(479)	(541)	(550)	(549)	(554)	(566)	(634)	(725)	(915)
Interest Received	29	22	14	16	14	4	15	26	36	39	33
	511	493	516	524	579	596	734	769	746	786	859
FINANCING ACTIVITIES											
Proceeds from Long-Term Debt	745	800	600	540	1,600	1,400	1,800	1,800	1,800	1,400	1,000
Sinking Fund Withdrawals	262	227	27	103	483	-	3	-	-	456	171
Retirement of Long-Term Debt	(355)	(304)	(27)	(121)	(849)	(100)	(262)	(201)	(530)	(869)	(321)
Other	(35)	(10)	19	(10)	(14)	(12)	(13)	(14)	(15)	(26)	(15)
	618	713	619	512	1,220	1,288	1,528	1,585	1,255	961	835
INVESTING ACTIVITIES											
Property, Plant and Equipment, net of contribution	(1,113)	(1,079)	(1,004)	(989)	(1,457)	(1,737)	(2,125)	(2,135)	(1,685)	(1,619)	(1,259)
Sinking Fund Payment	(94)	(99)	(98)	(116)	(176)	(107)	(201)	(159)	(242)	(200)	(256)
Other	(36)	(20)	(16)	(17)	(15)	(31)	(29)	(40)	(28)	(27)	(27)
	(1,243)	(1,198)	(1,118)	(1,123)	(1,648)	(1,876)	(2,355)	(2,334)	(1,954)	(1,846)	(1,543)
Net Increase (Decrease) in Cash	(114)	8	17	(86)	151	9	(92)	21	47	(98)	151
Cash at Beginning of Year	66	(48)	(40)	(23)	(109)	41	51	(41)	(21)	26	(72)
Cash at End of Year	(48)	(40)	(23)	(109)	41	51	(41)	(21)	26	(72)	79

ELECTRIC OPERATIONS
COMPARISON OF MH09-1 To MH08-1
INCREASE / (DECREASE)
(In Millions of Dollars)

ACCOUNT	2010	CUMULATIVE 2010-2012	CUMULATIVE 2010-2019	VARIANCE EXPLANATION
REVENUES				
General Consumers Revenue including Projected Rate Increases	(44)	(212)	(530)	2.9% April 1, 2009 compared to 4.0% in previous forecast and 3.5% annually 2013 to 2020 compared to 2.9%. Lower load growth in industrial sectors throughout forecast due to economic downturn partially offset by higher load growth in residential sector. Delay in implementation of energy intensive industrial rate structure combined with lower industrial sector consumption.
Extraprovincial	(131)	(135)	465	Lower market prices in 2010 & 2011. Higher surplus energy for export resulting from lower Manitoba demand and weakening of the Canadian dollar for the balance of the forecast compared to the previous forecast.
Other	(0)	(0)	2	
Total Revenue	**(175)**	**(346)**	**(63)**	
EXPENSES				
Operating and Administrative	13	52	238	MH09-1 reclassified IFRS provision to OM&A. Higher facility operating & maintenance costs.
Finance Expense	(3)	(21)	59	Higher finance expense over the forecast period is due to lower net income and a weaker Canadian dollar. This increase is partially offset by lower interest rates and a change in scope on the Pointe du Bois project.
Depreciation and Amortization	(4)	(30)	(194)	MH09-1 reclassified IFRS provision to OM&A. Higher depreciation due to reduction in IFRS related write-offs compared to last year's forecast, increased Bill 11 expenditures partially offset by higher customer contributions and a change in scope on the Pointe du Bois project.
Water Rentals and Assessments	8	11	4	Increased hydraulic generation due to above normal rainfall and carry-over storage in early years.
Fuel and Power Purchased	(95)	(128)	249	Increased hydraulic generation and lower market prices in early years. Higher purchases over forecast due primarily to additional 300MW wind purchase beginning 2011 and a weaker Canadian dollar partially offset by reduced import and thermal requirements due to restriction on Brandon 5.
Capital and Other Taxes	2	7	34	Reclassification of funding agreements from OM&A partially offset by lower grants in lieu of taxes
Corporate Allocation	0	2	9	
Total Expenses	**(79)**	**(106)**	**398**	
Non-controlling Interest	-	(1)	(19)	Lower interest rates.
Change in Net Income	**(97)**	**(241)**	**(480)**	

13.0 GAS OPERATIONS INTEGRATED FINANCIAL FORECAST (CGM09-1)

GAS OPERATIONS (CGM09-1)
PROJECTED OPERATING STATEMENT
(In Millions of Dollars)

For the year ended March 31	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
REVENUES											
General Consumers											
at approved rates	493	478	487	496	493	500	501	502	503	503	503
additional revenue requirement *	0	0	7	8	13	13	18	18	23	29	29
	493	478	494	504	506	512	519	520	526	532	531
Cost of Gas Sold	352	332	340	346	343	349	350	351	352	353	352
Gross Margin	141	146	154	158	163	163	168	168	174	179	179
Other	2	2	2	2	2	2	2	2	2	2	2
	142	148	155	159	165	165	170	170	176	181	181
EXPENSES											
Operating and Administrative	60	61	63	64	65	66	68	69	70	72	73
Finance Expense	19	20	23	25	25	25	26	26	26	27	27
Depreciation and Amortization	24	26	28	31	32	34	35	36	37	39	39
Capital and Other Taxes	23	23	23	24	24	24	24	24	25	25	25
Corporate Allocation	12	12	12	12	12	12	12	12	12	12	12
	139	143	149	154	158	161	164	168	171	174	177
Net Income	4	5	6	5	7	3	6	2	5	7	4
*Additional Revenue Requirement											
Percent Increase		0.00%	1.50%	0.00%	1.00%	0.00%	1.00%	0.00%	1.00%	1.00%	0.00%
Cumulative Percent Increase		0.00%	1.50%	1.50%	2.52%	2.52%	3.54%	3.54%	4.58%	5.62%	5.62%

GAS OPERATIONS (CGM09-1)
PROJECTED BALANCE SHEET
(In Millions of Dollars)

For the year ended March 31	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
ASSETS											
Plant in Service	624	645	666	695	717	740	757	780	806	836	866
Accumulated Depreciation	(224)	(237)	(246)	(260)	(275)	(290)	(301)	(316)	(333)	(351)	(369)
Net Plant in Service	400	408	420	436	443	450	456	464	473	485	497
Construction in Progress	2	2	2	2	2	2	2	2	2	2	2
Current and Other Assets	237	246	249	250	251	249	249	246	242	234	226
	639	656	671	688	695	701	707	712	717	721	725
LIABILITIES AND EQUITY											
Long-Term Debt	297	297	235	295	295	295	295	295	295	295	295
Current and Other Liabilities	149	161	234	186	184	187	188	191	192	190	191
Contributions in Aid of Construction	32	31	30	29	32	32	31	30	30	29	28
Share Capital	121	121	121	121	121	121	121	121	121	121	121
Retained Earnings	40	45	51	56	63	66	72	74	79	86	90
	639	656	671	688	695	701	707	712	717	721	725

GAS OPERATIONS (CGM09-1)
PROJECTED CASH FLOW STATEMENT
(In Millions of Dollars)

For the year ended March 31	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
OPERATING ACTIVITIES											
Cash Receipts from Customers	571	556	571	578	580	587	593	595	601	607	606
Cash Paid to Suppliers and Employees	(514)	(522)	(520)	(520)	(525)	(526)	(529)	(532)	(535)	(538)	(539)
Interest Paid	(21)	(22)	(25)	(27)	(27)	(28)	(28)	(28)	(28)	(28)	(28)
Interest Received	-	-	-	-	-	-	-	-	-	-	-
	35	12	26	31	28	33	37	34	37	41	39
FINANCING ACTIVITIES											
Proceeds from Long-Term Debt	155	-	-	60	-	-	-	-	-	-	-
Retirement of Long-Term Debt	(93)	-	-	(63)	-	-	-	-	-	-	-
Other	(2)	(1)	0	0	0	0	0	0	0	0	0
	60	(1)	0	(2)	0	0	0	0	0	0	0
INVESTING ACTIVITIES											
Property, Plant and Equipment, net of contribution	(38)	(39)	(42)	(45)	(37)	(37)	(38)	(38)	(38)	(39)	(40)
Other	-	-	-	-	(1)	(0)	(0)	(0)	(0)	(0)	(0)
	(38)	(39)	(42)	(45)	(39)	(37)	(38)	(38)	(38)	(39)	(40)
Net Increase (Decrease) in Cash	58	(28)	(16)	(17)	(10)	(3)	(1)	(4)	(1)	2	(1)
Cash at Beginning of Year	(102)	(45)	(73)	(89)	(106)	(116)	(119)	(120)	(123)	(124)	(122)
Cash at End of Year*	(45)	(73)	(89)	(106)	(116)	(119)	(120)	(123)	(124)	(122)	(123)

** Centra's cash requirements are managed on a consolidated basis with short-term funds advanced from the parent. Accordingly, this balance is presented in the Financing Activities section of the annual audited Statement of Cash Flows for Centra Gas Manitoba Inc as short-term advances from parent.*

GAS OPERATIONS
COMPARISON OF CGM09-1 TO CGM08-1
INCREASE / (DECREASE)
(In millions of Dollars)

ACCOUNT	2010	CUMULATIVE 2010-2012	CUMULATIVE 2010-2019	VARIANCE EXPLANATION
REVENUES				
General Consumers Revenue at approved rates	(101)	(348)	(1,059)	Lower primarily due to decreased gas prices and increased funding for the Furnace Replacement Program of $3.8 million annually from 2010-2012 per PUB order 128/09.
Projected Rate Increases	(6)	(30)	(106)	Lower primarily due to no rate increases in 2010 and 2011 resulting from PUB order 128/09. Slightly offset by a change in the 2012 rate increase from 1.00% to 1.50%.
Cost of Gas Sold	(99)	(354)	(1,116)	Lower primarily due to decreased gas prices.
Other	(0)	(1)	(4)	Lower primarily due to decreased late penalty charges as a result of the consolidation of customers' gas and electric bills.
Total Revenue	**(8)**	**(25)**	**(52)**	
EXPENSES				
Operating and Administrative	1	3	11	Higher due to provisions for increased expenditures.
Finance Expense	(6)	(14)	(14)	Lower primarily due to decreases in the projected interest rates. Partially offset by higher short-term debt requirements.
Depreciation and Amortization	(4)	(17)	(35)	Lower primarily due to decreased Demand Side Management expenditures and in increase in their amortization period from five to ten years.
Capital and Other Taxes	(0)	(2)	(9)	Lower primarily due to a decrease in property taxes anticipated from the 2010 Provincial Reassessment.
Total Expenses	**(9)**	**(31)**	**(47)**	
Change in Net Income	**1**	**5**	**(6)**	

14.0 ELECTRIC SUBSIDIARIES INTEGRATED FINANCIAL FORECAST (ES09-1)

ELECTRIC SUBSIDIARIES (ES09-1)
PROJECTED OPERATING STATEMENT
(In Millions of Dollars)

For the year ended March 31	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
REVENUES											
General Consumers											
at approved rates											
additional *											
Extraprovincial											
Other	19	20	22	22	23	23	24	24	25	25	26
	19	20	22	22	23	23	24	24	25	25	26
EXPENSES											
Operating and Administrative	14	15	16	16	17	17	17	18	18	18	19
Finance Expense	0	0	0	0	0	0	0	0	0	0	0
Depreciation and Amortization	0	0	0	0	0	0	0	0	0	0	0
Water Rentals and Assessments	0	0	0	0	0	0	0	0	0	0	0
Fuel and Power Purchased											
Capital and Other Taxes	0	0	0	0	0	0	0	0	0	0	0
	15	16	17	17	17	18	18	18	18	19	19
Non-controlling Interest	0	0	0	0	0	0	0	0	0	0	0
Net Income (Loss)	4	5	5	5	5	5	6	6	6	6	6