20 YEAR FINANCIAL OUTLOOK

- Updated to reflect the revised capital estimate for Bipole III

2010/11 – 2029/30

FINANCIAL PLANNING
CONTROLLER DIVISION
FINANCE & ADMINISTRATION

June 2011
(OL10-2)

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20 YEAR FINANCIAL OUTLOOK (OL10-2)

1.0 OVERVIEW

The May 2011 20 Year Financial Outlook is an update to the March 2011 20 Year Financial Outlook to reflect revisions to the capital estimate for Bipole III. The projected cost of Bipole III has increased from the previous estimate of $2.248 billion to $3.280 billion. All other assumptions remain the same as the March 20 Year Financial Outlook.

The $1.032 billion increase to the capital estimate for Bipole III has the following impacts on the May 20 Year Financial Outlook (compared to the March 20 Year Financial Outlook):

1) Long term debt increases by $1.8 billion by year 2029/30 as a result of increased borrowing requirements and related financing costs.

2) Commencing in 2017/18 (the projected in-service date for Bipole III) net income is projected to be lower than the previous forecast but remains positive throughout the forecast period.

3) Maintaining the same domestic rate increases as in the previous Outlook, retained earnings decrease by $1.7 billion but still reach $8.8 billion by 2029/30.

4) The debt/equity ratio is projected to be 84:16 by 2020/21. Thereafter, the debt/equity recovers strongly and is projected to reach the target of 75:25 in 2027/28.

2.0 KEY ASSUMPTIONS

The key assumptions included in the updated 20 Year Financial Outlook are identical to the previous Outlook except for the increased estimate for Bipole III. The key assumptions are as follows:

1) Domestic Load Growth

   Domestic electricity load is projected to grow at an average of 1.5% per year for net firm energy and at an average of 1.4% per year for net peak demand over the 20 period to 2029/30.

   Natural gas volumes are projected to decline approximately 0.4% per year over the 20 year period to 2029/30.

2) Domestic Rate Increases

   The interim approved average electricity rate increase of 2.8% is included in 2010/11 and an additional 2.9% average rate increase is projected in 2011/12 followed by 3.5% per year to 2020/21. Projected average electricity rate increases then decline to 2% per year for the last 9 years of the 20 Year Financial Outlook.

   Natural gas rate increases are projected to be only the rates necessary to generate net income of approximately $3 to $6 million per year (rate increases average less than 1% per year).

3) Inflation

   The Manitoba Consumers Price Index is projected to increase at an average 2.1% per year commencing in 2013/14.

4) Interest Rates

   The very low current short and long-term interest rates are projected to rise gradually over the next several years with long-term rates reaching 6.60% by 2016/17 (excluding the debt guarantee fee of 1.0%) and then remain constant to 2029/30.

5) Foreign Exchange Rates

   The US-Canadian exchange rate is projected to rise to 1.04 by 2012/13, 1.09 by 2014/15 and 1.11 by 2015/16 through to the end of the 20 year forecast.

6) Export Sales Contracts

   The 10 year Northern States Power sale agreements of 375MW to 500MW (commencing in 2015) were signed in 2010. The term sheets for the 500 MW Wisconsin Public Service sale and the 250 MW Minnesota Power sale are expected to be finalized into long-term contracts.

7) Capital Expenditures

   Investments in new property, plant and equipment are projected to be $18.0 billion during the first decade with major expenditures on Wuskwatim, Keeyask, a new US interconnection, Conawapa and Bipole 3. The second decade includes the construction of Conawapa with a first unit in-service of 2023/24 plus additional transmission from northern Manitoba to Winnipeg. The latter part of the 20 Year Financial Outlook also includes the proposed redevelopment of the Pointe du Bois Generating Station at a higher capability by 2030/31.

Figure 1 illustrates projected capital expenditures by major categories including major new generation & transmission, gas and other electric capital requirements including system refurbishment and upgrades.

Figure 2 summarizes the major new generation and transmission projects included in the 20 Year Financial Outlook.

Figure 1

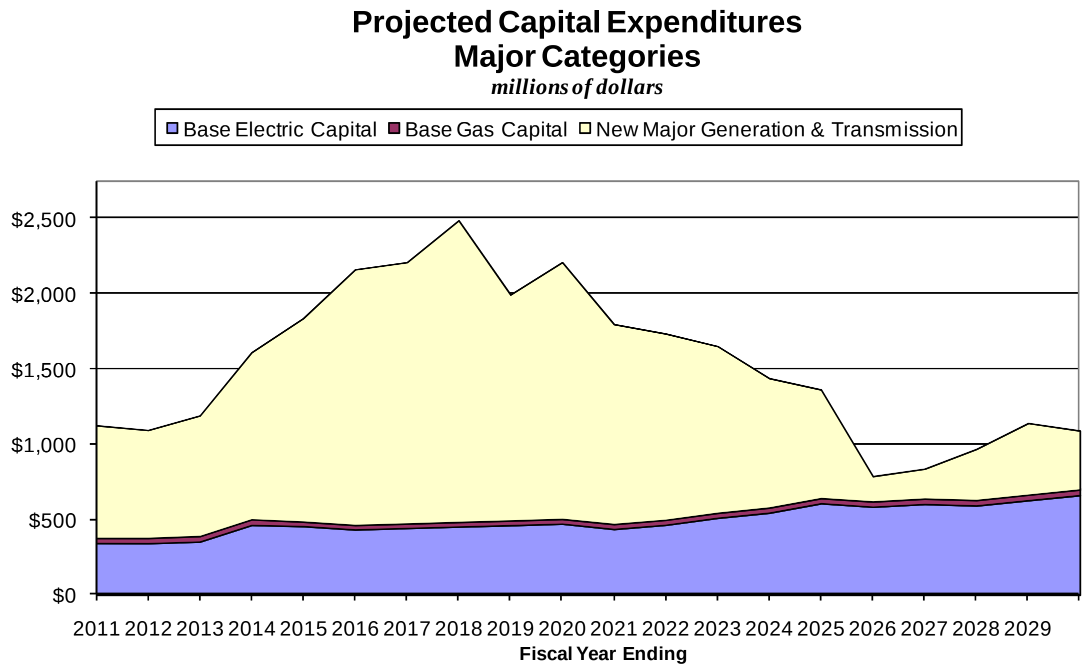


Figure 2
Major New Generation & Transmission

Project	Projected In-Service	Projected Capital Cost ($millions)
Wuskwatim	2011/12	$ 1,565.8
Pointe du Bois Spillway	2014/15	398.2
Bipole III Transmission	2017/18	1,259.9
Bipole III Converter Stations	2017/18	1,828.5
Bipole III Collector Lines	2017/19	191.4
Keeyask	2019/20	5,636.9
500 kV US Interconnection	2019/20	204.8
Conawapa	2023/24	7,770.8
Additional North-South Transmission	2024/25	312.8
Pointe du Bois Powerhouse Rebuild	2030/31	1,538.3

3.0 NET INCOME AND FINANCIAL TARGETS

Projected consolidated net income, equity ratios, interest coverage ratios, and capital coverage ratios for the 20 Year Financial Outlook are depicted in Table 1 and Figures 3 to 6.

Table 1
20 YEAR FINANCIAL OUTLOOK

				RATIOS		
Year Ending March 31	**EXPORT REVENUES**	**NET INCOME** *(Millions)*	**RETAINED EARNINGS** *(Millions)*	**Debt/Equity**	**Interest Coverage**	**Capital Coverage**
2010 (actual)	427	163	2,239	73 : 27	1.32	1.30
2011	444	158	2,398	74 : 26	1.28	1.50
2012	461	134	2,532	74 : 26	1.22	1.49
2013	499	132	2,660	77 : 23	1.20	1.55
2014	510	198	2,858	78 : 22	1.29	1.30
2015	529	155	3,013	79 : 21	1.20	1.35
2016	611	230	3,242	81 : 19	1.26	1.61
2017	621	278	3,521	81 : 19	1.28	1.73
2018	646	227	3,748	82 : 18	1.21	1.64
2019	654	120	3,868	83 : 17	1.10	1.48
2020	804	198	4,066	83 : 17	1.15	1.66
2021	984	12	4,078	84 : 16	1.01	1.51
2022	1,128	244	4,322	83 : 17	1.17	1.91
2023	1,162	332	4,655	83 : 17	1.22	1.93
2024	1,311	392	5,047	82 : 18	1.25	1.98
2025	1,668	504	5,551	80 : 20	1.32	2.07
2026	1,782	462	6,013	79 : 21	1.29	2.16
2027	1,808	552	6,565	77 : 23	1.35	2.28
2028	1,813	648	7,213	74 : 26	1.42	2.48
2029	1,834	753	7,966	72 : 28	1.50	2.53
2030	1,847	864	8,830	69 : 31	1.59	2.58

Note: Assumes 2.8% interim approved average rate increase April 1, 2010; 2.9% proposed average rate increase April 1, 2011; 3.5% projected average annual rate increases from 2013 to 2021; and 2.0% from 2022 to 2030.

Figure 3

Projected Consolidated Net Income

millions of dollars

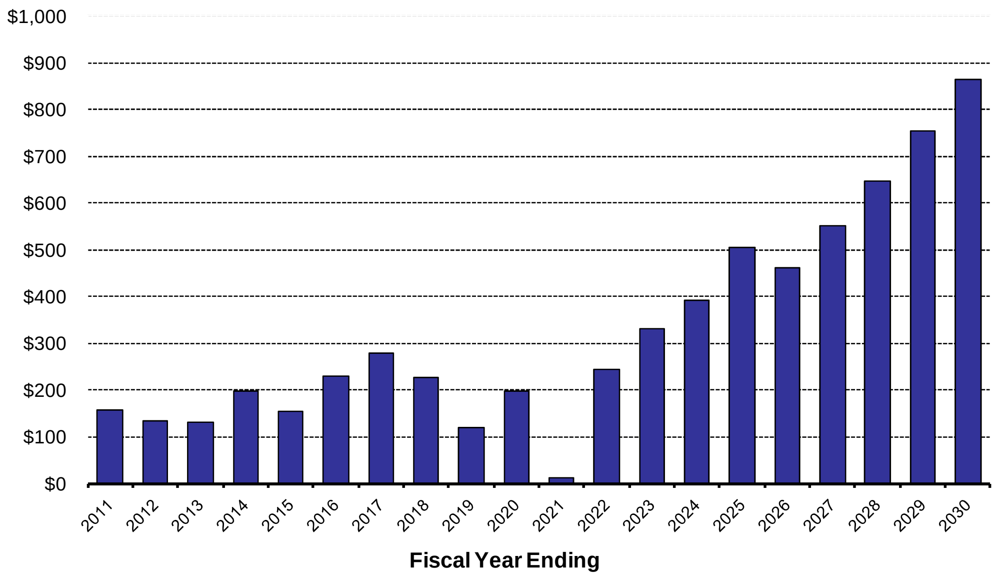


Figure 4

Projected Consolidated Equity Ratio

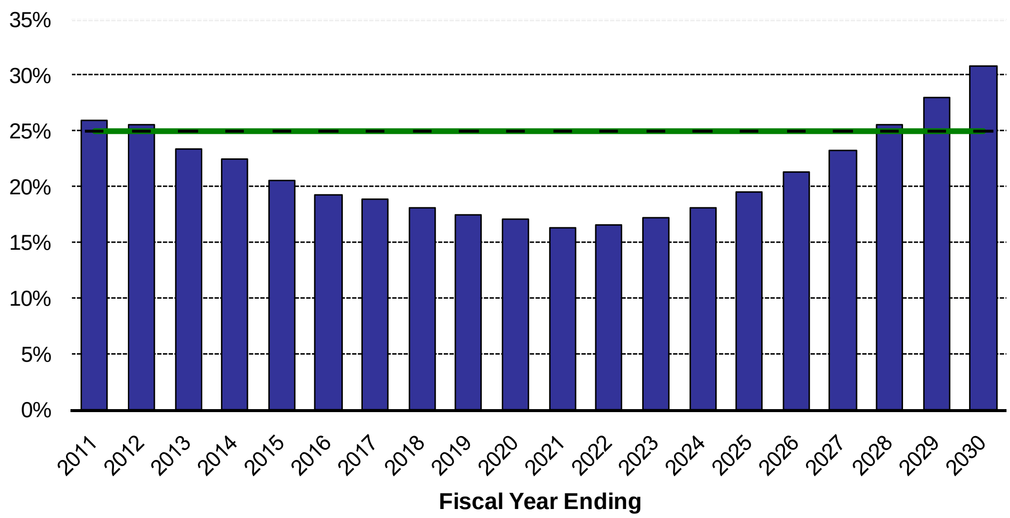


Figure 5

Projected Consolidated Interest Coverage Ratio

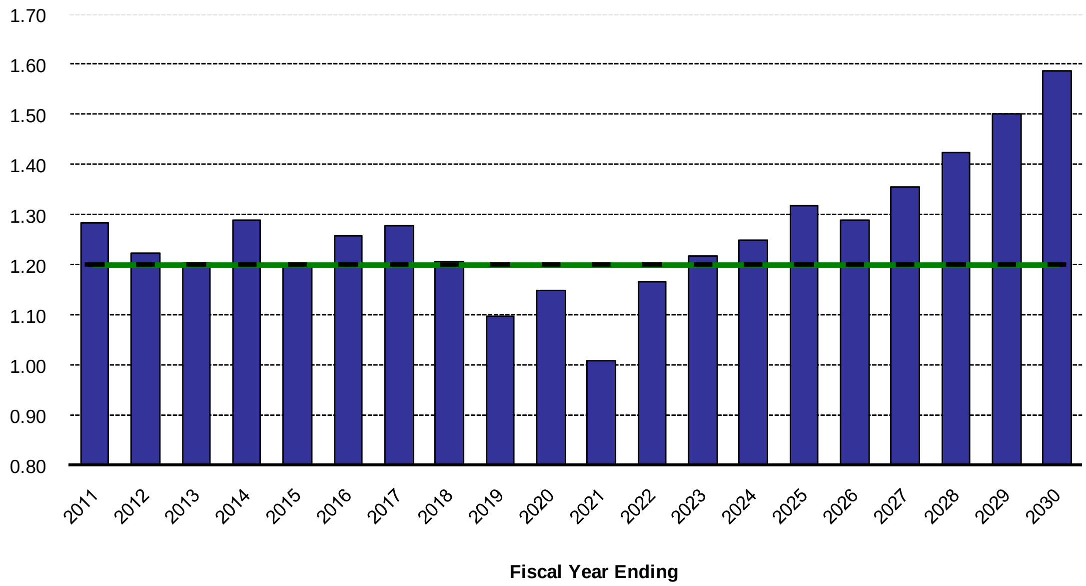
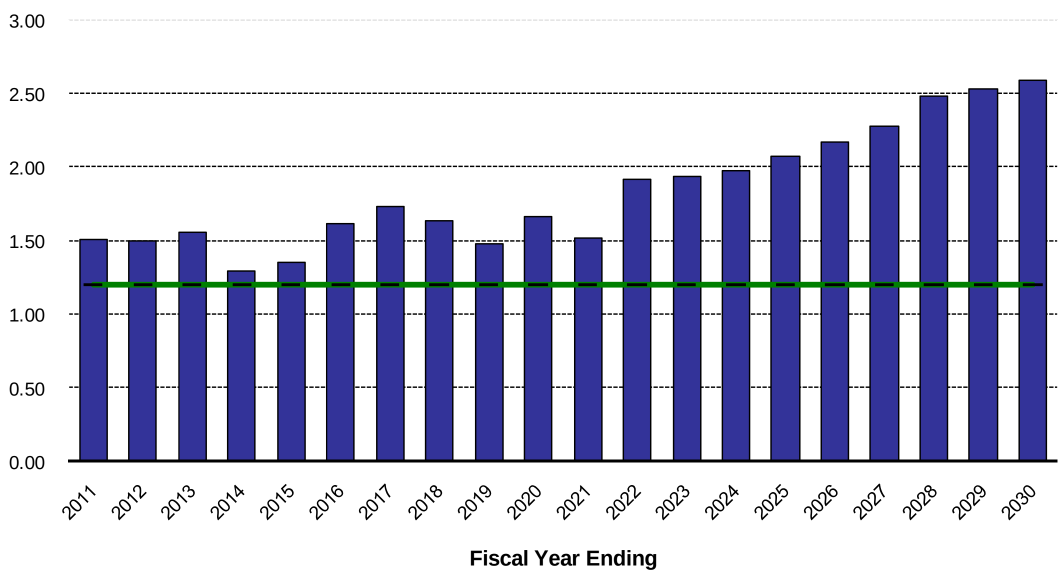


Figure 6

Projected Consolidated Capital Coverage Ratio



4.0 PROJECTED CONSOLIDATED FINANCIAL STATEMENTS

CONSOLIDATED 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	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	448	510	492	557	582	577	644	764	825
Depreciation and Amortization	403	435	464	468	495	517	524	555	596	610
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	107	113	121	130	139	150	157	166
	1,650	1,770	1,878	1,893	2,017	2,091	2,128	2,271	2,463	2,619
Non-controlling Interest	-	4	6	4	0	(4)	(7)	(9)	(12)	(15)
Net Income	158	134	132	198	155	230	278	227	120	198
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%	23%	22%	21%	19%	19%	18%	17%	17%
Interest Coverage	1.28	1.22	1.20	1.29	1.20	1.26	1.28	1.21	1.10	1.15
Capital Coverage	1.50	1.49	1.55	1.30	1.35	1.61	1.73	1.64	1.48	1.66

CONSOLIDATED PROJECTED OPERATING STATEMENT
(In Millions of Dollars)

For the year ended March 31	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
REVENUES										
General Consumers	2,382	2,441	2,506	2,570	2,641	2,718	2,798	2,876	2,962	3,049
Extraprovincial	984	1,128	1,162	1,311	1,668	1,782	1,808	1,813	1,834	1,847
	3,366	3,569	3,668	3,880	4,309	4,500	4,606	4,689	4,796	4,896
Cost of Gas Sold	301	300	299	299	298	297	297	298	298	298
	3,064	3,268	3,369	3,582	4,011	4,203	4,309	4,391	4,498	4,598
Other	38	38	39	40	41	41	42	43	44	45
	3,102	3,307	3,408	3,622	4,052	4,244	4,351	4,434	4,542	4,642
EXPENSES										
Operating and Administrative	606	618	631	654	667	680	694	707	721	736
Finance Expense	1,198	1,100	1,070	1,162	1,396	1,550	1,526	1,480	1,432	1,375
Depreciation and Amortization	677	687	693	720	792	852	871	874	887	897
Water Rentals and Assessments	121	127	128	135	147	151	153	153	153	154
Fuel and Power Purchased	310	343	358	357	339	337	341	351	370	388
Capital and Other Taxes	154	161	167	172	176	178	179	181	183	184
	3,066	3,037	3,048	3,200	3,517	3,749	3,763	3,747	3,746	3,733
Non-controlling Interest	(24)	(26)	(28)	(29)	(30)	(33)	(36)	(39)	(42)	(45)
Net Income	12	244	332	392	504	462	552	648	753	864
Additional General Consumers Revenue										
General electricity rate increases	3.50%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
General gas rate increases	1.00%	0.00%	1.00%	0.00%	1.00%	1.00%	1.00%	0.00%	1.00%	1.00%
Financial Ratios										
Equity	16%	17%	17%	18%	20%	21%	23%	26%	28%	31%
Interest Coverage	1.01	1.17	1.22	1.25	1.32	1.29	1.35	1.42	1.50	1.59
Capital Coverage	1.51	1.91	1.93	1.98	2.07	2.16	2.28	2.48	2.53	2.58

CONSOLIDATED 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	13,226	15,218	15,745	16,319	17,486	18,051	18,633	22,383	22,907	26,755
Accumulated Depreciation	(4,971)	(5,350)	(5,762)	(6,184)	(6,588)	(7,033)	(7,509)	(8,024)	(8,581)	(9,156)
Net Plant in Service	8,255	9,868	9,983	10,135	10,898	11,019	11,123	14,359	14,326	17,599
Construction in Progress	2,632	1,672	2,314	3,336	3,945	5,506	7,125	5,825	7,283	5,522
Current and Other Assets	1,409	1,512	1,308	1,026	1,169	1,411	1,600	1,858	1,641	1,833
Goodwill and Intangible Assets	227	215	200	187	179	169	163	175	181	188
Regulated Assets	307	321	332	335	331	318	300	279	256	234
	12,830	13,589	14,137	15,020	16,522	18,422	20,311	22,496	23,687	25,376
LIABILITIES AND EQUITY										
Long-Term Debt	8,724	9,144	9,168	10,499	11,917	13,797	15,069	16,614	18,300	15,900
Current and Other Liabilities	1,147	1,352	2,008	1,418	1,493	1,383	1,735	2,167	1,563	5,462
Contributions in Aid of Construction	295	294	288	282	278	275	272	270	267	265
Retained Earnings	2,398	2,532	2,660	2,858	3,013	3,242	3,521	3,748	3,868	4,066
Accumulated Other Comprehensive Income	266	266	12	(38)	(179)	(275)	(286)	(303)	(311)	(317)
	12,830	13,589	14,137	15,020	16,522	18,422	20,311	22,496	23,687	25,376

CONSOLIDATED PROJECTED BALANCE SHEET
(In Millions of Dollars)

For the year ended March 31	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
ASSETS										
Plant in Service	29,560	30,043	30,564	35,140	39,263	40,866	41,483	42,236	42,931	43,588
Accumulated Depreciation	(9,796)	(10,451)	(11,114)	(11,809)	(12,580)	(13,412)	(14,261)	(15,116)	(15,983)	(16,862)
Net Plant in Service	19,764	19,593	19,450	23,332	26,682	27,454	27,222	27,120	26,947	26,726
Construction in Progress	4,442	5,716	6,868	3,752	1,021	231	475	717	1,189	1,653
Current and Other Assets	1,987	1,822	1,802	2,052	2,356	2,598	3,147	3,667	4,068	4,445
Goodwill and Intangible Assets	185	183	182	180	178	177	176	174	173	172
Regulated Assets	213	195	181	168	155	145	137	130	127	124
	26,592	27,509	28,482	29,484	30,393	30,604	31,157	31,808	32,503	33,120
LIABILITIES AND EQUITY										
Long-Term Debt	20,578	21,813	22,614	23,215	23,166	23,366	23,367	23,307	23,058	22,958
Current and Other Liabilities	1,997	1,445	1,291	1,301	1,755	1,304	1,304	1,364	1,553	1,402
Contributions in Aid of Construction	264	262	262	261	261	261	262	263	266	269
Retained Earnings	4,078	4,322	4,655	5,047	5,551	6,013	6,565	7,213	7,966	8,830
Accumulated Other Comprehensive Income	(325)	(334)	(339)	(339)	(339)	(339)	(339)	(339)	(339)	(339)
	26,592	27,509	28,482	29,484	30,393	30,604	31,157	31,808	32,503	33,120

CONSOLIDATED PROJECTED CASH FLOW STATEMENT
(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)	(1,302)	(1,329)	(1,354)	(1,379)	(1,413)	(1,458)	(1,487)	(1,566)
Interest Paid	(419)	(454)	(511)	(510)	(547)	(592)	(588)	(674)	(795)	(837)
Interest Received	25	29	30	26	16	26	39	49	53	48
	564	568	611	654	660	753	822	796	734	843
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	1,200	600	800	1,400	1,600	2,000	1,800	2,400	2,000	1,800
Sinking Fund Withdrawals	651	25	129	463	-	11	-	-	444	175
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)
	598	618	735	1,028	1,500	1,696	1,597	1,869	1,576	1,655
INVESTING ACTIVITIES										
Property, Plant and Equipment, net of contributions	(1,182)	(1,116)	(1,210)	(1,623)	(1,849)	(2,170)	(2,218)	(2,496)	(2,002)	(2,218)
Sinking Fund Payment	(119)	(99)	(117)	(167)	(113)	(199)	(157)	(239)	(207)	(226)
Other	(21)	(16)	(17)	(16)	(17)	(36)	(46)	(27)	(27)	(27)
	(1,321)	(1,231)	(1,344)	(1,806)	(1,980)	(2,405)	(2,422)	(2,762)	(2,236)	(2,472)
Net Increase (Decrease) in Cash	(159)	(45)	2	(124)	179	44	(2)	(97)	74	26
Cash at Beginning of Year	158	(1)	(46)	(44)	(168)	11	55	53	(44)	30
Cash at End of Year	(1)	(46)	(44)	(168)	11	55	53	(44)	30	57

CONSOLIDATED PROJECTED CASH FLOW STATEMENT
(In Millions of Dollars)

For the year ended March 31	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
OPERATING ACTIVITIES										
Cash Receipts from Customers	3,466	3,670	3,770	3,982	4,411	4,603	4,710	4,794	4,902	5,003
Cash Paid to Suppliers and Employees	(1,571)	(1,629)	(1,664)	(1,696)	(1,707)	(1,724)	(1,744)	(1,771)	(1,807)	(1,842)
Interest Paid	(1,224)	(1,126)	(1,072)	(1,160)	(1,411)	(1,577)	(1,553)	(1,521)	(1,487)	(1,434)
Interest Received	44	44	23	25	39	46	49	65	81	87
	716	959	1,058	1,152	1,334	1,349	1,463	1,568	1,690	1,813
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	1,600	1,400	800	600	400	200	-	-	-	-
Sinking Fund Withdrawals	278	722	167	-	-	379	-	-	60	250
Retirement of Long-Term Debt	(403)	(725)	(167)	-	-	(450)	-	-	(60)	(250)
Other	28	(12)	(8)	(8)	(9)	(10)	(11)	(12)	(12)	(13)
	1,503	1,384	792	592	391	119	(11)	(12)	(12)	(13)
INVESTING ACTIVITIES										
Property, Plant and Equipment, net of contributions	(1,807)	(1,748)	(1,664)	(1,449)	(1,375)	(800)	(851)	(981)	(1,155)	(1,106)
Sinking Fund Payment	(299)	(357)	(229)	(238)	(254)	(268)	(260)	(271)	(282)	(290)
Other	(32)	(38)	(29)	(32)	(29)	(30)	(33)	(31)	(32)	(32)
	(2,139)	(2,144)	(1,921)	(1,719)	(1,659)	(1,098)	(1,144)	(1,283)	(1,468)	(1,429)
Net Increase (Decrease) in Cash	80	200	(71)	24	66	370	307	273	209	372
Cash at Beginning of Year	57	136	336	265	289	355	725	1,032	1,305	1,514
Cash at End of Year	136	336	265	289	355	725	1,032	1,305	1,514	1,886

5.0 CAPITAL EXPENDITURE FORECAST

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 - Transmission Line	1,259.9	16.1	24.8	59.9	162.0	298.9	318.5	234.6	120.1	0.4	-	1,235.3
BIPOLE III - Converter Stations	1,828.5	46.3	59.7	148.9	300.3	290.2	294.3	308.5	347.7	2.4	-	1,798.1
BIPOLE III - Collector Lines	191.4	2.1	19.9	52.7	30.1	30.9	34.3	13.5	7.8	-	-	191.4
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
		754.3	717.7	801.5	1,110.9	1,353.7	1,698.7	1,736.5	2,005.2	1,501.3	1,706.4	13,386.1

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	0.0	0.4	2.9	1.5	1.1	0.0	-	-	-	-	6.0
Dorsey 500 kV R502 Breaker Replacement	2.6	0.3	-	-	-	-	-	-	-	-	-	0.3
13.2kV Shunt Reactor Replacements	33.0	0.0	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 Permanent Transformer Addition	21.1	-	-	1.7	8.1	7.5	3.8	-	-	-	-	21.1
Stanley Station 230-66 kV Hot Standby Installation	6.2	1.3	-	-	-	-	-	-	-	-	-	1.3
Enbridge Pipelines: Clipper Project Load Addition Phase 1	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 230 kV Station Reactor Replacement	2.7	0.0	0.0	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	0.0	0.0	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		**1,187.0**	**1,168.7**	**1,240.0**	**1,571.1**	**1,806.2**	**2,129.0**	**2,176.7**	**2,454.7**	**1,959.6**	**2,174.9**	**17,868.0**
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
			2.9									
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
			13.0	17.7	18.8	10.4	10.0					
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		**1,226.6**	**1,209.2**	**1,282.8**	**1,615.3**	**1,842.6**	**2,165.6**	**2,213.2**	**2,491.9**	**1,998.3**	**2,213.7**	**18,259.1**
Target Adjustment		(97.0)	(111.0)	(88.0)	-	-	-	-	-	-	-	(296.0)
CEF10 TOTAL		**1,129.6**	**1,098.2**	**1,194.8**	**1,615.3**	**1,842.6**	**2,165.6**	**2,213.2**	**2,491.9**	**1,998.3**	**2,213.7**	**17,963.1**

6.0 RISK ANALYSIS

The 20 Year Financial Outlook includes a number of key assumptions as described in section 2.0. A change to one or more of those assumptions could have a significant impact on projected financial results. This section provides an indication of the financial impact of changes in the following assumptions:

- Domestic load growth
- Interest rates
- Foreign exchange rates
- Export prices
- Capital expenditures
- Water conditions

Table 2 below shows the change in retained earnings in selected years over the forecast period assuming no change to rate increases relative to the 20 Year Financial Outlook.

Table 2

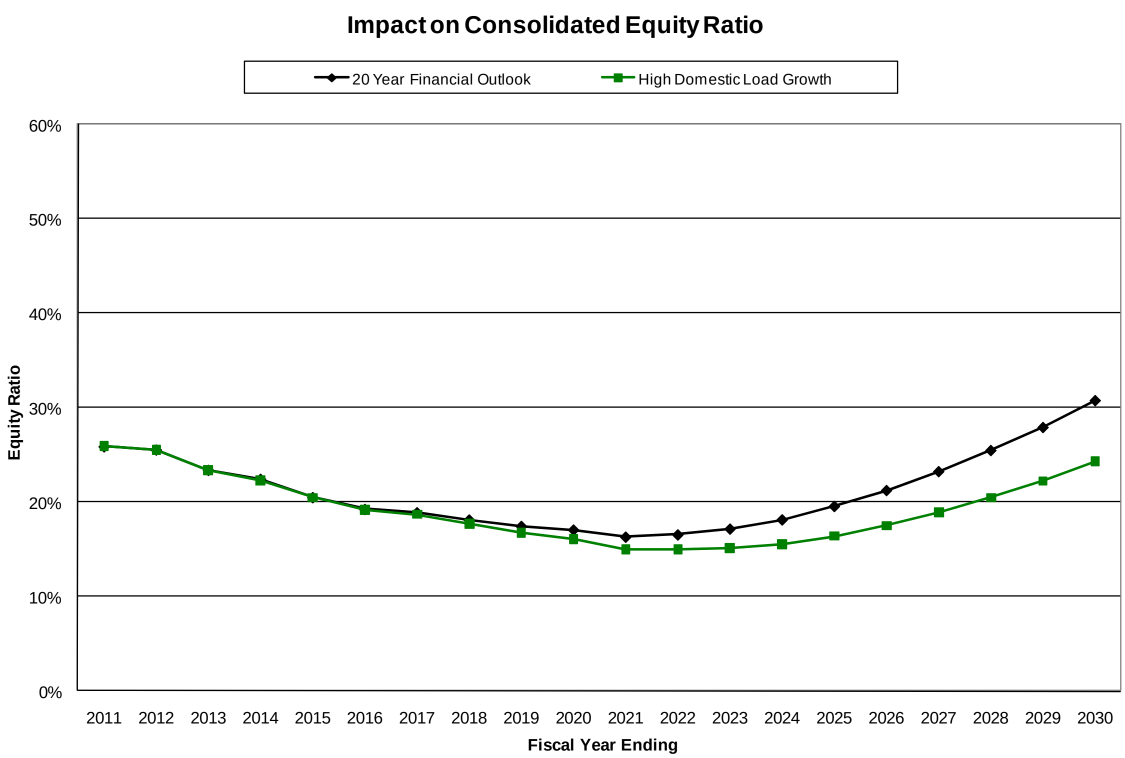
	2012/13	2016/17	2020/21	2029/30
	Incremental Increase/(Decrease) in Retained Earnings (Millions of Dollars)			
20 Year Financial Outlook OL10-2 (Base Case)	2,660	3,521	4,078	8,830
High Domestic Load Growth	(3)	(43)	(281)	(1,772)
+1% Interest	5	(66)	(488)	(3,489)
-1% Interest	(5)	63	458	2,906
US$ up 10¢	26	51	134	1,480
US$ down 10¢	(26)	(43)	(112)	(1,387)
Low Export Price	(42)	(268)	(624)	(2,918)
High Export Price	61	548	1,485	7,003
Capital Expenditures + $100M	(13)	(179)	(566)	(2,460)
5 Year Drought (starting in 2012/13)	N/A	(2,107)	N/A	N/A

6.1 Domestic Load Growth

The base Load Forecast is Manitoba Hydro's best estimate of future growth in domestic energy and peak demand. While current economic circumstances present a risk that the domestic load could be lower than the forecast assumed in the 20 Year Financial Outlook, higher domestic load growth poses greater financial risk to the Corporation due to the displacement of projected higher value exports sales.

The domestic load growth sensitivity, represented by the 90th percentile forecast, includes additional load of 2611 GW.h in net firm energy and 542 MW in net total peak by 2029/30 compared to the base Load Forecast. Figure 7 shows the comparative equity ratios of the High Load Growth Forecast and the 20 Year Financial Outlook.

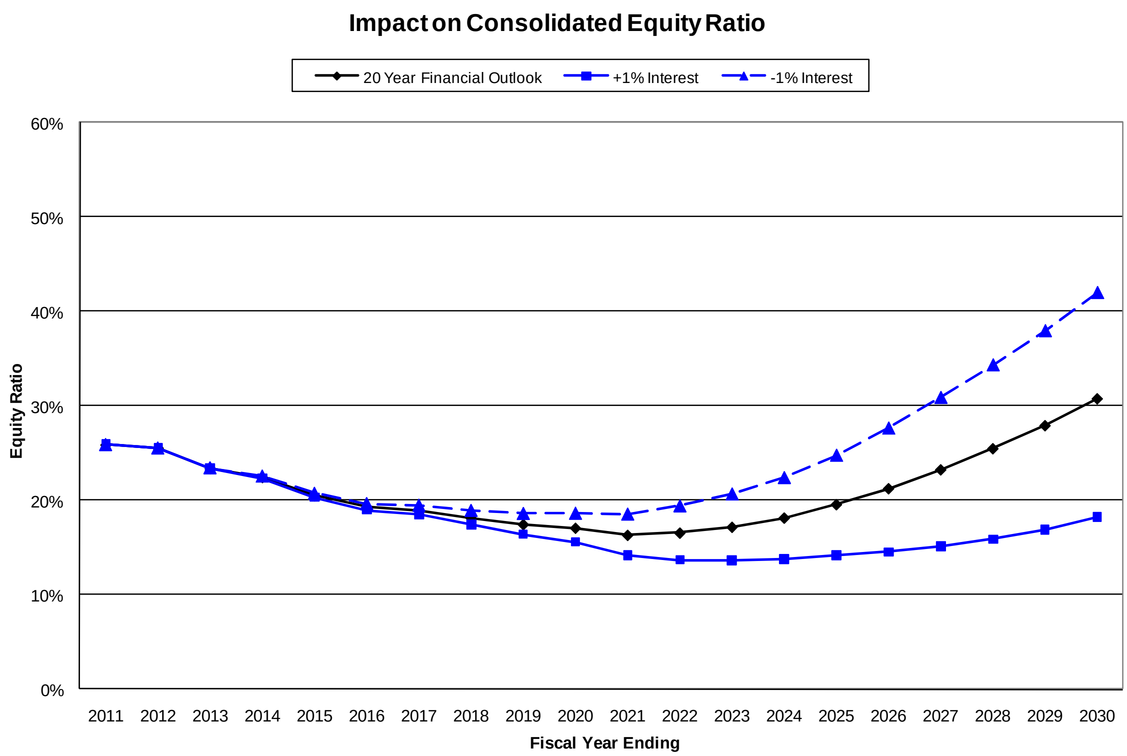
Figure 7



6.2 Interest Rates

Interest rates assumed in the 20 Year Financial Outlook are projected to rise gradually over the first seven years of the forecast. This sensitivity looks at the financial effects of a prolonged increase or decrease in forecast interest rates which are applied to all new long and short-term debt issues, new sinking fund investments and all floating rate debt. Figure 8 below compares equity ratios assuming interest rates increase or decrease 1% each year.

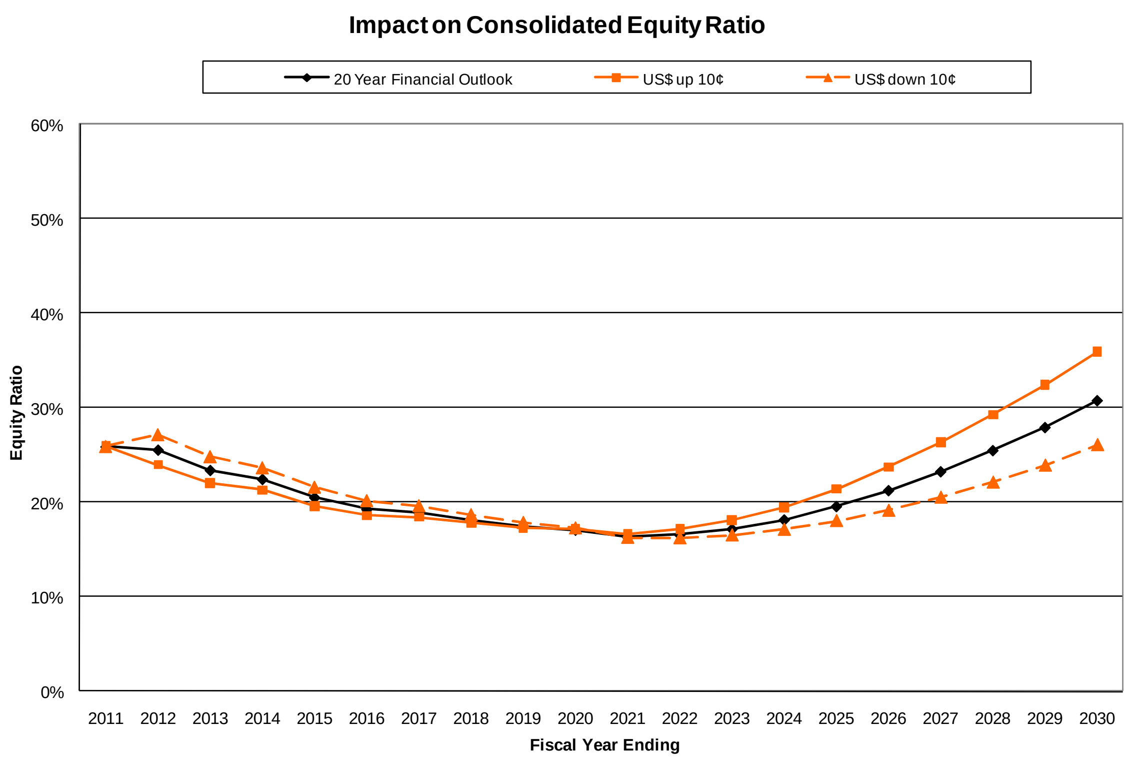
Figure 8



6.3 Foreign Exchange Rates

The Canadian dollar is projected to weaken gradually over the first six years of the 20 Year Financial Outlook. This sensitivity looks at the financial effects of a prolonged weaker or stronger Canadian dollar. In the short to medium term of the 20 Year Outlook, the impacts of a weaker or stronger Canadian dollar are minimal due to the effective hedge provided by Manitoba Hydro's exposure management program. Figure 9 below compares equity ratios assuming US-Canadian exchange rates $0.10 higher or lower than the base 20 Year Financial Outlook.

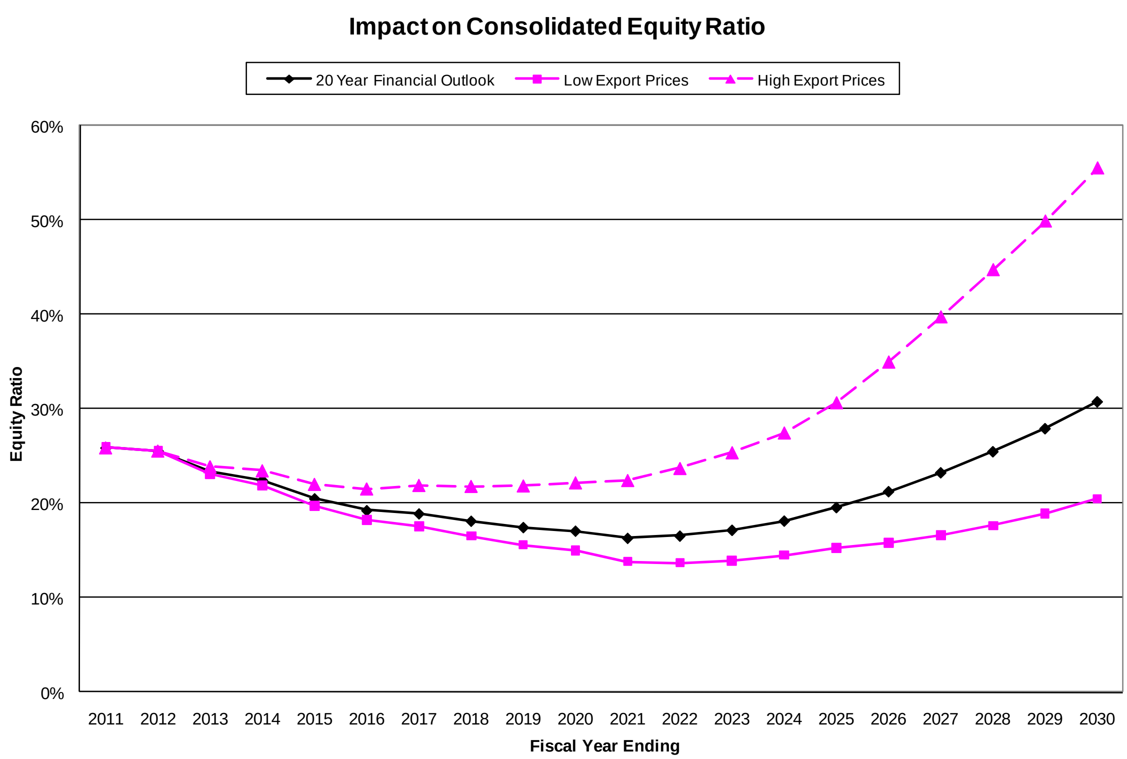
Figure 9



6.4 Low and High Export Prices

The 20 Year Financial Outlook assumes export prices based on externally prepared forecasts. The Low Export Price scenario reflects the long-term impact on future energy prices due to a number of potential factors including low economic growth, aggressive energy conservation policies, low growth in energy demand, lower natural gas and coal prices and lower premiums related to emissions costs. The High Export Price scenario is characterized by high economic and energy demand growth, higher capital costs, higher natural gas and coal prices, stringent US environmental policies and higher environmental premiums. Figure 10 below compares equity ratios under the Low and High Export Price scenarios and the 20 Year Financial Outlook.

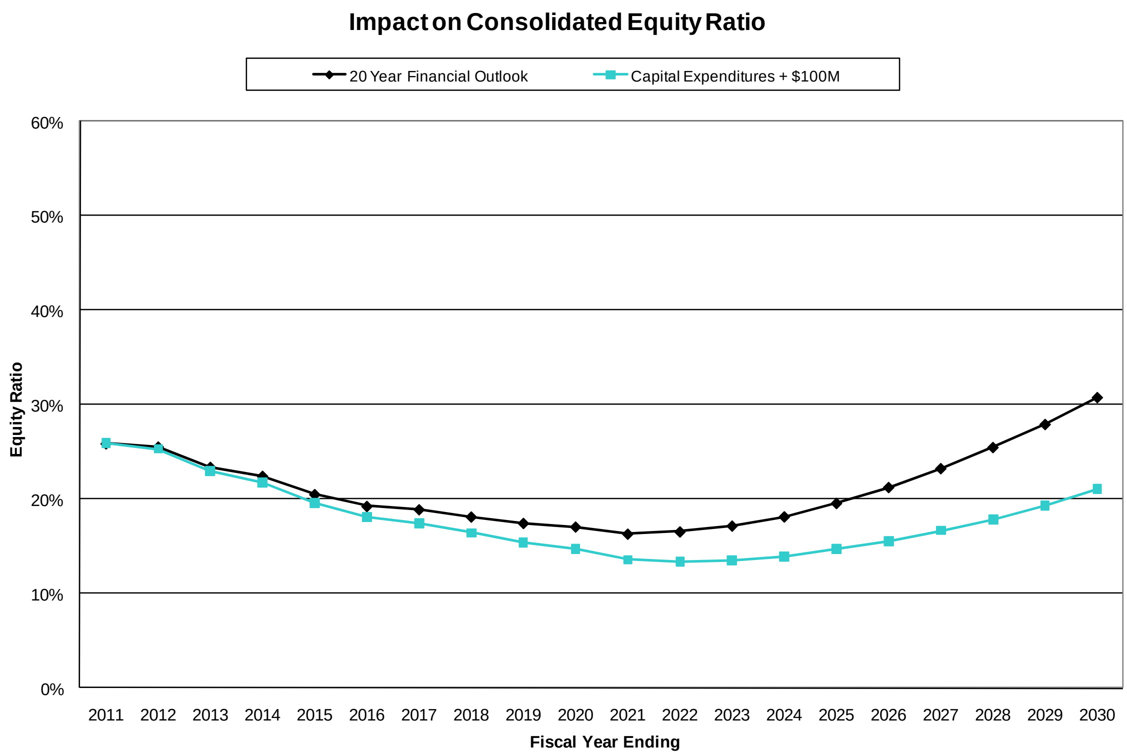
Figure 10



6.5 Capital Expenditures

The 20 Year Financial Outlook includes provisions for increases in base capital expenditures as well as specifically identified capital projects. This sensitivity reflects the financial effects of upward pressure on capital project costs and/or additional expenditures to meet reliability, safety, regulatory or customer requirements. Increases of $100 million per year for electric and $10 million per year for gas have been assumed for non-specified projects. Impacts on the equity ratio are shown in Figure 11 below.

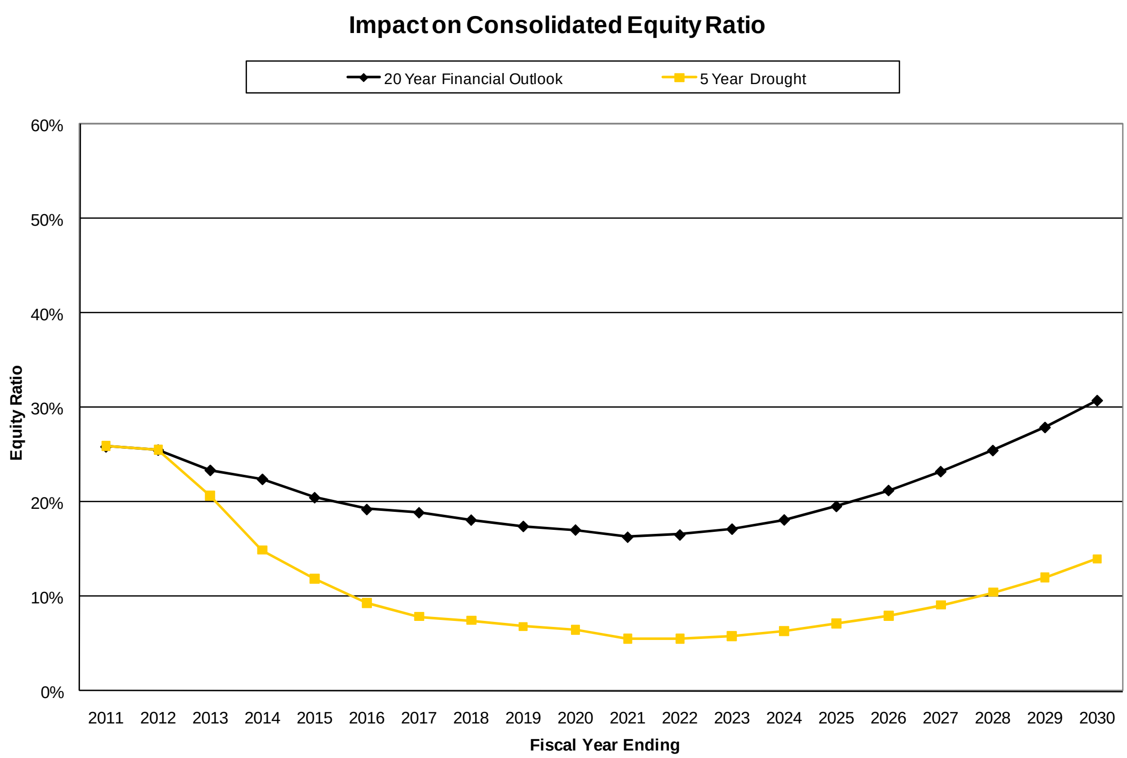
Figure 11



6.6 Five Year Drought

The five year drought scenario shown is identical to the scenario shown in IFF10 and assumes a five year drought commencing in 2012/13. Actual impacts could be smaller or return to normal sooner due to management actions that would mitigate the financial effects of extended low water flow conditions. Figure 12 below compares equity ratios under the 5 Year Drought scenario and the 20 Year Financial Outlook.

Figure 12



7.0 ALTERNATIVE SCENARIOS

7.1 Reliability Alternatives

Manitoba Hydro has a mandate to provide a reliable and dependable supply of power to meet the needs of Manitobans. Currently 70% of the power generated in the Province is transmitted from northern hydro generating stations to the load center in the south of the province via the existing HVdc transmission facilities of Bipole I and II. Bipoles I and II, share a common transmission corridor through the Interlake and a single terminus at the Dorsey converter station.

In the event that either the Dorsey station or the HVdc transmission corridor experiences an outage, the existing system is currently deficient by approximately 1200 MW to meet peak Manitoba load. With Manitoba load growth this deficiency will grow to approximately 1500 MW by 2017 and increasing to 2000 MW by 2025. The loss of the transmission corridor could extend for a period of up to 6 to 8 weeks depending on the extent and location of the damage. A complete loss of the Dorsey station could result in an outage extending for up to 3 years as specialized equipment is ordered, delivered and installed. Such a loss would have extensive impacts to the province, well beyond the economic impacts. The likelihood of a tornado, forest fire, station fire, plane crash or act of sabotage is sufficient to consider options that would accommodate these types of outages and continue to meet the needs of Manitobans.

Bipole III has been incorporated into the Integrated Financial Forecast since 2001 to address system reliability needs and over the years has been refined to reflect detailed design, routing and siting considerations. As an alternative means to address system reliability needs, Manitoba Hydro has considered a solution based on natural gas-fired generation.

Both reliability solutions provide 2000 MW of facilities to protect against an extended Dorsey station outage or loss of the HVdc transmission corridor. Bipole III, at a size of 2000 MW, is planned to be in service by 2017. Under the natural gas alternative, 1500 MW of natural gas-fired generation is planned to be in service by 2017 followed by an additional 500 MW of natural gas-fired generation to be in service by 2025, as required to serve growing Manitoba load.

Table 3 below shows the comparative capital and fixed operating costs of both the Bipole III and natural gas reliability alternatives.

Table 3
(Millions of Current Dollars)

	Bipole III			All Gas Reliability Option		
	Capital	Fixed Operating	Total	Capital	Fixed Operating	Total
Actuals to March 31, 2011	102	-	102	-	-	-
2011	17	-	17	-	-	-
2012	104	-	104	-	-	-
2013	261	-	261	-	-	-
2014	492	-	492	-	-	-
2015	620	-	620	174	-	174
2016	647	-	647	902	-	902
2017	557	-	557	1,062	-	1,062
2018	476	12	488	231	128	359
2019	3	13	15	157	131	288
2020	-	13	13	197	135	332
2021	-	13	13	133	140	273
2022	-	13	13	84	145	229
2023	-	14	14	45	149	194
2024	-	14	14	4	153	157
2025-2045	-	373	373	-	4,079	4,079
Total Cost	**3,280**	**466**	**3,746**	**2,988**	**5,061**	**8,049**
Present Value (2010$)	**1,817**	**7**	**1,823**	**1,337**	**1,014**	**2,351**

The cost of Bipole III is $3.28 billion with minimal operation and maintenance costs over the asset life. Bipole III provides reduced losses on the existing HVdc system of 77 MW and 243 GW.h/yr of dependable energy, with additional energy savings when northern generation is higher. When Bipole III is used to support planned or unexpected outages, virtually no incremental cost would be incurred. Bipole III also provides flexibility when planning for future resources including continued development of the hydro potential in northern Manitoba.

The cost of installing 2000 MW of gas turbines is estimated to be $2.99 billion. To ensure that these gas facilities are available to meet a sudden and extensive demand, a firm gas supply is required at an average cost of $181 million per year. When called upon to support planned or unexpected outages substantial operating, maintenance and fuel costs would be incurred. This alternative exposes Manitoba Hydro to natural gas price volatility and restricts resource options when planning for future development.

On a present value basis (2010 dollars), total capital and fixed operating costs of Bipole III are more than $500 million lower than the gas reliability alternative. As a result of the significantly lower cost and the substantial benefits offered by Bipole III, Bipole III is the preferred reliability solution.

It should also be noted that pursuing an all gas reliability option would result in the loss of significant economic benefits to the province, the cancellation of lucrative export contracts, higher electricity bills to domestic customers, a reduction in interconnection reliability, stranded capital costs, and negative environmental impacts.