April 2017

Integrated Financial Forecast (IFF16)

2016/17 – 2026/27

Strategic & Financial Planning Department
Finance & Strategy

Manitoba Hydro

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INTEGRATED FINANCIAL FORECAST (IFF16)

2016/17– 2026/27

STRATEGIC & FINANCIAL PLANNING DEPARTMENT
FINANCE & STRATEGY
APRIL 2017

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KEY FINANCIAL RESULTS

(Dollars are in millions)

Key Financial Results	Actual	IFF16 Forecast			
	2015/16	2016/17	2017/18	2018/19	2026/27
PROJECTED RATE INCREASES					
Electric	3.95% (1)	3.36% (2)	7.90% (3)	7.90% (4)	2.00%
Gas (non-commodity)	-	-	(1.00%) (5)	-	1.75%
NET INCOME					
Electric	$37	$34	$111	$242	$440
Gas	(1)	(0)	(1)	3	3
Subsidiaries	9	7	8	9	13
CAPITAL EXPENDITURES					
Electric	$2 255	$2 884	$3 002	$2 643	$664
Gas	$46	$51	$31	$32	$40
DEBT/EQUITY RATIO	83:17	84:16	85:15	85:15	74:26
EBITDA INTEREST COVERAGE RATIO	1.55	1.54	1.60	1.79	2.31
CAPITAL COVERAGE RATIO (excl. major new generation & transmission)	1.37	1.10	1.30	1.54	2.08
NET DEBT	$13 571	$15 689	$18 596	$20 851	$20 826
RETAINED EARNINGS	$2 828	$2 871	$2 993	$3 245	$6 967

(1) The PUB approved 3.95% effective August 1, 2015 with 1.80% accruing to domestic revenues and 2.15% accruing to the Bipole III deferral account.

(2) The PUB approved 3.36% effective August 1, 2016 accruing to a deferral account to be utilized to mitigate the anticipated rate impact when Bipole III is placed in-service.

(3) The proposed 7.90% rate increase for 2017/18 is assumed to be effective August 1, 2017.

(4) The proposed 7.90% rate increase for 2018/19 is assumed to be effective April 1, 2018.

(5) The 1.00% rate decrease reflects the prospective roll-back per Order 108/15 of the non-gas rate increase approved in the 2013/14 GRA; see section 15.0 for more detail.

EXECUTIVE SUMMARY

The Consolidated Integrated Financial Forecast (IFF16) provides projections of Manitoba Hydro's financial results and position for the current year outlook and the 10-year period from 2017/18 to 2026/27. The current year outlook reflects actual financial results to January 31, 2017, actual water flow conditions to January 31, 2017 and corresponding reservoir effects carried forward through the 2017/18 forecast year. Segmented forecasts are also provided for electricity (MH16), natural gas (CGM16), and corporate subsidiaries (CS16).

IFF16 projects net income of $44 million for 2016/17, $122 million for 2017/18 and $252 million for 2018/19. IFF16 incorporates five years of annual rate increases of 7.90% from 2017/18 to 2021/22 followed by 2.0% per year thereafter. These forecasted financial results are subject to several key variables, such as approval of rate increases by the Public Utilities Board (PUB), the actual cost and in-service dates for major capital projects, water flows, export prices, interest rates, and the timely achievement of significant staff reductions and operating cost efficiencies.

IFF16 incorporates the Keeyask Hydropower Limited Partnership (KHLP) new control budget of $8.7 billion for the Keeyask Project and a revised in-service date of August 2021. The new control budget is based on the construction progress to date and a broader review of the remaining work required to complete the project.

Manitoba Hydro has increased the Bipole III Reliability Project control budget to $5.0 billion from $4.7 with a planned in-service date of July 2018.

Overall, the Capital Expenditure Forecast (CEF16) increased by $2.5 billion over the 10-year period (2017/18 to 2026/27) compared to CEF15 (see **Section 9.0**), and the new Keeyask control budget and an increase to the Bipole III Reliability project account for the majority of the net change. Decreases in Business Operations Capital partially offset the Major New Generation & Transmission (MNG&T) increases.

Domestic electricity sales at current approved rates and net of planned Demand Side Management (DSM) programs are essentially flat over the first ten years of the forecast to 2026/27. The 2016 Electricity Load Forecast reflects lower usage in the residential and mass market sectors and a revised expectation regarding the prospects of new large industrial loads entering the Manitoba market. Manitoba Hydro has not incorporated any additional cost or load impacts from the proposed Efficiency Manitoba entity or legislated DSM targets.

Despite the surplus energy available for export resulting from very favourable water flows, energy markets have continued to evolve in a manner that has put further downward pressure on long-term power prices. The decline to long-term power prices is due primarily to a reduction to long-term natural gas prices and increased renewable development (primarily wind generation) in the Midcontinent Independent System Operator (MISO) market, aided by substantial subsidies. Overall, the 2016 electricity export prices are down roughly 20% relative to the comparable 2015 forecast. The reduction to long-term power prices and the 21-month delay to the Keeyask project results in a $700 million reduction to net extraprovincial revenue (extraprovincial revenue less fuel and power purchased and water rentals and assessments) over the period 2016/17 to 2026/27 compared to IFF15.

IFF16 incorporates Manitoba Hydro's planned corporate restructuring and cost reduction program and reflects the anticipated reduction of 900 positions through a combination of a planned voluntary reduction program, the completion of the Bipole III Reliability and Keeyask projects and natural attrition.

The increases to MNG&T projects and the reduction to the revenue forecast have put further downward pressure on the financial outlook of the Corporation. The following three major outcomes are driving the need for five years of higher annual rate increases:

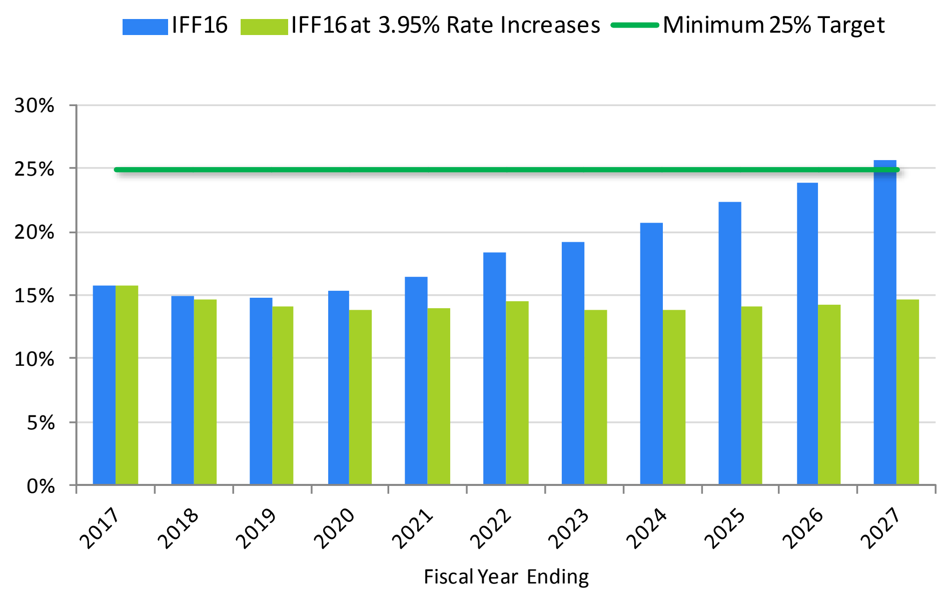
i. the projected increase of Manitoba Hydro's net debt to unprecedented levels has the potential to place significant strain on the financial stability and risk profile of the Corporation;

ii. the need to eliminate the ongoing deficit funding (i.e. negative cash flow) of normal business operations; and

iii. the need to accelerate the attainment of the minimum 25% target equity ratio to manage risk and preserve Manitoba Hydro's self-supporting status.

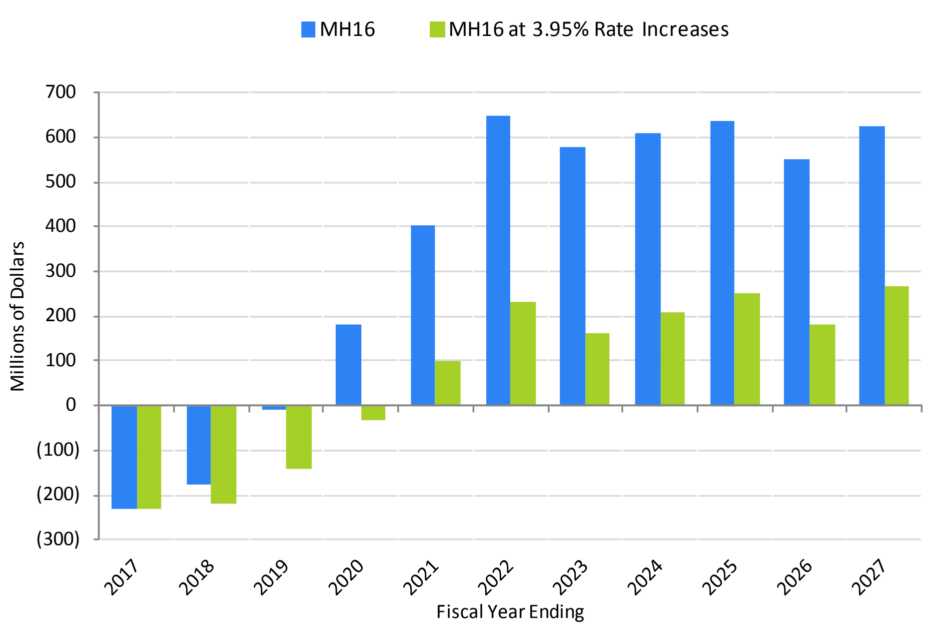
Manitoba Hydro believes that the corporate cost reduction program in conjunction with annual rate increases will lower the overall amount of new debt needed over the next five to seven years, will reduce the likelihood of any further deterioration of the equity ratio and increase the chance of advancing the achievement of the minimum 25% target within the first ten years of the forecast, and will help reduce the near-term funding deficit of normal business operations. Ultimately, the Corporation will be strengthening the balance sheet and will be in a much better financial position to deal with significant potential financial risks (drought, rising interest rates and lower export prices) without having to rely on large, unplanned rate increases (i.e. ”rate shock”) to sustain operations. If the previous plan's 3.95% rate increase pattern were included in IFF16, the consolidated equity ratio, as reflected in the following figure, would not progress upward within the 10-year forecast period and the return to the 25% equity target would not occur until near the end of a 20-year period.

Consolidated Equity Ratio



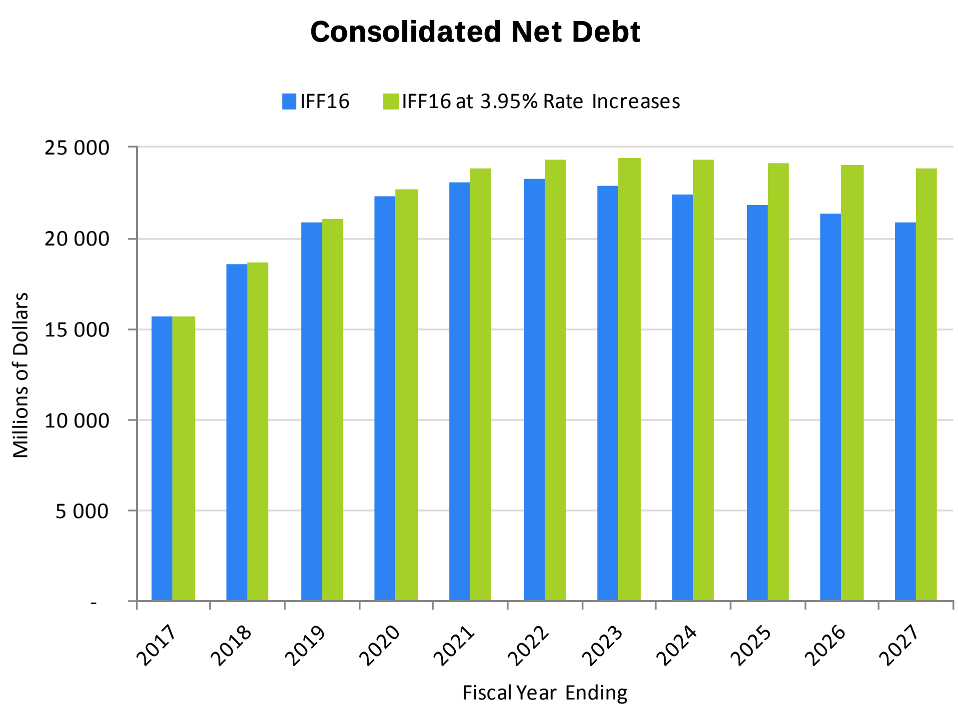
The previous 3.95% rate trajectory included in IFF15 would result in Manitoba Hydro deficit funding its normal operations until 2020/21 despite the planned cost reduction program as shown in the following figure reflecting cash flow from operations:

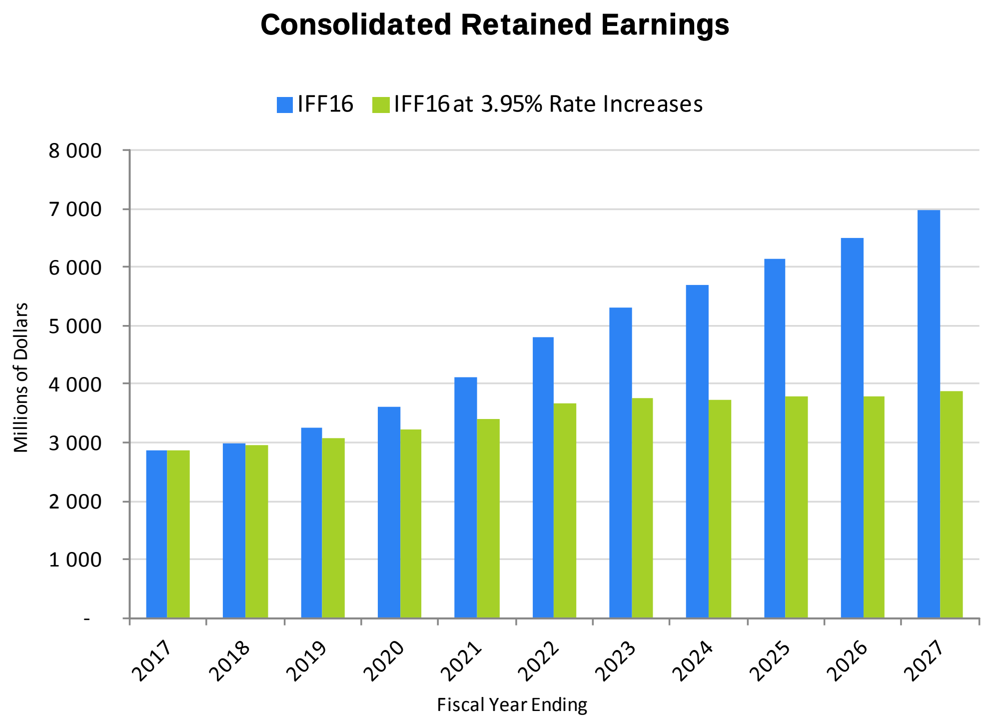
Electric Operations Cash Flow from Operations Surplus / (Deficiency)



It must be recognized that Manitoba Hydro electric operations net plant in service increases over the 11-year period from approximately $12 billion to almost $27 billion in 2026/27. Even with cost reductions and the proposed rate increases, debt will peak at $23 billion in 2021/22. The appropriate amount of net income and positive cash flow Manitoba Hydro should generate should reflect the growing size of its balance sheet and the risks associated with the significant levels of debt required to fund this investment. Levels of net income and cash flow appropriate for a Corporation with $12 billion of assets in service must be scaled up significantly to reasonably address the risks associated with operating $27 billion worth of assets (at historical book value).

Increased levels of cash flow and net income will consequently result in reductions in net debt and improvements to the levels of retained earnings (shown in the figures below) which are necessary for steady progress towards the minimum 25% equity target in the first ten years of the forecast.




Consolidated Retained Earnings
IFF16
IFF16 at 3.95% Rate Increases
Millions of Dollars
8 000
7 000
6 000
5 000
4 000
3 000
2 000
1 000
-
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
Fiscal Year Ending

1.0 INTRODUCTION

IFF16 provides projections of Manitoba Hydro's financial results and position for the current year outlook and the 10-year period from 2017/18 to 2026/27. Its purpose is to project the Corporation's long-term financial direction. The IFF serves as the primary forecast to determine the need for rate increases that are necessary for the Corporation to maintain a reasonable financial position and progress towards attaining and maintaining its financial targets. Maintaining the financial strength of the Corporation is necessary to provide customers with long-term rate stability and predictability.

The forecast is the culmination of an extensive integrated planning cycle at Manitoba Hydro. It is based on the best available information at the time it is prepared and includes forward looking information that incorporates expectations, estimates and assumptions concerning the future which are subject to change. Key inputs to the Integrated Financial Forecast (IFF) include:

- Economic Outlook,
- Energy Price Outlook,
- Electricity Export Price Forecast,
- Power Smart Plan,
- Electric Load Forecast,
- Natural Gas Volume Forecast,
- Domestic Revenue Forecast,
- Resource Planning Assumptions & Analysis for 2015/16 Corporate Planning,
- Generation Costs and Interchange Revenue Forecasts,
- Capital Expenditure Forecast, and
- Operating & Administrative Expense Forecast.

Key inputs are monitored over the planning cycle through to the finalization of the IFF and are updated as required for significant changes.

This forecast supersedes the 2015 Integrated Financial Forecast (IFF15) which was approved by the Manitoba Hydro-Electric Board (MHEB) in December of 2015.

2.0 RATES & ECONOMIC VARIABLES

2.1 Electricity Rates

Manitoba Hydro's base electricity rates include a 3.36% rate increase effective August 1, 2016 approved on an interim basis by the Manitoba Public Utilities Board (PUB) in Order 59/16 dated April 28, 2016. Final approval will be sought in the next General Rate Application (GRA) to be filed with the PUB in early 2017.

The revenues associated with the 3.36% interim rate increase are being accrued to the Bipole III deferral account established in PUB Order 43/13. At March 31, 2017, cumulative revenues accrued to the Bipole III deferral account are $196 million. The Bipole III deferral account is projected to grow to just over $350 million by the Bipole III Reliability planned in-service date. The PUB's endorsement of Manitoba Hydro's proposed disposition of the Bipole III deferral account will be sought in the 2017 GRA; however for the purposes of IFF16, it is assumed that the deferral account is recognized in general (domestic) revenues over five years upon forecasted in-service from August 2018 to July 2023 (compared to three years in IFF15).

The previous financial plan projected the requirement for minimum electric rate increases of 3.95% each year to 2028/29 before the expected move to inflationary level rate increases in the order of 2.00% per year.

The revised financial plan, IFF16, approved by the MHEB in April 2017, proposes annual rate increases of 7.90% for five years, 2017/18 to 2021/22, followed by inflationary rate increases of approximately 2.00% thereafter. In its 2017 GRA, Manitoba Hydro is seeking PUB approval for 7.90% effective August 1, 2017 on an interim basis and 7.90% effective April 1, 2018.

Proposed rate increases subsequent to 2018/19 are subject to change in future forecasts. Each year's revision to the IFF is based on the current year's assumptions including energy supply and demand, projected interest, escalation and exchange rates, projected prices for exported energy, operating and capital forecasts, and other factors. Changes in any of these assumptions will have an impact on the projected future results. Actual rate applications made in future years will depend upon the circumstances and outlook at that time and will be subject to the review and approval of the MHEB.

2.2 Gas Rates

Centra Gas is not seeking an increase to the non-gas component of its rates 2017/18 or 2018/19. CGM16 projects its next rate increase of 1.00% will be required in 2020/21 with a subsequent 1.50% rate increase in 2022/23, 1.25% rate increase in 2023/24, 1.00% rate increase in 2024/25, and a 1.75% rate increase in 2026/27. Non-gas rate increases are projected as required effective August 1 in order to generate net income of approximately $3 million. Projected rate increases may change in future forecasts subject to the circumstances of the day.

In Order 108/15 flowing from Centra's 2015/16 Cost of Gas Application, the PUB indicated that the non-gas cost revenue requirement needs to be reviewed in the context of the next GRA, to be filed by no later than January 20, 2017. In the absence of a Gas GRA, the 1.00% domestic revenue increase previously approved by the PUB following the 2013/14 Gas GRA would be reversed effective August 1, 2017. Manitoba Hydro advised the PUB that it would not be in a position to file a Gas GRA by January 20, 2017. As such, CGM16 assumes that the non-gas component of rates will revert back to levels previously approved by the PUB prior to the 2013/14 Gas GRA effective August 1, 2017, resulting in a reduction of $3-4 million in annual domestic revenue.

2.3 Economic Outlook

The economic assumptions used in the forecast are based upon Manitoba Hydro's 2016 Economic Outlook, with exchange rates updated as of June 2016[1] and interest rates updated as of December 2016 to reflect current economic conditions at that time. The Economic Outlook forecasts are based on a consensus view of several independent sources including Canada's primary financial institutions and several other independent sources. The following **Table 2-1** provides the key economic indicators incorporated in IFF16:

[1] The December 2016 update was limited to interest rates to support the calculation of the revised Keeyask control budget. U.S. exchange rates were not updated due to Manitoba Hydro's hedging strategy and the resulting minimal impact on the projected financial statements.

Table 2-1: Economic Variables

Key Economic and Financial Indicators (1)				
	Manitoba Consumer Price Index	MH New Short Term Cdn Interest Rate (2)	MH New Long Term Cdn Interest Rate (2)	US-CDN Exchange Rate (C$/US$)
2016/17	1.80%	0.50%	2.20%	1.30
	(2.2%)	(0.55%)	(3.35%)	(1.32)
2017/18	2.00%	0.50%	2.50%	1.28
	(2.0%)	(1.40%)	(3.80%)	(1.25)
2018/19	2.00%	0.85%	2.95%	1.25
	(2.0%)	(2.40%)	(4.40%)	(1.22)
2019/20	2.00%	1.40%	3.25%	1.21
	(2.0%)	(3.00%)	(4.50%)	(1.19)
2020/21	1.90%	1.75%	3.45%	1.21
	(2.0%)	(3.00%)	(4.60%)	(1.16)
2026/27	1.70%	2.70%	4.10%	1.15
	(2.1%)	(3.00%)	(4.60%)	(1.16)

(1) 2015 Projected Rates in brackets
(2) Excludes the 1% Provincial Guarantee Fee

The IFF is expressed in current (nominal) Canadian dollars. The forecast of CPI is used to adjust constant (real dollars) where appropriate, for example, capital and operating expenditures, to current dollars. The long-term outlook for CPI shows downward pressure due to the assumption of falling commodity prices.

The forecast of Canadian exchange rates is used in the conversion of U.S. export revenues, electricity imports, natural gas and coal purchases, interest payments, and general materials and contract services purchased from U.S. vendors. The Canadian exchange rate is expected to trend from $1.30 in 2016/17 to $1.15 in the long-term. The expectation of a U.S. Federal Reserve hike coupled with falling oil prices is expected to put downward pressure on the Canadian dollar well below parity to the end of the 2016. The Economic Outlook forecasts that as oil prices begin to climb and with expected interest rate hikes by the Bank of Canada, upward pressure will be put on the Canadian dollar causing it to appreciate.

The drop in the Bank of Canada target overnight policy rate has caused the lowering of long-term bond yields with the expectation that it will take longer to reach an equilibrium rate. The consensus survey expects the Bank of Canada to keep rates steady for the next year with a move to increase interest rates in 2018. The U.S. Federal Reserve approved a quarter point to half point increase in its target funds rate range in mid December 2016 which is the first increase since the rate was taken to zero in 2008 as a result of the financial crises. The economic outlook forecasts that short and long-term interest benchmark interest rates will gradually rise over the last half of the forecast period.

New to this year's forecast is the introduction of forecasted long-term interest rates assuming a weighted average 12-year term to maturity compared to a 20-year weighted average term to maturity in IFF15. These rates are used to forecast interest payments on fixed long-term advances in the IFF. The debt management strategy to issue a greater proportion of bonds with shorter terms to maturity is discussed in further detail in **Section 10.0** of this report.

2.4 Electricity Export Prices

The "2016 Electricity Export Price Forecast" (PPD# 16/13 approved July 2016) forms the basis for all market energy pricing in IFF16 with an adjustment to the forecast in January 2017 to reflect the current trends in projected on-peak, off-peak prices, and capacity values.

The forecast represents a compilation of forecasts obtained from five consultants for the 20-year horizon period from 2018/19 to 2037/38 for the Minnesota Hub of the MISO market footprint, Manitoba Hydro's primary power market region for wholesale electricity. A consensus forecast is prepared weighting each consultant's forecast equally. Each consultant utilizes their own electricity price forecast models, assumptions, and view of the future. Additionally, each consultant prepares their own estimates for key factors including future thermal fuel prices, load growth, characteristics of the existing and potential new generation fleet, generation retirements, power market rules, and future regulatory and/or legislative requirements related to environmental protection.

The projections in the July 2016 Electricity Export Price Forecast are overall 10% lower than the 2015 projections largely due to sustained natural gas price projections and a reduction in the market value of capacity. This reduction includes the removal of the premium that has historically been applied to the long-term dependable forecast prices, as the achievability of this premium has reduced significantly in the MISO market.

In January 2017, the forecast of electricity export prices was further reduced in the order of 10% based on further dampening of electricity prices due to the continued downward trend of natural gas prices since the July 2016 forecast among other trends. Reflecting the continuing trend of low capacity value, the January 2017 update also removed capacity prices from the pricing of potential future uncommitted export sales from surplus dependable energy. This resulted in the removal of forecasted uncommitted firm sales and replacing available energy with opportunity sales, which reduces import requirements under low flow cases to meet firm sales.

3.0 MANITOBA DEMAND FOR ELECTRICITY

Domestic revenue is forecast based on the future load requirements in Manitoba as projected in the 2016 Electric Load Forecast. The Load Forecast includes DSM savings achieved to date as well as projected savings achieved through codes and standards. Planned additional savings are incorporated in the forecast of domestic revenue separately from the Load Forecast and are discussed in **Section 4.0** below.

The 2016 Load Forecast projects gross firm energy in Manitoba will grow from a weather adjusted value of 25,355 GWh in 2015/16 to 29,447 GWh in 2026/27. This average growth is 375 GWh or 1.4% per year for 11 years before program-based DSM initiatives. Over the same 11-year period, total system peak is projected to grow forecast to grow at about the same pace as gross firm energy, by 71 MW or 1.4% a year for the next 11 years to 5,402 MW by 2026/27. The system load factor is projected to remain relatively constant at approximately 62%.

MH16 includes an adjustment to the 2016 Load Forecast to reflect lower actual usage and weather data available for the ten months included in 2016/17, as well as anticipated changes for the 2017 Load Forecast related to lower preliminary population forecasts and reduced expectations for new large industrial loads. Due to timing of availability, the adjustment does not factor in other potential changes that would be captured in the 2017 Load Forecast including price elasticity to the 7.90% proposed and indicative rate increases included in MH16, other updated economic inputs, or other changes in projected consumption that would result in year-to-year variations from the 2016 Load Forecast. Manitoba Hydro is monitoring the proposed establishment of Efficiency Manitoba and legislation of DSM targets in order to assess further impact on load growth and expenditures.

The reduction to gross firm energy from the 2016 Load Forecast is anticipated to be approximately 1,000 GWh by 2035/36 which is equivalent to the 24th percentile probability point of the 2016 Electric Load Forecast based upon the load variability analysis presented at page 44 of the 2016 Electric Load Forecast report. The 24th percentile point was selected as a proxy for Manitoba's anticipated future load requirements in the 20th year of the 2017 Load Forecast. The following comparisons are made between the 2015 Load Forecast and the 2016 Load Forecast, including the adjustment discussed above.

- Gross firm energy (before program-based DSM initiatives) in Manitoba is forecast to grow on average by approximately 300 GWh or 1.2% per year over the 11-year forecast period to 2026/27.
- Gross total peak is forecast to grow at the same pace as gross firm energy, by approximately 55 MW or 1.2% a year over the 11-year forecast period to 2026/27.

- Compared to the 2015 Load Forecast, gross firm energy is projected to be about 700 GWh (2.6%) lower in 2016/17 primarily due to the lower residential and commercial market sector load experienced in 2014/15 and 2015/16, along with changes in the large industrials short-term plans.
- By 2026/27, gross firm energy is expected to be approximately 2,100 GWh (6.8%) lower in comparison to the 2015 Load Forecast (including the adjustment from the 2016 Load Forecast), primarily due to the reduced expectations for new large industrial loads and a decrease in the population forecast lowering the residential and commercial market sectors, representing a reduction of approximately five years of load (1 year = approximately 442 GWh).
- Consistent with gross firm energy, gross total peak is forecast to be about 400 MW (6.9%) lower in 2026/27 than the 2015 Load Forecast or a reduction of approximately five years of load growth (1 year = approximately 80 MW).

4.0 DEMAND SIDE MANAGEMENT

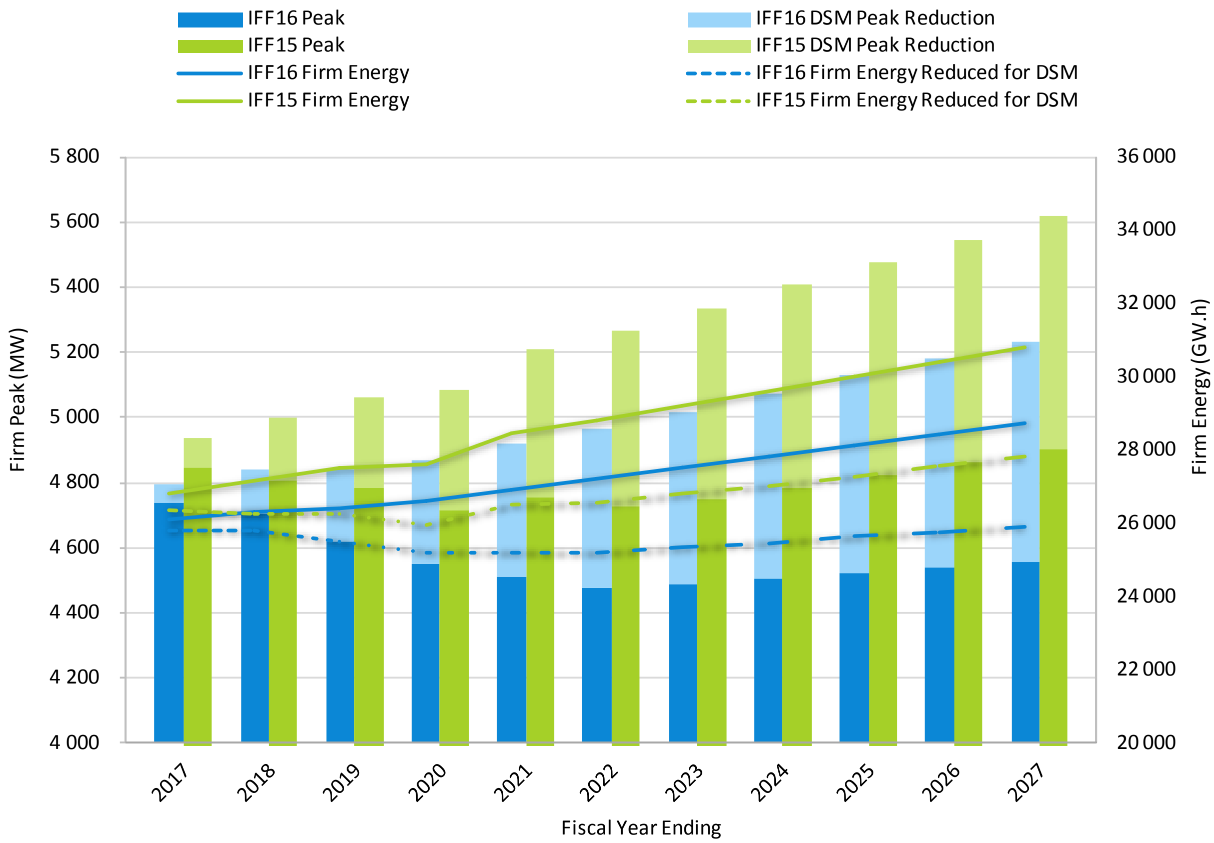
On March 9, 2017, the Provincial Government tabled legislation to create a new Crown Corporation – Efficiency Manitoba – which will assume responsibility for efficiency initiatives with an initial focus on reducing electricity and natural gas consumption in Manitoba. Under Bill 19, Efficiency Manitoba is required to achieve electrical energy savings of 1.5% annually during the first 15 years of its operations. Shortfalls and surpluses in annual net savings carry forward during the 15 year period such that Efficiency Manitoba is required to demonstrate electrical energy savings of 22.5%. For the three-year period following the commencement date, and for each three-year period after that, Efficiency Manitoba must prepare and submit an efficiency plan to the PUB for review and approval.

Under the proposed legislation, Manitoba Hydro will also continue to be responsible for the costs of meeting the legislated targets. Until Efficiency Manitoba is established and delivers its initial efficiency plan, it is uncertain at this time what the impacts of Efficiency Manitoba and legislated DSM targets will be on forecast domestic load in IFF16. In the interim, IFF16 continues to incorporate the costs and savings reflected in Manitoba Hydro's current Power Smart Plan in the same manner as previous forecasts.

The "2016/17 Demand Side Management Plan – Supplemental Report 15 Yr (2016-2031)" targets savings similar to that in the 2015 Plan and proposes to realize electricity savings of 1,232 MW and 4,506 GWh, natural gas savings of 130 million cubic meters, and combined global greenhouse gas emission reductions of 3.3 million tonnes by 2030/31. The 2015 Plan, by comparison targeted 1,288 MW and 4,619 GWh in electricity savings, 118 million cubic meters of natural gas savings, and combined global greenhouse gas emission reductions of 3.3 million tonnes by 2029/30.

The following **Figure 4-1** combines the forecast gross energy and peak requirements projected in the Load Forecast with the planned additional DSM energy and capacity savings from the Power Smart Plan. Manitoba Hydro's gross firm energy (lines) and peak (bars) are compared to firm energy and peak net of DSM savings (solid lines and bars, respectively), as well as a comparison between the 2015 (green) and 2016 (blue) forecasts.

Figure 4-1: Electric Load Forecast and DSM Reductions



Energy, net of DSM savings, in MH16 shows no growth over current levels by 2026/27 compared to 0.5% average annual growth in MH15. MH16 capacity, net of DSM savings, is projected to decline by 0.3% over the 11-year forecast period compared to 0.1% average annual growth in MH15. Load growth, net of DSM savings, is flat in MH16 due mainly to the methodology change in forecasting for the large industrial sector which excludes the anticipation of new large industrial customers in Manitoba, reflecting only anticipated changes in the load profiles of existing industrial customers.

Domestic revenues at current PUB approved rates are projected to be $0.9 billion lower from 2016/17 to 2026/27 compared to MH15. The reduction in energy sales to Manitobans are assumed to be replaced by firm export sales with minimal impact to Manitoba Hydro earnings or customer rates. This is demonstrated in the sensitivity analysis found in **Section 17.1** where a reduction from the 24th percentile load to the 10th percentile load results in a cumulative earnings effect of $179 million by 2026/27.

5.0 EXTRAPROVINCIAL REVENUE

IFF16 includes the following long-term firm export sales:

Minnesota Power 50 MW System Participation	May 2015	to	May 2020
Minnesota Power 250 MW System Participation	Jun 2020	to	May 2035
Minnesota Power 50 MW ZRC System Participation	Jun 2017	to	May 2020
Great River Energy 200 MW Seasonal Diversity	Nov 2014	to	Apr 2030
Northern States Power 125 MW System Power	May 2021	to	Apr 2025
Northern States Power 375/325 MW System Power	May 2015	to	Apr 2025
Northern States Power 350 MW Seasonal Diversity	May 2015	to	Apr 2025
Northern States Power 75 MW Seasonal Diversity	Jun 2016	to	May 2020
Wisconsin Public Service 100 MW Sale	Jun 2021	to	May 2027
Wisconsin Public Service 108 MW System Participation	Jun 2016	to	May 2021
SaskPower 100 MW System Participation	Jun 2020	to	May 2040
SaskPower 25 MW System Participation	Nov 2015	to	May 2022
American Electric Power 79 MW ZRC	Jun 2016	to	May 2018
American Electric Power 50 MW ZRC	Jun 2018	to	May 2020
Basin Electric 50 MW ZRC System Participation	Jun 2018	to	May 2020
Basin Electric 50 MW ZRC System Participation	Jun 2020	to	May 2021
NextEra 30 MW ZRC Sale	Jun 2015	to	May 2018
NextEra 100 MW ZRC Sale	Jun 2016	to	May 2018

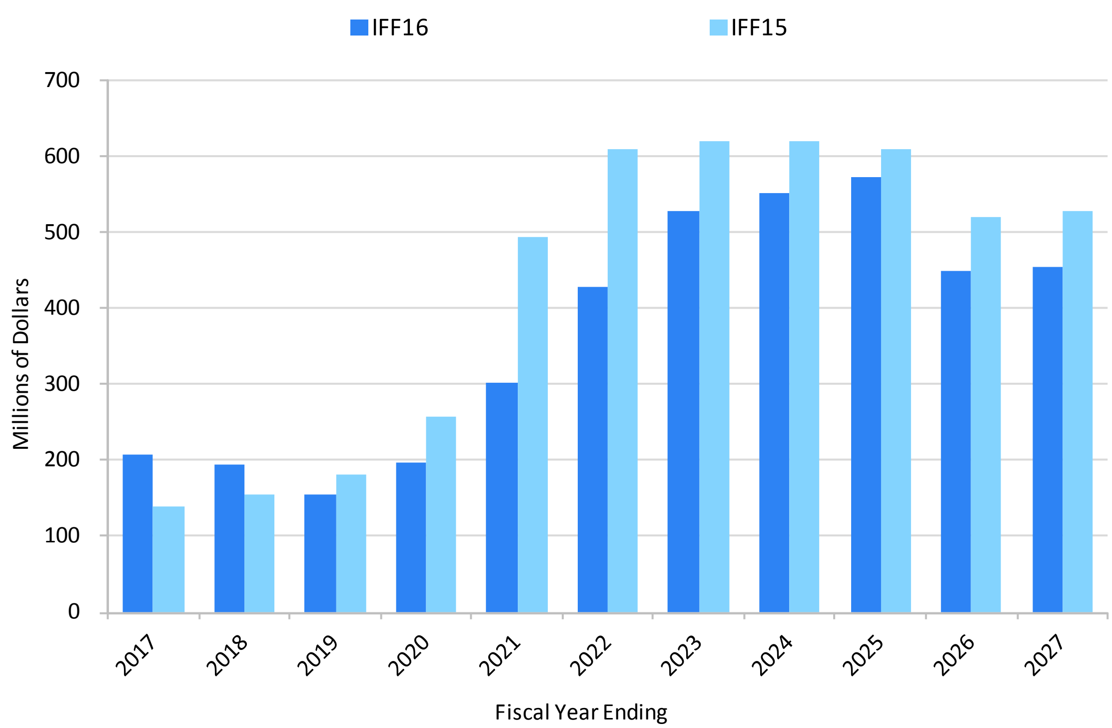
Manitoba Hydro signed a 100 MW Sale Agreement with Saskatchewan Power Corporation for twenty years commencing June 1, 2020 until May 31, 2040. The sale requires the construction of a new 230 kV interconnection with a minimum firm transfer capability of 100 MW. The SaskPower 100 MW sale is at a capacity factor of 57.1% (6x16).

Extraprovincial sales volumes are forecast for the first forecast year (2016/17) based upon the actual inflow conditions and reservoir and lake level elevations as of December 2016 with expected inflows through to the end of the fiscal year. These favourable reservoir and lake level elevations are projected to carry forward into 2017/18 and assume inflow conditions based on the average of 102 water flow records. For 2018/19 and subsequent years, the projections are determined by averaging the revenues using flow conditions for the past 102 years (1912/13 to 2013/14).

Over the 11-year forecast period, net extraprovincial revenues (extraprovincial revenue net of water rentals and assessments and fuel and power purchased) decreases approximately $0.7 billion compared to IFF15. The decrease in net extraprovincial revenues is mainly comprised of lower forecast electricity export prices result in a reduction to net extraprovincial revenue of approximately $1.1 billion. Lost surplus opportunity revenues from the delay in the Keeyask in-service further decreases net extraprovincial revenues by $0.5 billion. The decrease is partially offset by higher export volumes resulting from lower net Manitoba energy requirements, after planned additional DSM savings, of about $0.8 billion. MH16 also incorporates a reduction in transmission charges of about $0.1 billion associated with a plan to relinquish redundant firm point to point transmission reservations as they expire following the in-service of the new U.S. interconnection in 2020/21.

The following **Figure 5-1** shows the dampening effect of lower electricity export prices on IFF16 net extraprovincial revenues compared to IFF15.

Figure 5-1: Extraprovincial Revenues
(Net of Water Rentals and Assessments and Fuel and Power Purchased)



6.0 ELECTRICITY SUPPLY

Table 6-1 highlights the new resources committed to serve Manitoba Hydro's net firm energy requirements.

Table 6-1: Committed New Electricity Resources

Electricity Resources	MW	Dependable GW.h	In-Service Date	Projected Cost ($ Billions)
HVDC Bipole III Line & 2300 MW of Converter Capability	80	177	2018/19	5.0
Keeyask	695	3 000	2021/22	8.7
500 kV US Interconnection	698 import (883 export)	-	2020/21	MMTP 0.5
Demand Side Management Program				
Planned Additional	814	3 527	By 2030/31	1.1

Bipole III Reliability is needed to satisfy reliability requirements within Manitoba, and also results in reductions in transmission losses prior to new northern generation. Bipole III Reliability, routed on the west side of lakes Manitoba and Winnipegosis, continues to be planned for a 2018/19 in-service date.

Bipole III Reliability does not provide any new generation, but is expected to reduce the transmission losses which currently occur on the HVDC system. By using all three bipoles to transmit the generation from the lower Nelson River plants, rather than just the existing two bipoles, the losses are reduced and result in 80 MW and 177 GWh/year of reduced losses under drought conditions. This benefit has been included and is adjusted downward as new northern hydroelectric generation increases the loading.

The Keeyask generating station will be located upstream of the Kettle generating station on the lower Nelson River with seven units having a maximum rated total power capacity of 695 MW, which occurs when Stephens Lake is drawn down. There will be a net addition of 630 MW to Manitoba Hydro's Integrated Power System once the Keeyask generating station is added.

Construction of the Keeyask project began in July 2014, following receipt of all required provincial and federal licenses, authorizations and permits. The control budget and schedule for Keeyask were updated in March 2017 with a revised cost of $8.7 billion and a planned first unit in-service of August 2021, a 21-month delay compared to IFF15.

The new 500 kV U.S. interconnection will be capable of providing firm transmission service of 698 MW for imports and 883 MW for exports. The new interconnection is assumed to have an in-service date of June 1, 2020 which is coincident with the start of the related long-term contracts with Minnesota Power. The new interconnection requires several Canadian and U.S.

regulatory approvals which are expected to be received by mid-2017. The new interconnection consists of two separate 500 kV transmission line projects. In Canada, the Manitoba Minnesota Transmission Project (MMTP) will run 213 km from the Dorsey station and will be constructed and owned by Manitoba Hydro. In the U.S., the Great Northern Transmission Line Project (GNTL) will run 224 miles (360 km) from the U.S./Canada border into the new Blackberry substation near Grand Rapids, Minnesota, and will be constructed and owned by Minnesota Power.

DSM is discussed in **Section 4.0** of this report.

Manitoba Hydro's 2016/17 Resource Planning Assumptions & Analysis (RPAA) determined that no new resources are needed in timeframe of this forecast. The RPAA indicates new thermal resources are required by 2036/37 to meet persistent capacity and energy shortfalls under dependable energy conditions. From 2033/34 to 2035/36, there are projected short-term capacity deficits which are assumed to be met through market purchases.

With the MH16 adjustment to the 2016 Load Forecast the need for new resources is further delayed to 2040/41.

7.0 OPERATING & ADMINISTRATIVE EXPENSE

Operating & administrative (O&A) expenses in IFF16 include those expenditures necessary to provide for the safe and reliable operation and maintenance of the generation, transmission and electric and gas distribution systems. O&A expenses are comprised primarily of labour and benefits, materials, contracted services and overhead costs associated with operating and maintaining all facilities of the Corporation and providing services to customers.

In MH15, Manitoba Hydro limited increases in O&A for 2015/16 to 2021/22 to below inflationary levels at 1%, excluding the impacts of accounting changes. In order to be able to meet this level of O&A, Manitoba Hydro committed to reducing approximately 330 operational positions over the period 2014/15 to 2016/17. As of December 31, 2016, Manitoba Hydro had exceeded this target and achieved a cumulative reduction of 428 operational positions through attrition, the application of technology, and consolidation and elimination of work processes where appropriate.

MH15 also incorporated O&A savings attributable to the Supply Chain Management Initiative. The initiative targeted to realize savings on goods and services purchased, reduce or avoid operating costs, and reduce capital expenditures. This initiative began in 2014/15 and has continued throughout 2015/16 and 2016/17 with particular focus on:

- reducing excess inventory,
- implementing automatic replenishment,
- transitioning to strategic sourcing methods,
- optimizing staff levels with respect to Haulage Services,
- implementing stronger category management practices for procurement,
- optimizing material distribution networks,
- improving governance for the inventory of critical spares,
- improving forecasting and planning for inventory management,
- optimizing vehicle fleet levels, and
- improving the repair, maintenance and fuel supply networks for fleet vehicles.

The initiative has resulted in accumulated realized savings to date totaling approximately $8 million related to air travel, administrative expenses, maintenance, and upgrade costs.

As part of the Corporation's current plan to strengthen Manitoba Hydro's long-term financial health, further significant cost reductions have been incorporated in the O&A targets embedded in IFF16. These reductions are expected to be achieved through additional internal workforce reductions and procurement savings obtained through the Supply Chain Management Initiative.

<u>Workforce Reductions</u>

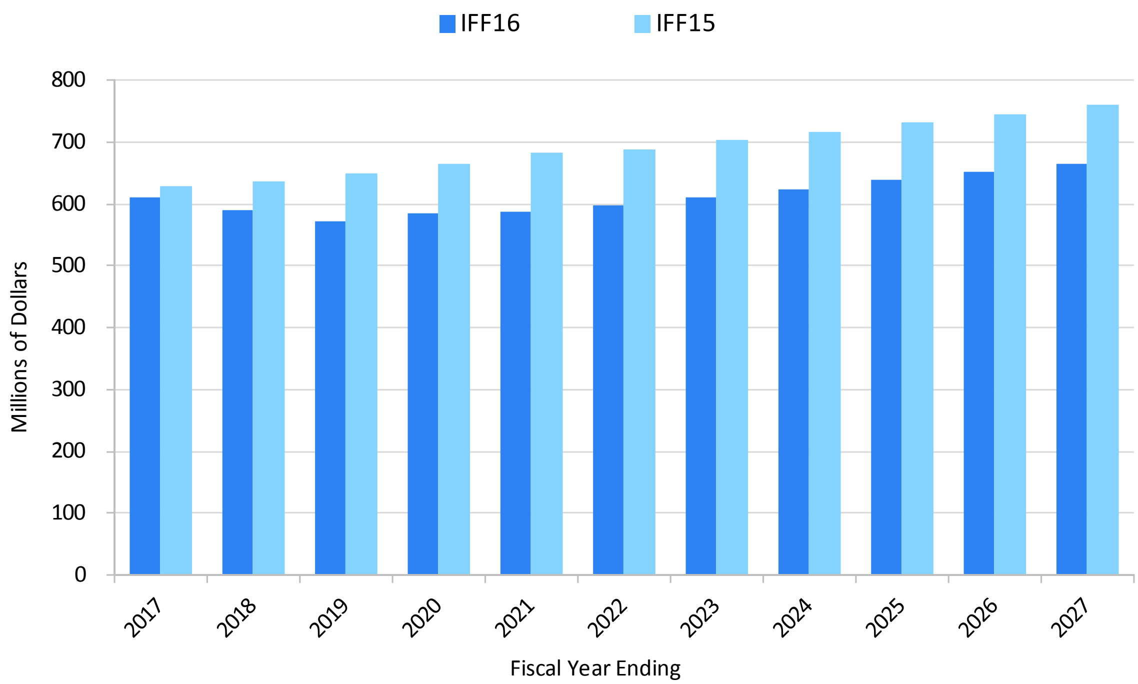
Manitoba Hydro has committed to deliver significant incremental cost reductions. Execution of the cost reduction plan began in February 2017 when Manitoba Hydro announced a plan to reduce its total workforce by 15% or 900 positions and began by reducing the executive leadership team by 30%, as well as reducing the number of direct reports to the Vice-Presidents by 40%. At the same time, the Voluntary Departure Program launched, targeting to achieve the remaining 900 position reductions. The target 900 positions are projected to be eliminated over the next five years for cumulative additional savings of approximately $900 million by the end of the 10-year forecast period to 2026/27. IFF16 assumes that approximately $700 million are operational savings and the remaining $200 million are related to capital.

<u>Procurement Savings</u>

In addition to position reductions, Manitoba Hydro has committed to achieve additional procurement savings obtained through the Supply Chain Management Initiative. Manitoba Hydro is working with a consulting firm to accelerate supply chain management initiatives which have been underway since 2014/15 (as discussed above). From 2017/18 to 2020/21, potential cost savings of $150 million have been identified through a variety of strategic sourcing opportunities using industry specific indices (approximately 70% related to capital reductions and the remaining 30% to operational reductions). Categories include construction and infrastructural services, building and facility construction, contractor and professional services, general hardware, fleet assets and repair, and building material and structures. Strategies for sourcing savings within these categories include amalgamation of contracts to capitalize on volume discounts; optimizing total cost of ownership; rationalizing services through identification of discretionary and critical services; specification refinement/rationalization; and reduction of single source contracts through competitive tenders. By the end of the 10-year forecast period to 2026/27, these savings are expected to accumulate to nearly $450 million.

Figure 7-1 below shows the O&A expense in IFF16 and IFF15. O&A savings discussed above are partially offset by inflationary increases assumed for net wages, salaries, and benefits.

Figure 7-1: Operating and Administrative Expenses

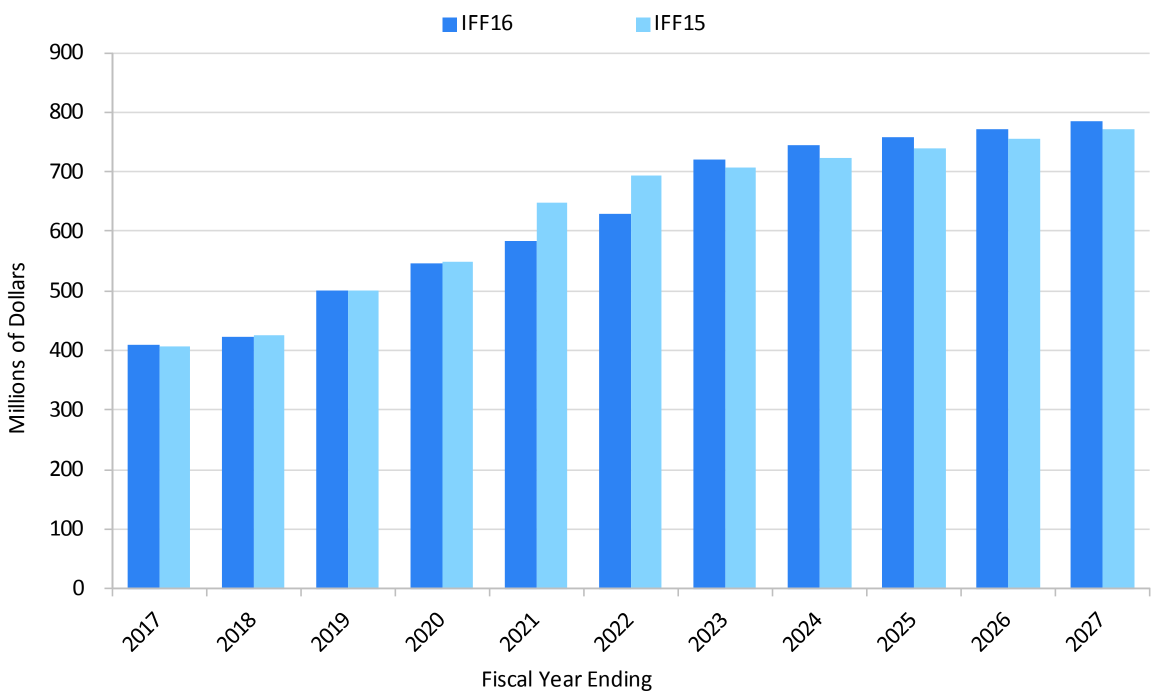


8.0 DEPRECIATION & AMORTIZATION EXPENSE

The depreciation and amortization expense included in IFF16 is based on a comprehensive depreciation study that was completed in October 2014.

Figure 8-1 below provides a comparison of the depreciation and amortization expense between IFF16 and IFF15. Depreciation and amortization expense over the 11-year forecast period decreases less than $100 million compared to IFF15. This is due mainly to the increase in Bipole III Reliability and Keeyask depreciation being offset by the delay in Keeyask in-service, and consequently the delay in depreciation being charged to net income.

Figure 8-1: Depreciation and Amortization Expense

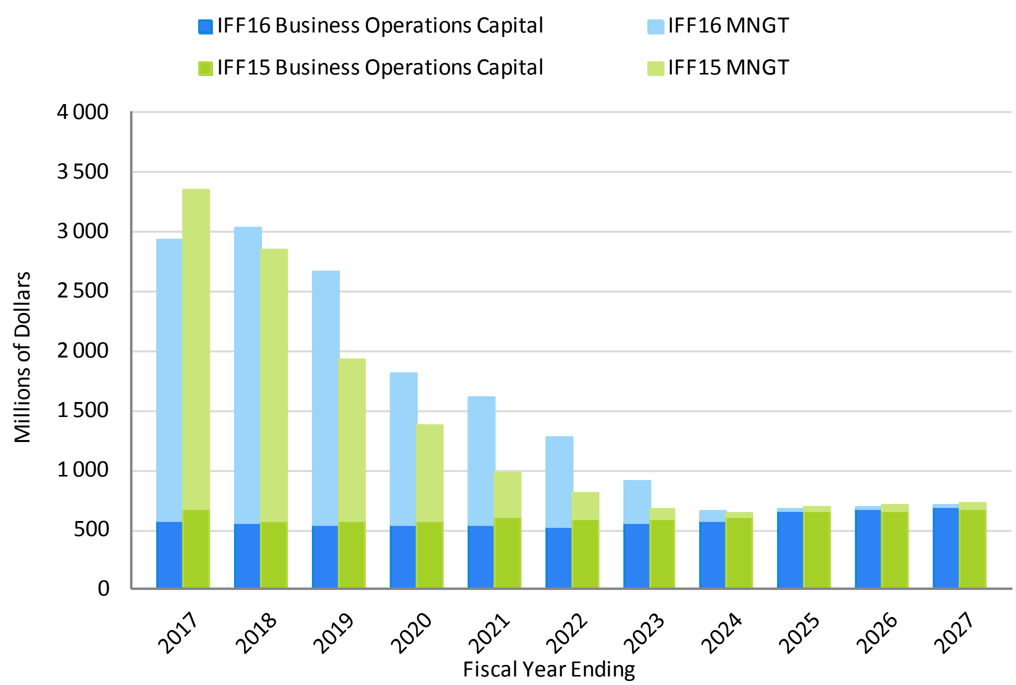


9.0 CAPITAL EXPENDITURE FORECAST & DEMAND SIDE MANAGEMENT FORECAST (CEF16)

CEF16 is a projection of Manitoba Hydro's capital expenditures for new and replacement facilities to meet the electricity and natural gas service requirements in the Province of Manitoba as well as expenditures required to meet firm sale commitments outside the province. Expenditures included in CEF16 will provide for an ongoing safe and reliable supply of energy in the most efficient and environmentally sensitive manner. CEF16 also includes a projection of Manitoba Hydro's DSM programs which provide education, incentives, and expertise to achieve energy savings to offset growing demand.

Figure 9-1 below shows projected CEF16 capital expenditures compared to CEF15.

Figure 9-1: Capital Expenditure & DSM Forecast (CEF16)



CEF16 including DSM totals $14.9 billion for the 10-year period from 2017/18 through 2026/27. Expenditures for MNG&T total $8.1 billion, with the balance of $5.9 billion comprised of expenditures for infrastructure renewal, system safety and security, new and increasing load requirements and ongoing efficiency improvements. DSM expenditures total $0.9 billion for the same period.

Table 9-1 shows the CEF16 project increases and decreases over the 10-year forecast period as compared to CEF15:

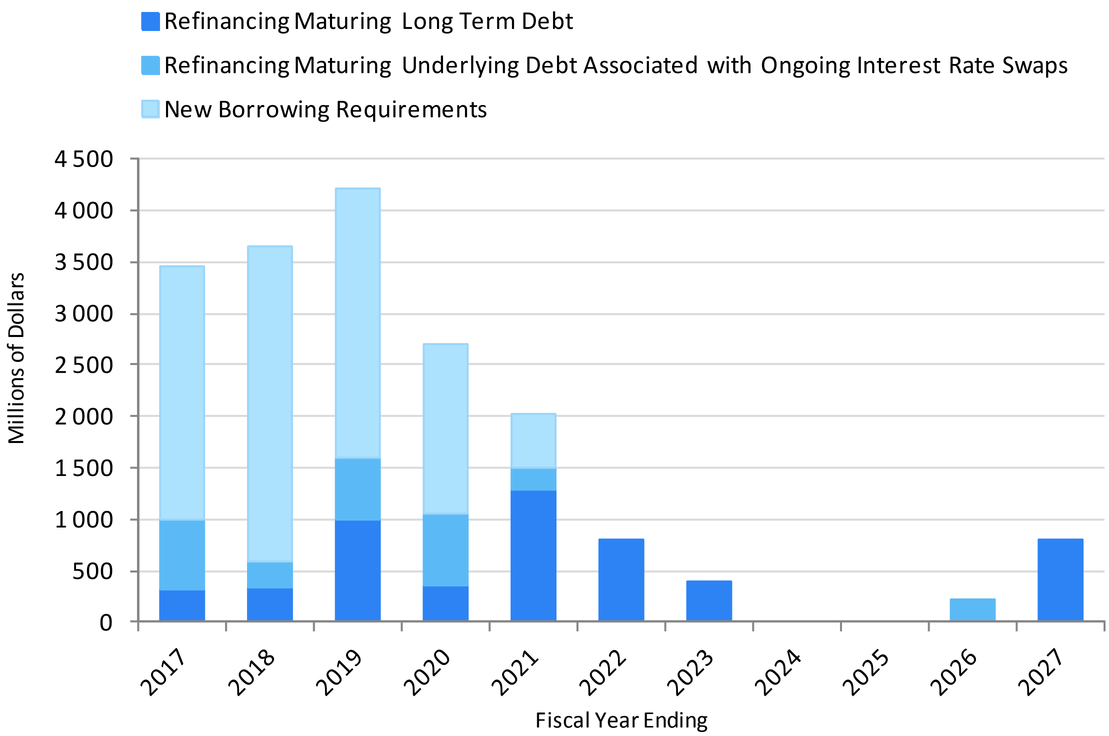
Table 9-1: Summary of CEF16 Project Increases / (Decreases)

	Total Projected Cost	Total Projected Cost Increase (Decrease)	10 Year Increase (Decrease) 2018 to 2027
	($ Millions)		
Keeyask - Generation	8 726	2 230	2 505
Bipole III Reliability	5 042	389	835
Manitoba-Minnesota Transmission Project	453	100	113
Generating Station Improvements & Upgrades	NA	NA	(256)
Target Adjustment for MNG&T	NA	NA	(293)
Other MNG&T Projects	NA	NA	(59)
Business Operations Capital	NA	NA	(236)
Electric Demand Side Management	NA	NA	(90)
Gas Demand Side Management	NA	NA	15
			$ 2 532

10.0 BORROWING REQUIREMENTS

Manitoba Hydro's forecast consolidated borrowing requirements are shown in **Figure 10-1** as follows.

Figure 10-1: Projected Consolidated Borrowing Requirements



Manitoba Hydro arranges long-term financing in the form of advances from the Province of Manitoba. Both long and short-term borrowings are guaranteed by the Province (except for mitigation bonds issued by the MHEB). Manitoba Hydro's interest rate policy on its existing debt portfolio is to limit the aggregate of: i) floating rate debt, ii) short-term debt, and iii) fixed rate long-term debt to be refinanced within the subsequent 12-month period; to a maximum of 35% of the total debt portfolio. During years in which there are high levels of refinancing and/or new borrowings for prospective cash requirements, in order to manage the overall interest rate risk profile, the Corporation's interest rate risk on its existing debt portfolio may be reduced by decreasing the percentage of aggregated floating rate debt and short-term debt to below 10% of the total debt portfolio.

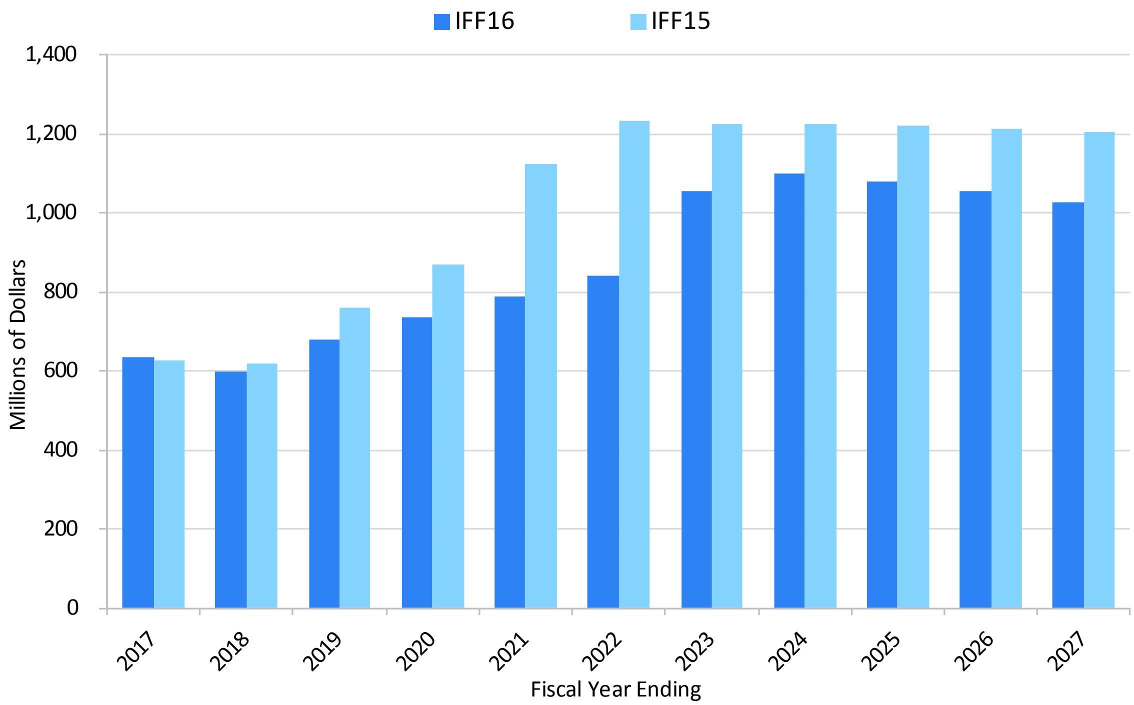
From 2016/17 to 2019/20, projected consolidated borrowing requirements are predominantly related to new financing resulting from planned capital expenditures for MNG&T projects. With the forecast availability of cash in the early 2020s, an opportunity exists to use this cash to retire debt at its maturity. Given the potential availability of future cash flows, Manitoba Hydro may be able to issue shorter dated debt maturities, which in an upwardly sloped yield curve would have lower yield rates – thereby reducing finance expense and keeping the weighted average interest rate of the debt portfolio relatively stable during a period of forecasted rising interest rates. The increase in cash flow in IFF16 over previous plans allows for debt retirement which is a key factor towards the planned reduction in finance expense and the recovery of Manitoba Hydro’s financial ratios.

11.0 FINANCE EXPENSE

Finance expense is projected to be the largest cost component on the financial statements, representing approximately one third of total projected expenses over the 10-year forecast period. Projected finance expense is expected to double over the IFF16 forecast period, due mainly to the borrowing requirements arising from Manitoba Hydro's capital investment program.

Figure 11-1 below compares finance expense between IFF16 and IFF15.

Figure 11-1: Finance Expense



Over the next ten years, Manitoba Hydro plans to shorten the average term to maturity of new debt issuances and thereby further reducing the debt portfolio's weighted average interest rate and the overall debt servicing costs. The financial benefit associated with this forecasting assumption change has the potential to provide approximately a $185 million reduction in debt servicing costs over the next five years to the end of 2021/22 and approximately $500 million by the end of the 11-year forecast period to 2026/27.

In comparison to IFF15, finance expense in MH16 is $1.7 billion lower in the 11-year period to 2026/27 due to the extended period of deferred financing charges associated with the 21-month Keeyask delay through interest capitalization ($0.6 billion); lower forecasted interest rates ($0.5 billion); a plan to shorten the average term to maturity for new debt issuance from 20 to 12 years ($0.5 billion); as well as lower finance expense on lower debt volumes associated with projected higher rate increases and savings from Manitoba Hydro's cost reduction program and the beneficial reduction in the compounding of lower debt service costs ($0.8 billion). These reductions to finance expense are partially offset by the increase in projected borrowing and interest payments associated with the increase in major capital project costs ($0.7 billion).

12.0 NET MOVEMENT

The balances arising in net movement consist of additions to regulatory deferral balances on an annual forecast basis. The recovery/reversal consists of amounts recovered from customers through the amortization of existing regulatory balances or rate riders. The net impact of these transactions results in the net movement deferral balances. A positive net movement balance adds to net income, while a negative balance will subtract from net income.

The regulatory deferral debit balances of the Corporation consist of the following:

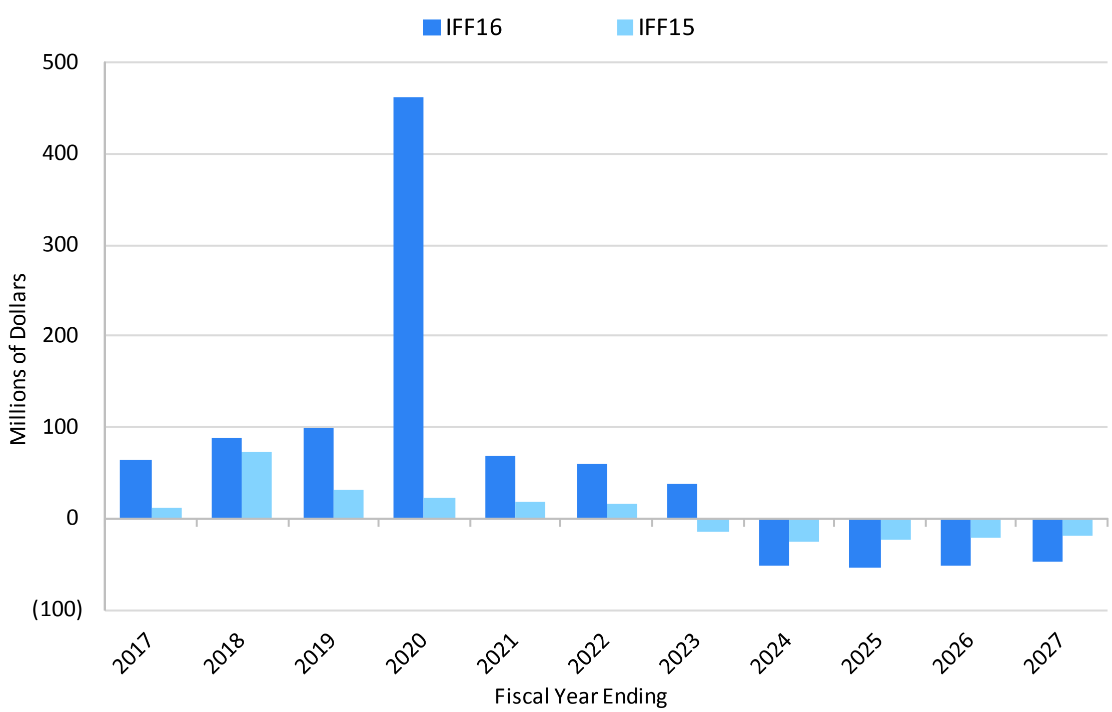
- DSM expenditures are incurred for energy conservation programs to encourage residential, commercial and industrial customers to use energy more efficiently.
- Site restoration expenditures are incurred for the remediation of contaminated corporate facilities and diesel generating sites.
- Change in depreciation method represents the cumulative annual difference in depreciation expense between the ASL method of depreciation as applied by Manitoba Hydro prior to its transition to International Financial Reporting Standards (IFRS) and the Equal Life Group (ELG) method as applied by Manitoba Hydro under IFRS.
- Deferred ineligible overhead is the cumulative annual difference in overhead capitalized for financial reporting purposes under IFRS and overhead capitalized for rate setting purposes.
- Acquisition costs relate to costs associated with the acquisition of Centra Gas and Minell (July 1999) and Winnipeg Hydro (September 2002).
- The Affordable Energy Fund relates to future DSM expenditures in connection with The Winter Heating Cost Control Act. The intent of the Affordable Energy Fund is to provide funding for projects that would not otherwise be funded by Power Smart programs.
- Loss on disposal is the net asset retirement loss on plant assets retired from service.
- Regulatory costs are those incurred as a result of electric and gas regulatory hearings.
- Deferred taxes are the taxes paid by Centra Gas (July 1999) as a result of its change to non-taxable status upon acquisition by Manitoba Hydro.
- The expensing of Conawapa construction in progress costs in 2019/20.
- Meter rate change is the cumulative difference in gas meter depreciation based on a timeline of 20 years for financial reporting purposes and 25 years for rate setting purposes.

The regulatory deferral credit balances of the Corporation consist of the following:

- Purchased gas variance accounts are maintained to recover/refund differences between the actual cost of gas and the cost of gas incorporated into rates charged to customers as approved by the PUB. Purchased gas variance accounts are reflected as a regulatory debit or credit depending on whether the amounts represent a recovery from or a refund to the customers, respectively.
- Impact of 2014 depreciation study represents the cumulative unamortized difference in depreciation between the ASL method based on the 2010 depreciation study and the ASL method based on the 2014 depreciation study. The PUB requires the use of 2010 ASL depreciation rates for Centra Gas for rate setting purposes pending review at the next gas GRA.
- DSM deferral that represents the differences between actual and planned spending on electric and gas DSM programs in accordance with Orders 43/13 and 85/13. The cumulative differences have been recorded as a regulatory deferral account credit balance with an offsetting balance recorded as a regulatory deferral debit balance.

Net regulatory deferral balances reach a total of $1.3 billion by 2022/23. The following **Figure 12-1** compares net movement between IFF16 and IFF15.

Figure 12-1: Net Movement



Net movement balances revert to negative impacts on net income after fiscal year 2022/23 when ineligible overhead and the change in depreciation methodology are no longer added to the deferred balances.

13.0 WUSKWATIM POWER LIMITED PARTNERSHIP

The Wuskwatim Power Limited Partnership (WPLP) operates and maintains the Wuskwatim generating station and Manitoba Hydro purchases all of the generation under the terms of the Wuskwatim Project Development Agreement (PDA) signed by Manitoba Hydro and Nisichawayasihk Cree Nation (NCN) in 2006. NCN has contributed nearly $22 million and acquired, the maximum 33% common unit ownership interest in the WPLP, per the terms in the PDA.

WPLP's income statement is consolidated with Manitoba Hydro's electric operations income statement reflecting 100% of the partnership revenues and costs in each income statement line item. NCN's share of WPLP net income or losses are represented as non-controlling interest (shown as a deduction or addition before net income, respectively). The partnership's net assets are offset by an amount for NCN's non-controlling equity interest on Manitoba Hydro's balance sheet.

Compared to IFF15, WPLP is showing higher projected net earnings in IFF16 due to higher revenues associated with the higher domestic revenue rate increase impact on the energy price and favourable finance expense changes. The increase in earnings is partially offset by unfavourable U.S. export prices. As a result, non-controlling interest on Manitoba Hydro's income statement is higher throughout the forecast.

14.0 KEEYASK HYDROPOWER LIMITED PARTNERSHIP

The Keeyask Cree Nations (KCNs), including Tataskweyak Cree Nation and War Lake First Nation (operating together as Cree Nation Partners), Fox Lake Cree Nation and York Factory First Nation, have the right to acquire up to 25% in the Keeyask Hydropower Limited Partnership (KHLP). The partnership will construct, operate and maintain the Keeyask generating station and Manitoba Hydro will purchase all of the generation under the terms of the Joint Keeyask Development Agreement (JKDA) signed by Manitoba Hydro and the KCNs in 2009. The KCN have jointly contributed $2.25 million to date to acquire a 17.5% common ownership interest with an option to contribute additional capital in the future to activate an additional 7.5% in partnership units.

IFF16 assumes the KCNs will hold a 17.5% common ownership interest up to the in-service of the final Keeyask generating unit and then elect to invest in the preferred ownership option. Projected preferred distributions to the KCNs are recognized as an expense in water rentals and assessments.

KHLP's income statement is consolidated with Manitoba Hydro's electric operations income statement reflecting 100% of the partnership revenues and costs in each income statement line item. The partnership's net assets are offset by an amount for the KCNs' non-controlling equity interest on Manitoba Hydro's balance sheet.

Similar to the WPLP, unfavourable U.S. export prices are resulting in lower KHLP net earnings and preferred distributions relative to IFF15.

15.0 NATURAL GAS DEMAND & 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 95% of customers representing approximately 64% of volumes purchase their primary gas requirements from Manitoba Hydro, with the balance using brokers and marketers through the Western Transportation Service.

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

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

The 2016 Natural Gas Volume Forecast projects a 1% decrease in volume in 2025/26 as compared to last year's forecast driven primarily by residential customers, whose customer count and average use are projected to be lower. Lower average use continues to be driven by a higher occurrence of high efficiency furnaces, improved insulation levels, and conversions to electric water heaters.

CGM16 incorporates non-gas rate increases as required effective August 1 to generate net income of approximately $3 million. Proposed rate increases may be changed in future forecasts and are presented for illustrative purposes only. The gas forecast projects its first rate increase of 1.00% in 2020/21 followed by 1.50% in 2022/23, 1.25% in 2023/24, 1.00% in 2024/25, and 1.75% in 2026/27.

In Order 108/15 flowing from Centra's 2015/16 Cost of Gas Application, the PUB indicated that the non-gas cost revenue requirement needs to be reviewed in the context of the next GRA, to be filed by no later than January 20, 2017. In the absence of a Gas GRA, the 1.00% domestic revenue increase previously approved by the PUB following the 2013/14 Gas GRA would be reversed effective August 1, 2017. Manitoba Hydro advised the PUB that it would not be in a position to file a Gas GRA by January 20, 2017. As such, CGM16 assumes that the non-gas component of rates will revert back to levels previously approved by the PUB prior to the 2013/14 Gas GRA effective August 1, 2017, resulting in a reduction of $3-4 million in annual domestic revenue.

The gross margin forecast incorporates the most recently approved primary gas rates at August 1, 2016 and non-primary gas rates at November 1, 2015 as well as future load requirements as projected in the 2016 Natural Gas Volume Forecast.

MH16 includes a regulatory deferral account reflecting the difference between depreciation calculated using the ELG depreciation method for financial reporting purposes and the ASL method used for rate-setting purposes. In Order 73/15, the PUB directed Manitoba Hydro to continue to use the CGAAP ASL method of depreciation for rate setting purposes until the PUB is satisfied that a change in depreciation methodology is warranted. As Manitoba Hydro uses the ELG depreciation method for financial reporting purposes, MH16 assumes that the differences between these depreciation methodologies will accrue to a regulatory deferral account until March 31, 2023, the fiscal year end of the last Keeyask unit in-service.

CGM16 mirrors the assumption of the electric forecast in that amortization of these regulated assets will commence midway through 2017/18 and deferrals will continue until the last unit of Keeyask is in service in 2022/23. These deferrals are amortized over a five-year period.

16.0 FINANCIAL TARGETS

Manitoba Hydro has three primary financial targets which are used to assess the financial strength of the Corporation. These targets have been revised since the last GRA, having been recently reviewed both internally as well as by an external consultant in 2015:

MEASURE	TARGET
Equity Ratio	Maintain a minimum ratio of 25%
Interest Coverage	Maintain a minimum ratio of greater than 1.80
Capital Coverage	Maintain a ratio of greater than 1.20 (excepting MNG&T)

The first is to maintain a minimum equity ratio of 25%, a measure of the portion of assets that are financed by internally generated funds rather than debt. The second is an earnings before interest, taxes, depreciation and amortization interest coverage ratio with a minimum target of greater than 1.80, which measures the ability to meet interest payment obligations with cash flow. The third is to maintain a capital coverage ratio of greater than 1.20, which is a measure of the ability of cash flow from operations to fund sustaining capital expenditures. As the Corporation continues through a phase of unprecedented investment, Manitoba Hydro recognizes the overstatement of the capital coverage ratio due to the omittance of the capitalized interest on major capital expenditures.

Manitoba Hydro's financial targets were originally set in 1995 after an internal and external consultant review. Since that time, these targets have been internally reviewed and periodically enhanced. Recognizing that the current investments in MNG&T and existing infrastructure would place considerable pressure on Manitoba Hydro's key financial ratios, it was important that Manitoba Hydro's financial targets be once again reviewed externally.

In November 2014, KPMG was retained to provide recommendations with respect to appropriate financial targets which align with the mandate of Manitoba Hydro and the interests of its stakeholders considering its operating and business outlook and associated risks.

KPMG's financial target recommendations considered: the objectives of maintaining rate stability for customers while at the same time maintaining safe and reliable service; the period of significant capital investment and infrastructure renewal that Manitoba Hydro is entering into; and the maintenance of Manitoba Hydro's self-supporting status for credit rating purposes. The scope of work did not extend to reviewing broader policy questions associated with overall structure, governance framework, and business strategy and plans.

Key factors and observations that influenced KPMG's recommendations are as follows:

- Relative to other Crown utilities with a significant base of hydro-electric generation, Manitoba Hydro faces a number of heightened risks including a larger capital investment program, greater hydrology risks, significant reliance on export revenues, and higher assets and debt on a per capita basis compared to other jurisdictions. These risks suggest that Manitoba Hydro should have financial targets that provide a significant amount of equity cushion.
- Manitoba Hydro's target equity ratio is at the low end of those maintained or forecast by other power utilities and a number of those utilities plan to strengthen their financial ratios in the longer term.
- Loss of self-supporting status would have detrimental effects on the Province and the utility. Uncertainty with respect to when self-supporting status would be lost suggests that financial targets should err on the side of caution.
- Additional rate increases in the early years of the forecast horizon can result in a significant improvement in Manitoba Hydro's financial metrics in later years reducing the impact of interest compounding on the additional debt that is required when rate increases are lower.
- Manitoba Hydro has limited ability to restrain a drop in financial ratios during adverse conditions such as drought which highlights the risk of having an equity ratio that approaches 10%.
- Manitoba Hydro's capital investment program is characterized by periodic "bumps" or "hills" of large magnitude which magnify the challenges associated with Manitoba Hydro's limited levers with which to adjust its equity cushion.
- Manitoba Hydro will need to depart from its equity target during major build programs: this reflects the utility's limited financing tools and reliance on retained earnings as its dominant source of equity. Accordingly, the equity position should rise above 25% in advance of major build programs to mitigate the deviations from target that are observed.
- In the long-term, with respect to deviations from any target, it would be desirable to limit decreases in the equity ratio to 5-10 percentage points.
- Government guarantees enable government-owned utilities such as Manitoba Hydro to have lower equity ratios in their capital structure and to have lower financial metrics than averages observed for investor-owned utilities.

KPMG's overall finding was that the current financial targets used by Manitoba Hydro are appropriate. The following is a summary of KPMG's key findings and recommendations to Manitoba Hydro:

Debt/Equity: The current debt to equity ratio of 75:25 is a reasonable long-term target but 70:30 would provide additional financial strength and address unique financial challenges and risks. KPMG recommended that the debt to equity ratio in the long-term should fall within the range of 75:25 to 70:30. KPMG also suggested that it would be desirable to maintain a minimum equity ratio near 15% during major capital expansions.

Interest Coverage: If Manitoba Hydro continues with the current EBIT (earnings before interest and taxes) interest coverage ratio, a minimum target of 1.20 is reasonable. KPMG recommended Manitoba Hydro adopt an EBITDA (earnings before interest, taxes, depreciation and amortization) interest coverage ratio with a minimum target of 1.80 or greater.

Capital Coverage: The capital coverage ratio is a unique and important financial target to Manitoba Hydro. KPMG found that the current minimum target of 1.20 or greater is reasonable.

Following the completion of the KPMG review, Manitoba Hydro developed its financial target recommendations for the then MHEB taking into consideration the findings and recommendations of KPMG and an expanded uncertainty analysis undertaken by the Corporation.

The previous MHEB endorsed the following conclusions in December 2015:

- That the current debt/equity ratio target of 75:25 be retained as its long-term financial target.
- That it would be impractical to adopt a 70:30 target at this time due to further incremental revenue increases that would be required from domestic customers necessary to do so, and that it does not believe that maintenance of the 75:25 debt/equity ratio target places customers at undue risk of rate instability.
- That the adoption of a minimum debt/equity ratio of 85:15 was not prudent at this time.
- That an EBITDA interest coverage ratio with a minimum target of 1.80 be adopted to replace the current 1.20 EBIT interest coverage target.

- That the current capital coverage ratio with a minimum target of 1.20 (excepting MNG&T) be retained as it is an effective measure of the ability of the Corporation to generate sufficient cash to sustain its operations.

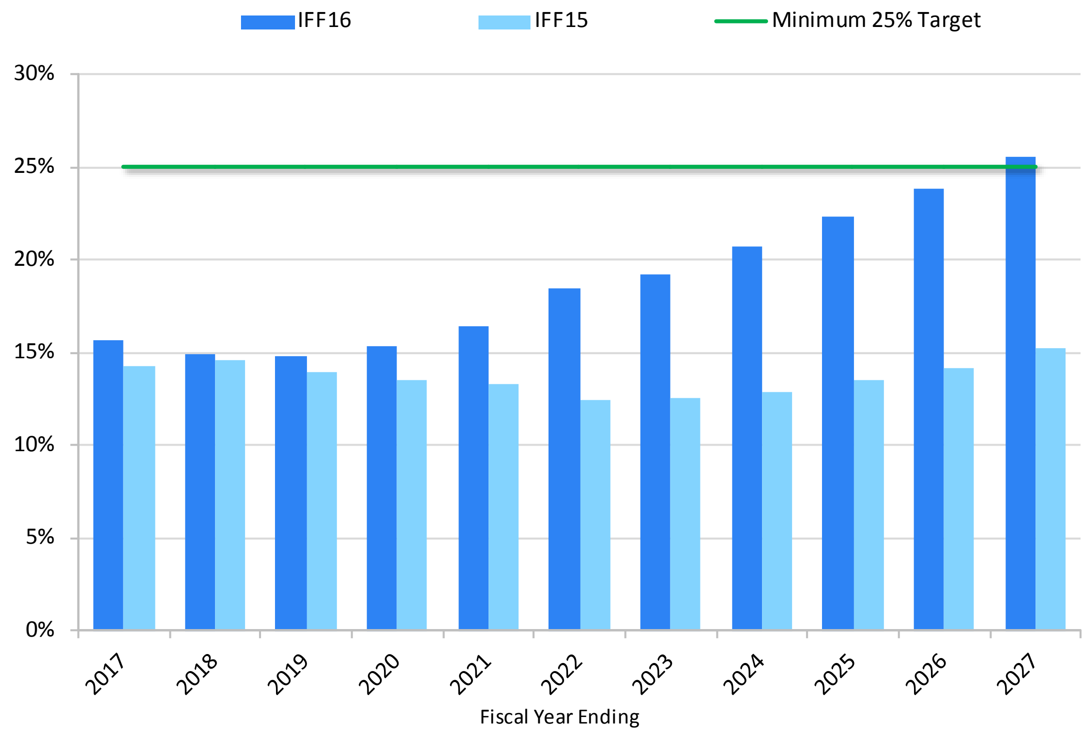
Since the last GRA and the November 2015 Supplemental Filing, a new Board of Directors (MHEB) has been appointed along with a new President & CEO and a new Chief Finance & Strategy Officer. Together, the MHEB and senior management team have charted a new course for Manitoba Hydro inclusive of a strategic imperative to restore financial sustainability. While overall minimum financial targets have not changed, Manitoba Hydro is of the view that previous financial plans were inadequate in that the time frame under which the Corporation reached financial health was unacceptable, leaving the Corporation at too high of a risk for too long. A path back to 25% equity of longer than ten years is, in the view of Manitoba Hydro, too risky.

16.1 Debt / Equity Ratio

Figure 16-1 below shows the projected consolidated equity ratio for IFF16 compared to IFF15.

High levels of capital investment over the first six years combined with lower projected revenues result in significant downward pressure on the equity ratio to 2021/22. Manitoba Hydro's accelerated cost reduction program, lower forecast interest rates, and the projected 3.95% rate increases from the previous plan on their own are not enough to change the trajectory of the equity ratio. The new MHEB's and senior management's tolerance for risk has changed considerably and therefore a path back to 25% equity of longer than ten years is, in the view of Manitoba Hydro, too risky. The equity ratio only begins shows recovery with the acceleration of the previous plan's 3.95% rate increases from the 2022/23 to 2028/29 timeframe into the first five years. Thereafter, rate increases can return to 2.00% inflationary increases and still achieve the target 25% equity ratio within the 10-year forecast period.

Figure 16-1: Projected Consolidated Equity Ratio

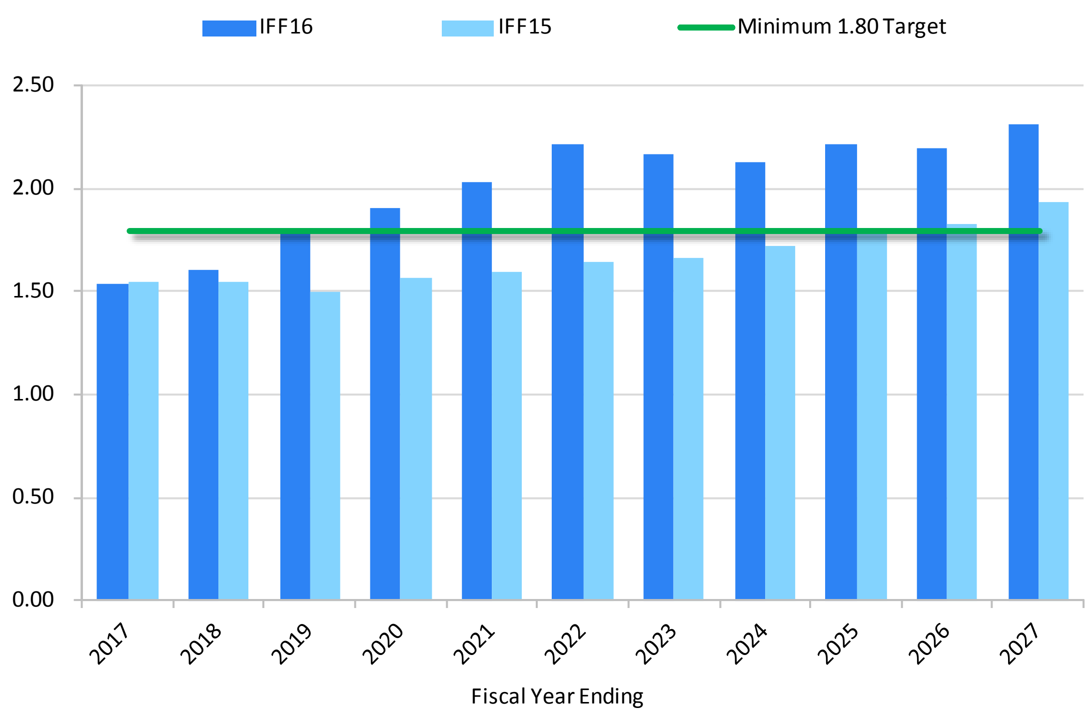


16.2 Interest Coverage Ratio

Figure 16-2 below shows the consolidated projected interest coverage ratio compared to the previous forecast IFF15 and target 1.80.

The EBITDA interest coverage ratio more closely reflects the ability of earnings to cover interest payment obligations that are not muted by deferred interest capitalized in projects. Capital investments in MNG&T place downward pressure on the interest coverage ratio until earnings supported by cost reductions and rate increases are sufficient to cover finance expenses to maintain the target level.

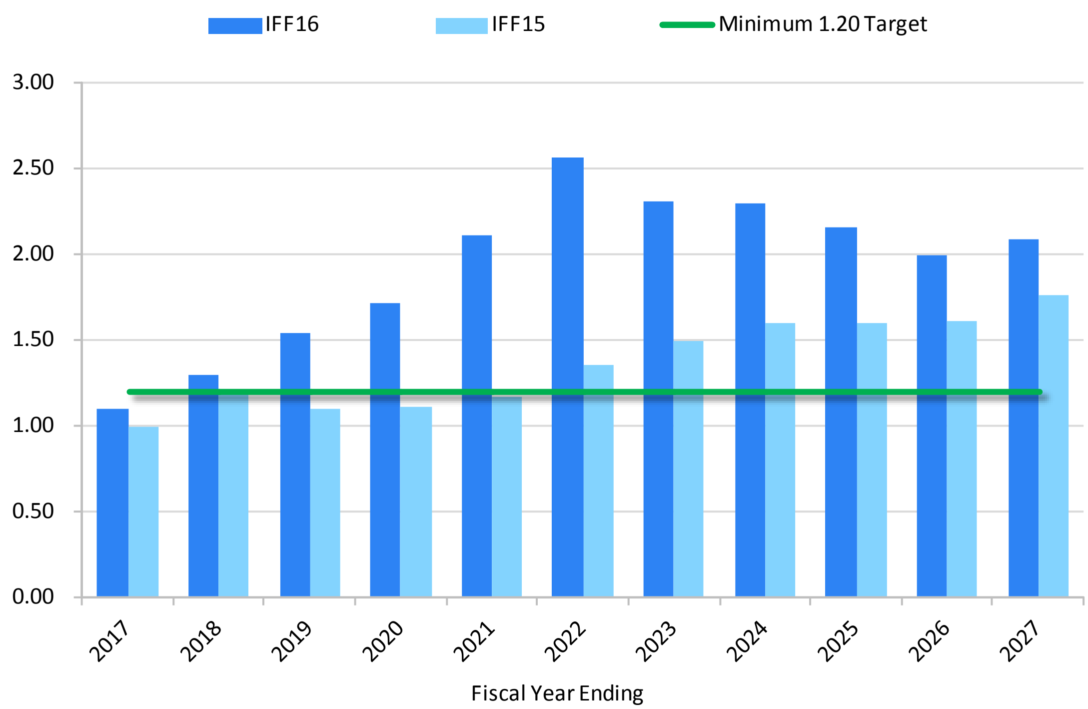
Figure 16-2: Projected Consolidated EBITDA Interest Coverage Ratio



16.3 Capital Coverage Ratio

Figure 16-3 below shows the comparative capital coverage ratios between IFF16 and IFF15. Compared to IFF15, the projected consolidated capital coverage ratio is higher due to higher internally generated funds attributable mainly to lower interest paid.

Figure 16-3: Projected Consolidated Capital Coverage Ratio



17.0 SENSITIVITY ANALYSIS

IFF16 includes a number of key assumptions as described in the previous sections. 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 flow conditions, and
- Rate increases.

The cumulative impacts to the MH16 electric operations retained earnings and the lowest equity ratio observed over the 10-year forecast period are shown in **Table 17-1** for each of the key changes in assumptions.

Table 17-1: Key Variable Sensitivity Impacts to MH16 Retained Earnings

	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	Lowest Equity Ratio in 10 yr Risk Scenario
Low Domestic Load Growth	(6)	(16)	(31)	(48)	(69)	(94)	(121)	(149)	(179)	14% (2019)
High Domestic Load Growth	17	46	107	175	250	331	418	508	600	15% (2019)
+ 1% Interest	(23)	(64)	(121)	(207)	(338)	(480)	(621)	(766)	(930)	14% (2019)
- 1% Interest	22	62	117	200	327	457	586	717	854	15% (2018)
C$/US$ Down 0.10 (C$ Strengthening)	13	16	20	16	(16)	(68)	(123)	(169)	(220)	15% (2019)
C$/US$ Up 0.10 (C$ Weakening)	(13)	(15)	(18)	(13)	17	63	111	150	194	14% (2018)
Low Export Price	(31)	(70)	(106)	(147)	(236)	(338)	(446)	(600)	(777)	14% (2019)
High Export Price	31	75	138	218	332	448	562	705	848	15% (2018)
5 Year Drought (starting in 2018/19)	(299)	(761)	(930)	(1 151)	(1 367)					12% (2020)
+ 1% Rate Increase in 2017/18	28	48	70	95	121	145	171	198	228	15% (2019)
- 1% Rate Increase in 2017/18	(27)	(46)	(68)	(92)	(119)	(150)	(182)	(215)	(253)	14% (2019)
$1B in Capital Overruns	(11)	(33)	(54)	(104)	(178)	(254)	(331)	(410)	(498)	14% (2019)
Capital Down $100 million/year	12	30	57	93	139	193	254	323	404	15% (2019)
Capital Up $100 million/year	(9)	(26)	(52)	(87)	(131)	(185)	(246)	(316)	(404)	14% (2019)

17.1 Domestic Load Growth Sensitivity

The 2016 Load Forecast is prepared assuming that there is a 50% chance that actual Manitoba energy requirements could be higher or lower than the 2016 Electric Forecast base case. To evaluate the potential variation in the load forecast due to long-term economic effects, 10% and 90% confidence bands were selected to represent proxies for the low and high load forecast scenarios. In comparison to the IFF16 base case, which adopted the 24th percentile load forecast as discussed in Section 3.0, the variability in gross firm energy in this sensitivity is -579 GWh and +1,991 GWh respectively by 2026/27.

17.2 Interest Rates Sensitivity

Interest rates assumed in IFF16 are projected to rise gradually over the first five years of the forecast. The interest rate sensitivity indicates the financial impacts of interest rates one percent higher or lower than forecast on short-term, long-term and floating rate debt, as well as sinking funds. During years in which there are high levels of refinancing and/or new borrowings for prospective cash requirements, in order to manage the overall interest rate risk profile, the Corporation's interest rate risk on its existing debt portfolio may be reduced by decreasing the percentage of aggregated floating rate debt and short-term debt to below 10% of the total debt portfolio.

17.3 Foreign Exchange Rates Sensitivity

The Canadian dollar is projected to be $1.30 (C$/US$) for 2016/17 strengthening to $1.15 by 2022/23. The exchange rate sensitivity indicates the financial impacts of the C$/U.S.$ exchange rate being $0.10 higher (C$ weakening) or lower (C$ strengthening) than forecast. In the short- to medium-term of the forecast, net income is largely inoculated from changes in the exchange rate due to the effective hedge provided by Manitoba Hydro's foreign currency exchange risk management program. In order to maintain an effective hedge, the U.S. debt portfolio may occasionally be rebalanced in accordance with U.S. dollar cash flows.

17.4 Export Prices Sensitivity

IFF16 reflects the reference electricity export prices derived from several independent price forecasts for the MISO region. Each price forecast consultant has their own electricity price forecast models, assumptions and view of the future. In preparing their forecasts, the consultants prepare their own internal estimates for a number of pricing factors. These factors include:

- Thermal fuel forecasts (coal and natural gas);

- Future load growth forecasts;
- Profile of existing generation (fuel type, efficiency and operating parameters);
- Profile of potential new generation (fuel type, efficiency, capital cost and required rates of return);
- Generation requirements;
- Power market rules; and
- Future regulation/legislation related to SO2 (sulfur dioxide), NOX (nitrous oxide), Hg (mercury) and CO2 (carbon dioxide) emissions, as well as cooling water releases and coal ash handling.

There is uncertainty in each of these factors, and particular uncertainty as to how future legislative requirements may evolve.

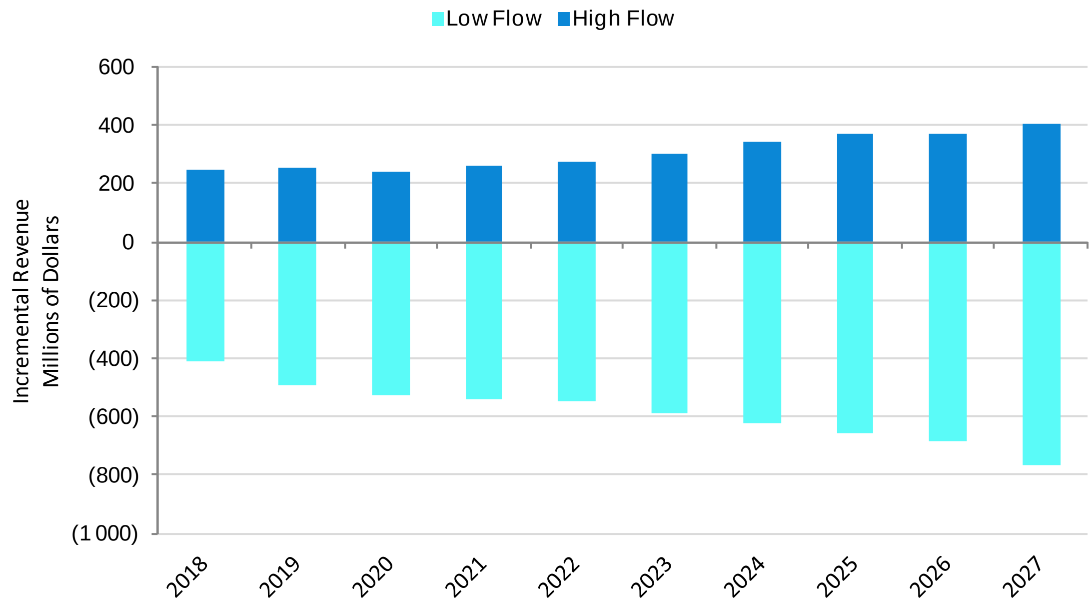
The low export price sensitivity was produced assuming 2016/17 export prices are held constant in real terms throughout the forecast period. The consensus reference export price forecast from the 2015 Electricity Export Price Forecast was used as a proxy for the high price sensitivity in IFF16.

17.5 Drought / Water Flow Sensitivity

IFF16 reflects the average revenues and expenses of 102 different potential system inflow conditions that occurred historically from 1912/13 to 2013/14. Although the forecast inherently includes the revenues and expenses associated with both the highest and lowest inflow conditions, the actual inflow could vary significantly from forecast in any given year as shown in **Figure 17-1**. The impact of low flows are greater than high flows due to the requirements for thermally generated and imported energy in low flow years and spilling of water beyond system constraints in high flow years.

Figure 17-1: Variability of Net Interchange Revenue

Compared to Average Revenue for All Flow Conditions



A prolonged period of low flows has a significant financial impact. The current estimate of a recurrence of the historic five-year drought from 1987/88 to 1991/92 is approximately $1.4 billion by the end of the drought period in 2022/23. This represents the deviation in net interchange revenues and generation costs if the five-year drought begins in 2018/19 compared to the average net revenues resulting from all historic flow cases. The costs of drought could rise under a scenario of higher electricity export and thermal fuel prices.

17.6 Rate Increase Sensitivity

Table 17-1 indicates the financial impact of a +/-1% change in the proposed electric rate increase in 2017/18.

17.7 Capital Expenditure Sensitivities

IFF16 includes two capital expenditure sensitivities: the first reflects the financial effects of $1 billion in cost overruns from the current approved control budgets for Bipole III Reliability and Keeyask; and the second reflects inflationary or deflationary changes to MNG&T and Business Operations Capital relative to general inflation levels and/or reduction or increases to expenditures necessary to meet reliability, regulatory or customer requirements.

18.0 PROJECTED CONSOLIDATED FINANCIAL STATEMENTS (IFF16)

CONSOLIDATED PROJECTED OPERATING STATEMENT (IFF16)
(In Millions of Dollars)

For the year ended March 31	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
REVENUES											
Domestic Revenue	1 858	2 015	2 198	2 328	2 484	2 653	2 713	2 776	2 842	2 903	2 971
BPIII Reserve Account	(96)	(119)	9	71	71	71	71	24	0	0	0
Extraprovincial	468	454	432	455	578	696	795	818	844	707	714
Other	83	92	97	99	102	104	105	107	109	110	112
	2 312	2 442	2 736	2 954	3 235	3 523	3 684	3 725	3 795	3 720	3 797
EXPENSES											
Cost of Gas Sold	192	228	228	228	228	228	227	226	225	225	224
Operating and Administrative	611	591	573	584	587	598	612	625	638	651	665
Finance Expense	650	612	701	762	815	871	1 092	1 116	1 102	1 078	1 045
Finance Income	(18)	(16)	(20)	(27)	(27)	(32)	(38)	(17)	(21)	(22)	(17)
Depreciation and Amortization	411	424	500	546	585	628	721	746	758	772	786
Water Rentals and Assessments	131	124	112	113	114	117	127	128	131	131	131
Fuel and Power Purchased	130	135	165	145	162	149	140	137	141	127	129
Capital and Other Taxes	134	149	162	172	179	183	192	193	193	194	194
Other Expenses	105	169	164	537	151	148	128	122	125	130	135
	2 345	2 417	2 585	3 059	2 794	2 892	3 201	3 277	3 293	3 287	3 292
Net Income before Net Movement in Reg. Deferral	(33)	25	151	(105)	441	631	483	448	502	433	505
Net Movement in Regulatory Deferral	64	88	100	463	69	60	38	(52)	(53)	(51)	(47)
Net Income	31	113	251	357	511	692	521	396	448	382	458
Net Income Attributable to:											
Manitoba Hydro	**44**	**122**	**252**	**355**	**506**	**683**	**512**	**385**	**446**	**380**	**455**
Non-controlling Interest	(12)	(9)	(1)	2	5	8	9	11	3	2	3
Additional Domestic Revenue											
General electricity rate increases	0.00%	7.90%	7.90%	7.90%	7.90%	7.90%	2.00%	2.00%	2.00%	2.00%	2.00%
General gas rate increases	0.00%	-1.00%	0.00%	0.00%	1.00%	0.00%	1.50%	1.25%	1.00%	0.00%	1.75%
Financial Ratios											
Equity	16%	15%	15%	15%	16%	18%	19%	21%	22%	24%	26%
EBITDA Interest Coverage	1.54	1.60	1.79	1.91	2.03	2.22	2.17	2.12	2.22	2.20	2.31
Capital Coverage	1.10	1.30	1.54	1.72	2.11	2.57	2.31	2.30	2.16	2.00	2.08

CONSOLIDATED PROJECTED BALANCE SHEET (IFF16)
(In Millions of Dollars)

For the year ended March 31	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
ASSETS											
Plant in Service	13 876	14 541	19 947	20 599	21 693	27 151	31 516	32 080	32 755	33 458	34 108
Accumulated Depreciation	(1 031)	(1 384)	(1 834)	(2 302)	(2 761)	(3 292)	(3 895)	(4 540)	(5 176)	(5 864)	(6 493)
Net Plant in Service	12 845	13 156	18 112	18 296	18 932	23 859	27 621	27 540	27 578	27 594	27 616
Construction in Progress	6 948	9 312	6 600	7 382	7 874	3 697	228	317	280	276	274
Current and Other Assets	1 568	1 758	2 140	2 326	2 125	1 811	1 641	1 839	2 006	1 752	1 948
Goodwill and Intangible Assets	344	558	798	941	1 343	1 297	1 251	1 206	1 163	1 120	1 078
Total Assets before Regulatory Deferral	21 705	24 785	27 651	28 946	30 274	30 664	30 741	30 902	31 027	30 742	30 915
Regulatory Deferral Balance	559	639	739	1 201	1 269	1 329	1 366	1 314	1 260	1 209	1 162
	22 264	25 424	28 390	30 147	31 543	31 993	32 108	32 216	32 287	31 952	32 077
LIABILITIES AND EQUITY											
Long-Term Debt	15 965	18 337	21 565	22 219	23 002	23 318	23 372	22 951	22 238	21 027	21 679
Current and Other Liabilities	3 466	3 957	3 375	4 116	4 258	3 731	3 301	3 458	3 785	4 268	3 275
Provisions	19	19	19	18	17	16	16	15	14	14	14
Deferred Revenue	448	464	492	522	544	555	567	578	589	600	612
BPIII Reserve Account	196	316	307	236	165	94	24	(0)	(0)	(0)	(0)
Retained Earnings	2 871	2 993	3 245	3 600	4 106	4 789	5 301	5 686	6 132	6 512	6 967
Accumulated Other Comprehensive Income	(761)	(714)	(665)	(616)	(600)	(562)	(522)	(521)	(520)	(520)	(520)
Total Liabilities and Equity before Regulatory Deferral	22 203	25 371	28 338	30 095	31 492	31 943	32 058	32 167	32 238	31 903	32 028
Regulatory Deferral Balance	61	53	52	52	51	50	49	49	49	49	49
	22 264	25 424	28 390	30 147	31 543	31 993	32 108	32 216	32 287	31 952	32 077
Net Debt	15 689	18 596	20 851	22 333	23 121	23 236	22 919	22 433	21 868	21 385	20 826
Total Equity	2 922	3 260	3 633	4 043	4 555	5 252	5 455	5 839	6 299	6 694	7 163
Equity Ratio	16%	15%	15%	15%	16%	18%	19%	21%	22%	24%	26%

CONSOLIDATED PROJECTED CASH FLOW STATEMENT (IFF16)

(In Millions of Dollars)

For the year ended March 31	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
OPERATING ACTIVITIES											
Cash Receipts from Customers	2 442	2 593	2 760	2 912	3 193	3 481	3 642	3 730	3 824	3 750	3 827
Cash Paid to Suppliers and Employees	(1 222)	(1 320)	(1 279)	(1 281)	(1 306)	(1 313)	(1 330)	(1 347)	(1 366)	(1 366)	(1 381)
Interest Paid	(586)	(547)	(648)	(715)	(758)	(819)	(1 036)	(1 066)	(1 059)	(1 042)	(1 000)
Interest Received	7	5	12	21	17	17	9	8	14	14	10
	641	730	845	937	1 145	1 365	1 285	1 326	1 413	1 356	1 456
FINANCING ACTIVITIES											
Proceeds from Long-Term Debt	2 773	3 400	3 600	2 000	1 800	800	400	0	0	0	800
Sinking Fund Withdrawals	146	0	0	182	303	767	173	50	330	131	224
Retirement of Long-Term Debt	(1 030)	(330)	(1 002)	(356)	(1 278)	(1 020)	(469)	(300)	(412)	(750)	(1 178)
Other	10	(10)	(10)	(11)	(11)	(11)	11	(5)	(5)	(5)	(5)
	1 898	3 059	2 588	1 815	814	535	115	(255)	(87)	(624)	(159)
INVESTING ACTIVITIES											
Property, Plant and Equipment, net of contributions	(2 673)	(3 600)	(3 063)	(2 395)	(1 788)	(1 398)	(929)	(748)	(757)	(785)	(810)
Sinking Fund Payment	(146)	(246)	(210)	(244)	(282)	(334)	(235)	(241)	(246)	(238)	(235)
Other	(70)	(53)	(58)	(47)	(131)	(95)	(87)	(85)	(84)	(81)	(80)
	(2 889)	(3 899)	(3 330)	(2 686)	(2 202)	(1 827)	(1 250)	(1 074)	(1 087)	(1 104)	(1 125)
Net Increase (Decrease) in Cash	(350)	(110)	103	66	(243)	74	149	(3)	239	(373)	173
Cash at Beginning of Year	956	606	496	599	665	422	497	646	643	883	510
Cash at End of Year	606	496	599	665	422	497	646	643	883	510	683

19.0 CAPITAL EXPENDITURE & DEMAND SIDE MANAGEMENT FORECAST (CEF16)

CAPITAL EXPENDITURE & DEMAND SIDE MANAGEMENT FORECAST (CEF16)

(in millions of dollars)

	Total Project Cost	2017 Outlook	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2018-2027 10 Year Total	20 Year Total
Major New Generation & Transmission														
Executing Projects														
Keeyask - Generation	8 726.0	914.2	1 077.5	1 290.5	1 116.7	867.9	707.1	329.9	58.2	2.4	1.5	0.9	5 452.6	6 366.8
Bipole III Reliability:														
Bipole III - Transmission Line	1 957.6	477.0	511.2	345.5	9.0	1.9	-	-	-	-	-	-	867.7	1 344.6
Bipole III - Converter Stations	2 780.7	821.5	679.0	286.3	8.0	0.6	-	-	-	-	-	-	973.9	1 795.4
Bipole III - Collector Lines	246.6	55.1	36.4	24.4	-	-	-	-	-	-	-	-	60.8	116.0
Bipole III - Community Development Initiative	56.6	2.6	2.7	0.9	-	-	-	-	-	-	-	-	3.6	6.2
Bipole III Total	5 041.5	1 356.2	1 229.3	657.1	17.1	2.5	-	-	-	-	-	-	1 906.0	3 262.2
Wuskwatim - Generation	1 421.6	4.1	5.4	-	-	-	-	-	-	-	-	-	5.4	9.5
Pointe du Bois Spillway Replacement	575.7	6.8	4.9	5.7	-	-	-	-	-	-	-	-	10.6	17.4
Manitoba-Minnesota Transmission Project	453.2	7.0	86.8	114.3	82.9	146.8	-	-	-	-	-	-	430.8	437.8
Conawapa - Generation	379.8	18.3	-	-	-	-	-	-	-	-	-	-	-	18.3
Kelsey Improvements & Upgrades	336.9	3.7	7.3	9.0	-	-	-	-	-	-	-	-	16.3	20.0
Riel 230/500kV Station	319.9	1.4	-	-	-	-	-	-	-	-	-	-	-	1.4
Gillam Redevelopment and Expansion Program (GREP)	266.5	15.1	36.9	39.7	37.2	31.5	28.3	28.0	16.9	2.1	2.1	3.8	226.5	241.5
Kettle Improvements & Upgrades	112.2	18.5	12.6	1.0	-	-	-	-	-	-	-	-	13.6	32.1
Pointe du Bois - Transmission	82.4	4.1	0.1	-	-	-	-	-	-	-	-	-	0.1	4.1
Manitoba-Saskatchewan Transmission Project	56.5	3.1	3.9	2.3	18.6	17.7	10.8	-	-	-	-	-	53.3	56.4
Grand Rapids Fish Hatchery Upgrade & Expansion	23.5	2.8	11.7	6.2	1.4	-	-	-	-	-	-	-	19.2	22.1
Subtotal Executing Projects		2 355.4	2 476.2	2 125.9	1 273.9	1 066.4	746.1	357.9	75.1	4.5	3.6	4.7	8 134.3	10 489.7
Long Term Planning Investments														
Single Cycle Gas Turbines & Thermal Transmission	NA	-	-	-	-	-	-	-	-	-	-	-	-	1.6
Subtotal Planning Items		-	-	-	-	-	-	-	-	-	-	-	-	1.6
MAJOR NEW GENERATION & TRANSMISSION TOTAL		**2 355.4**	**2 476.2**	**2 125.9**	**1 273.9**	**1 066.4**	**746.1**	**357.9**	**75.1**	**4.5**	**3.6**	**4.7**	**8 134.3**	**10 491.3**

CAPITAL EXPENDITURE & DEMAND SIDE MANAGEMENT FORECAST (CEF16)
(in millions of dollars)

	Total Project Cost	2017 Outlook	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2018-2027 10 Year Total	20 Year Total
Business Operations Capital														
Electric Segment														
Generation & Wholesale														
Executing Projects														
Pine Falls Units 1-4 Major Overhauls	88.8	19.1	20.3	9.9	-	-	-	-	-	-	-	-	30.1	49.2
Great Falls Unit 4 Overhaul	52.5	0.6	0.1	-	-	-	-	-	-	-	-	-	0.1	0.7
Water Licenses & Renewals	99.0	13.6	8.6	8.8	9.0	7.8	0.0	-	-	-	-	-	34.3	47.9
Projects between $2 Million & $50 Million	703.4	51.5	60.2	32.1	8.5	5.1	3.6	1.9	3.5	0.2	-	-	115.1	166.6
Subtotal Executing Projects		84.8	89.2	50.9	17.5	12.9	3.6	1.9	3.5	0.2	-	-	179.6	264.4
Potential Investments														
Brandon Units 6 & 7 "C" Overhaul Program	50.5	-	-	-	-	1.1	13.0	11.9	13.5	11.0	-	-	50.5	50.5
Investments between $2 Million & $50 Million	28.7	-	-	0.5	7.8	12.1	5.1	3.1	-	-	-	-	28.7	28.7
Subtotal Potential Investments		-	-	0.5	7.8	13.3	18.1	15.0	13.5	11.0	-	-	79.2	79.2
Programs	NA	20.4	20.8	21.2	21.7	22.1	22.5	26.4	23.5	23.9	24.4	24.9	231.4	507.4
Planning Investments														
Generator and Turbine Replacements and Refurbishment	NA	-	-	2.0	10.0	10.0	20.0	30.0	40.0	60.0	60.0	60.0	292.0	772.0
Governor & Excitation Replacements	NA	-	-	4.0	8.0	8.0	10.0	10.0	10.0	10.0	10.0	10.0	80.0	230.0
Transformer and Breaker Replacements	NA	-	-	4.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	76.0	157.0
Water Licenses & Renewals	NA	-	-	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	54.0	108.0
AC/DC Electrical Upgrades	NA	-	-	-	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	72.0	153.0
Infrastructure Upgrades/Replacements	NA	-	-	4.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	52.0	96.0
Powerhouse Upgrades/Refurbishment	NA	-	-	4.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	100.0	208.0
Water Control Refurbishment/Upgrades	NA	-	-	2.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	50.0	104.0
Subtotal Planning Investments		-	-	26.0	66.0	66.0	78.0	88.0	98.0	118.0	118.0	118.0	776.0	1 828.0
Portfolio Adjustments	NA	(2.2)	(15.0)	1.4	(3.0)	(4.2)	(7.6)	3.7	(3.5)	(10.3)	3.3	5.8	(29.3)	139.9
Generation & Wholesale Total		**103.0**	**95.0**	**100.0**	**110.0**	**110.0**	**114.6**	**135.0**	**135.0**	**142.9**	**145.7**	**148.7**	**1 236.9**	**2 819.0**

CAPITAL EXPENDITURE & DEMAND SIDE MANAGEMENT FORECAST (CEF16)

(in millions of dollars)

	Total Project Cost	2017 Outlook	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2018-2027 10 Year Total	20 Year Total
Business Operations Capital														
Electric Segment														
Transmission														
Executing Projects														
Rockwood East 230/115kV Station	50.0	0.2	-	-	-	-	-	-	-	-	-	-	-	0.2
Lake Winnipeg East System Improvements	75.5	30.5	18.6	-	-	-	-	-	-	-	-	-	18.6	49.2
Letellier - St. Vital 230kV Transmission	58.8	1.2	1.5	1.7	36.7	14.0	-	-	-	-	-	-	53.8	55.0
Transmission Line Upgrades for Improved Clearance	74.7	4.6	5.0	5.1	5.2	16.7	17.0	17.3	-	-	-	-	66.3	71.0
Steinbach Area 230-66kV Capacity Enhance	83.9	1.7	9.4	25.9	17.2	25.6	1.9	2.0	-	-	-	-	81.9	83.6
HVDC Dorsey Synchronous Condenser Refurbishment	73.6	7.5	6.9	0.5	0.0	0.0	0.0	0.0	5.3	2.8	0.5	-	16.1	23.6
HVDC Transformer Replacement Program	178.4	8.4	14.4	9.9	0.4	0.1	1.0	-	1.2	7.2	5.6	1.1	40.9	67.7
Projects between $2 Million & $50 Million	699.8	49.3	57.1	51.8	57.4	25.4	30.0	27.3	30.7	27.2	7.3	3.8	318.1	383.1
Subtotal Executing Projects		103.5	112.9	94.9	116.9	81.7	50.0	46.7	37.2	37.2	13.3	5.0	595.9	733.4
Potential Investments														
Bipole 2 Thyristor Valve Replacement	236.0	-	-	0.5	0.5	1.3	13.6	22.9	57.4	58.9	60.0	20.9	236.0	236.0
Transmission Transformers Sustainment Program	64.4	-	-	-	0.2	0.3	2.2	1.3	1.9	11.3	3.8	10.7	31.8	64.4
Investments between $2 Million & $50 Million	31.4	-	-	4.7	6.1	0.1	-	0.7	4.8	7.6	7.3	-	31.4	31.4
Subtotal Potential Investments		-	-	5.2	6.9	1.8	15.8	24.8	64.1	77.8	71.1	31.6	299.1	331.8
Programs	NA	39.2	39.2	39.2	40.0	40.8	41.6	42.5	43.3	44.2	45.1	46.0	422.0	918.7
Planning Investments														
Communication Upgrades & Replacements	NA	-	-	-	-	6.3	12.6	9.6	3.3	1.2	1.2	1.2	35.4	46.2
HVDC Upgrades & Replacements	NA	-	-	-	-	3.6	7.0	9.7	8.8	7.7	19.2	32.3	88.3	495.9
Pointe du Bois Transmission Phase 2	NA	-	-	-	-	2.3	9.0	13.5	18.0	2.3	6.0	-	51.1	51.1
Capacity Enhancements & Upgrades T/L	NA	-	-	-	-	-	-	-	-	-	2.0	-	2.0	102.0
Capacity Enhancements & Upgrades Stations	NA	-	-	-	-	19.3	26.7	25.6	-	-	7.7	16.7	96.0	161.9
Transmission Line Footing Sustainment Program	NA	-	-	-	-	2.5	2.5	2.5	2.5	2.5	7.5	7.5	27.5	50.0
Protection Relays Sustainment Program	NA	-	-	-	-	0.3	0.3	0.3	0.3	0.3	0.3	0.6	2.4	7.8
Subtotal Planning Investments		-	-	-	-	34.3	58.1	61.2	32.9	14.0	43.9	58.3	302.7	914.9
Portfolio Adjustments		(12.9)	(20.2)	(5.4)	(23.8)	(18.6)	(25.6)	(35.2)	(37.6)	(23.2)	(23.4)	18.3	(194.6)	240.1
Transmission Total		**129.9**	**132.0**	**134.0**	**140.0**	**140.0**	**140.0**	**140.0**	**140.0**	**150.0**	**150.0**	**159.2**	**1 425.2**	**3 138.9**

CAPITAL EXPENDITURE & DEMAND SIDE MANAGEMENT FORECAST (CEF16)

(in millions of dollars)

	Total Project Cost	2017 Outlook	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2018-2027 10 Year Total	20 Year Total
Business Operations Capital														
Electric Segment														
Marketing & Customer Service														
Executing Projects														
New Madison Station - 115/24kV Station	87.1	11.7	4.5	-	-	-	-	-	-	-	-	-	4.5	16.2
St. Vital Station 115/24kV Station	51.3	27.0	21.6	1.2	-	-	-	-	-	-	-	-	22.8	49.8
Dawson Road Station - 66/24kV	51.8	0.3	18.3	19.2	13.9	-	-	-	-	-	-	-	51.4	51.7
New Adelaide Station - 66/12kV	62.1	32.1	10.4	3.2	0.9	-	-	-	-	-	-	-	14.5	46.5
Projects between $2 Million & $50 Million	430.9	107.8	62.9	40.3	12.1	-	-	-	-	-	-	-	115.3	223.1
Subtotal Executing Projects		178.8	117.7	63.9	26.9	-	-	-	-	-	-	-	208.5	387.3
Programs	NA	139.2	156.0	176.3	179.8	183.4	186.2	189.9	193.7	197.6	201.5	205.6	1 870.1	4 054.7
Planning Investments														
Customer Connections – Distribution Lines	NA	-	-	-	-	-	1.8	2.7	3.4	3.6	4.4	4.0	19.9	70.0
Capacity Upgrades – Distribution Lines	NA	-	-	-	-	-	5.5	8.6	10.6	11.3	13.9	12.7	62.7	220.4
Capacity Upgrades – Distribution Stations	NA	-	-	-	-	-	7.4	11.6	14.2	15.2	18.6	17.1	84.0	295.4
System Renewal of Infrastructure – Distribution Lines	NA	-	-	-	-	-	3.7	5.8	7.1	7.5	9.2	8.5	41.7	146.6
System Renewal of Infrastructure – Distribution Stations	NA	-	-	-	-	-	12.2	19.1	23.5	25.0	30.7	28.2	138.7	487.8
Subtotal Planning Investments		-	-	-	-	-	30.5	47.9	58.8	62.6	76.7	70.5	347.0	1 220.3
Portfolio Adjustments		(45.6)	(30.6)	(5.0)	13.6	32.0	(26.0)	(19.8)	(30.1)	5.2	(16.6)	(8.8)	(86.0)	(235.6)
Marketing & Customer Service Total		**272.4**	**243.1**	**235.2**	**220.3**	**215.4**	**190.7**	**218.0**	**222.4**	**265.4**	**261.7**	**267.3**	**2 339.5**	**5 426.7**

CAPITAL EXPENDITURE & DEMAND SIDE MANAGEMENT FORECAST (CEF16)
(in millions of dollars)

	Total Project Cost	2017 Outlook	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2018-2027 10 Year Total	20 Year Total
Business Operations Capital														
Electric Segment														
Human Resources & Corporate Services														
Executing Projects														
Projects between $2 Million & $50 Million	94.0	26.7	5.1	1.7	-	-	-	-	-	-	-	-	6.8	33.6
Potential Investments														
Investments between $2 Million & $50 Million	13.9	-	-	-	13.0	-	-	-	-	-	-	-	13.0	13.0
Programs	NA	43.4	48.3	52.8	53.9	55.0	56.1	57.2	58.3	59.5	60.7	61.9	563.6	1 222.8
Portfolio Adjustments	NA	(2.0)	1.5	0.5	(11.9)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(9.6)	(11.2)
Human Resources & Corporate Services Total		**68.1**	**55.0**	**55.0**	**55.0**	**55.0**	**56.1**	**57.2**	**58.4**	**59.5**	**60.7**	**61.9**	**573.9**	**1 258.3**
		68.1	**55.0**	**55.0**	**55.0**	**55.0**	**56.1**	**57.2**	**58.4**	**59.5**	**60.7**	**61.9**	**573.9**	**1 258.3**
Finance & Strategy														
Programs	NA	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	2.2	4.7
Finance & Strategy Total		**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**2.2**	**4.7**
Unallocated Target Adjustment	NA	-	0.4	(7.6)	(9.5)	(9.4)	(2.3)	(29.7)	(12.2)	(2.6)	22.1	21.7	(28.9)	187.0
ELECTRIC BUSINESS OPERATIONS CAPITAL TOTAL		**573.6**	**525.8**	**516.8**	**516.0**	**511.2**	**499.4**	**520.7**	**543.7**	**615.5**	**640.5**	**659.0**	**5 548.7**	**12 834.5**

CAPITAL EXPENDITURE & DEMAND SIDE MANAGEMENT FORECAST (CEF16)

(in millions of dollars)

	Total Project Cost	2017 Outlook	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2018-2027 10 Year Total	20 Year Total
Business Operations Capital														
Natural Gas Segment														
Marketing & Customer Service														
Executing Projects														
Projects between $2 Million & $50 Million	41.7	25.3	2.7	0.3	-	-	-	-	-	-	-	-	3.0	28.3
Programs	NA	31.1	33.9	40.9	41.8	42.6	43.4	44.3	45.2	46.1	47.0	48.0	433.2	941.5
Portfolio Adjustments	NA	(5.6)	(5.6)	(8.8)	(12.5)	(11.5)	(10.7)	(9.1)	(11.7)	(7.0)	(8.1)	(8.4)	(93.4)	(157.4)
Marketing & Customer Service Total		**50.8**	**31.0**	**32.4**	**29.2**	**31.1**	**32.7**	**35.2**	**33.5**	**39.1**	**38.9**	**39.6**	**342.8**	**812.4**
NATURAL GAS BUSINESS OPERATIONS CAPITAL TOTAL		**50.8**	**31.0**	**32.4**	**29.2**	**31.1**	**32.7**	**35.2**	**33.5**	**39.1**	**38.9**	**39.6**	**342.8**	**812.4**
BUSINESS OPERATIONS CAPITAL TOTAL		**624.4**	**556.8**	**549.2**	**545.2**	**542.3**	**532.2**	**555.9**	**577.3**	**654.6**	**679.4**	**698.6**	**5 891.5**	**13 646.9**
CAPITAL EXPENDITURE FORECAST TOTAL		**2 979.8**	**3 033.0**	**2 675.1**	**1 819.1**	**1 608.7**	**1 278.3**	**913.8**	**652.3**	**659.1**	**683.0**	**703.3**	**14 025.8**	**24 138.2**
Year End Outlook Adjustment - Electric	NA	(45.0)	-	-	-	-	-	-	-	-	-	-	-	(45.0)
REVISED CAPITAL EXPENDITURE FORECAST TOTAL		**2 934.8**	**3 033.0**	**2 675.1**	**1 819.1**	**1 608.7**	**1 278.3**	**913.8**	**652.3**	**659.1**	**683.0**	**703.3**	**14 025.8**	**24 093.2**
ELECTRIC CAPITAL TOTAL		**2 883.9**	**3 002.0**	**2 642.7**	**1 789.9**	**1 577.6**	**1 245.6**	**878.6**	**618.8**	**620.0**	**644.0**	**663.7**	**13 683.0**	**23 280.8**
NATURAL GAS CAPITAL TOTAL		**50.8**	**31.0**	**32.4**	**29.2**	**31.1**	**32.7**	**35.2**	**33.5**	**39.1**	**38.9**	**39.6**	**342.8**	**812.4**
Demand Side Management Forecast														
Programs - Electric	NA	50.1	55.7	99.4	94.3	88.9	86.9	66.5	60.3	62.3	66.6	70.7	751.6	1 557.7
Programs - Natural Gas	NA	9.7	10.3	11.7	10.8	10.8	10.9	10.4	10.6	10.4	10.6	10.3	106.8	205.0
Demand Side Management Total		**59.9**	**66.0**	**111.1**	**105.1**	**99.6**	**97.8**	**77.0**	**70.8**	**72.8**	**77.2**	**81.1**	**858.4**	**1 762.6**
ELECTRIC CAPITAL & DEMAND SIDE MANAGEMENT TOTAL		**2 934.1**	**3 057.7**	**2 742.1**	**1 884.2**	**1 666.5**	**1 332.5**	**945.2**	**679.1**	**682.4**	**710.6**	**734.4**	**14 434.6**	**24 838.5**
NATURAL GAS CAPITAL & DEMAND SIDE MANAGEMENT TOTAL		**60.6**	**41.4**	**44.0**	**40.0**	**41.8**	**43.6**	**45.6**	**44.1**	**49.5**	**49.5**	**50.0**	**449.6**	**1 017.3**

20.0 ELECTRIC OPERATIONS FINANCIAL STATEMENTS (MH16)

ELECTRIC OPERATIONS (MH16)
PROJECTED OPERATING STATEMENT
(In Millions of Dollars)

For the year ended March 31

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
REVENUES											
Domestic Revenue											
at approved rates	1 517	1 569	1 561	1 552	1 551	1 552	1 559	1 567	1 577	1 584	1 593
additional*	-	88	255	397	551	717	766	817	870	923	979
BPIII Reserve Account	(96)	(119)	9	71	71	71	71	24	-	-	-
Extraprovincial	468	454	432	455	578	696	795	818	844	707	714
Other	27	30	31	31	33	33	34	34	35	35	36
	1 915	2 022	2 287	2 507	2 784	3 069	3 225	3 260	3 325	3 250	3 321
EXPENSES											
Operating and Administrative	535	518	501	511	513	524	536	548	559	571	583
Finance Expense	613	574	662	721	774	829	1 049	1 072	1 057	1 033	999
Finance Income	(18)	(16)	(20)	(27)	(27)	(32)	(38)	(17)	(21)	(22)	(17)
Depreciation and Amortization	384	396	471	515	554	597	689	714	725	739	751
Water Rentals and Assessments	131	124	112	113	114	117	127	128	131	131	131
Fuel and Power Purchased	130	135	166	146	162	149	140	138	141	128	129
Capital and Other Taxes	118	132	144	154	161	165	173	174	174	174	174
Other Expenses	60	115	109	481	94	92	71	64	67	71	76
Corporate Allocation	8	8	8	8	8	8	8	8	8	8	8
	1 962	1 987	2 153	2 623	2 354	2 449	2 755	2 828	2 841	2 832	2 833
Net Income before Net Movement in Reg. Deferral	(47)	35	134	(116)	430	620	470	432	484	418	488
Net Movement in Regulatory Deferral	69	68	106	462	69	61	40	(49)	(49)	(48)	(45)
Net Income	22	102	241	346	499	681	510	383	435	369	443
Net Income Attributable to:											
Manitoba Hydro	**34**	**111**	**242**	**344**	**494**	**673**	**500**	**372**	**432**	**367**	**440**
Non-controlling Interest	(12)	(9)	(1)	2	5	8	9	11	3	2	3
* Additional Domestic Revenue											
Percent Increase	0.00%	7.90%	7.90%	7.90%	7.90%	7.90%	2.00%	2.00%	2.00%	2.00%	2.00%
Cumulative Percent Increase	0.00%	7.90%	16.42%	25.62%	35.55%	46.25%	49.18%	52.16%	55.21%	58.31%	61.48%
Financial Ratios											
Equity	15%	15%	14%	15%	16%	18%	19%	20%	22%	23%	25%
EBITDA Interest Coverage	1.50	1.57	1.76	1.88	2.01	2.21	2.16	2.11	2.20	2.18	2.30
Capital Coverage	1.08	1.31	1.49	1.69	2.11	2.60	2.33	2.30	2.17	2.00	2.09

ELECTRIC OPERATIONS (MH16)
PROJECTED BALANCE SHEET
(In Millions of Dollars)

For the year ended March 31	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
ASSETS											
Plant in Service	13 256	13 881	19 254	19 876	20 938	26 363	30 693	31 222	31 858	32 522	33 133
Accumulated Depreciation	(985)	(1 319)	(1 749)	(2 197)	(2 634)	(3 143)	(3 724)	(4 347)	(4 961)	(5 625)	(6 231)
Net Plant in Service	12 272	12 562	17 505	17 679	18 304	23 219	26 969	26 876	26 897	26 897	26 902
Construction in Progress	6 943	9 308	6 596	7 378	7 870	3 693	224	312	276	272	269
Current and Other Assets	1 721	1 909	2 275	2 451	2 239	1 917	1 727	1 921	2 075	1 806	1 989
Goodwill and Intangible Assets	270	485	725	869	1 271	1 225	1 180	1 135	1 092	1 049	1 007
Total Assets before Regulatory Deferral	21 206	24 264	27 101	28 377	29 684	30 054	30 099	30 244	30 340	30 024	30 168
Regulatory Deferral Balance	459	526	633	1 094	1 163	1 225	1 265	1 216	1 167	1 118	1 074
	21 665	24 790	27 734	29 471	30 847	31 279	31 364	31 461	31 507	31 143	31 242
LIABILITIES AND EQUITY											
Long-Term Debt	15 578	17 920	21 157	21 782	22 554	22 881	22 905	22 474	21 786	20 525	21 167
Current and Other Liabilities	3 415	3 905	3 303	4 067	4 209	3 666	3 249	3 417	3 708	4 226	3 232
Provisions	19	19	19	18	17	16	16	15	14	14	14
Deferred Revenue	444	460	486	515	537	546	556	566	577	588	599
BPIII Reserve Account	196	316	307	236	165	94	24	(0)	(0)	(0)	(0)
Retained Earnings	2 730	2 841	3 083	3 427	3 921	4 594	5 094	5 466	5 898	6 265	6 705
Accumulated Other Comprehensive Income	(761)	(714)	(665)	(616)	(600)	(562)	(522)	(521)	(520)	(520)	(520)
Total Liabilities and Equity before Regulatory Deferral	21 621	24 747	27 691	29 428	30 804	31 236	31 321	31 417	31 463	31 099	31 198
Regulatory Deferral Balance	44	44	44	44	44	44	44	44	44	44	44
	21 665	24 790	27 734	29 471	30 847	31 279	31 364	31 461	31 507	31 143	31 242
Net Debt	15 349	18 248	20 527	22 028	22 835	22 967	22 670	22 206	21 663	21 200	20 664
Total Equity	2 778	3 104	3 465	3 862	4 363	5 048	5 237	5 608	6 054	6 434	6 888
Equity Ratio	15%	15%	14%	15%	16%	18.02%	19%	20%	22%	23%	25%

ELECTRIC OPERATIONS (MH16)
PROJECTED CASH FLOW STATEMENT
(In Millions of Dollars)

For the year ended March 31	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
OPERATING ACTIVITIES											
Cash Receipts from Customers	2 007	2 131	2 268	2 425	2 701	2 986	3 141	3 224	3 313	3 237	3 308
Cash Paid to Suppliers and Employees	(876)	(917)	(881)	(880)	(903)	(908)	(923)	(937)	(954)	(952)	(964)
Interest Paid	(569)	(529)	(628)	(695)	(737)	(797)	(1 013)	(1 042)	(1 035)	(1 017)	(974)
Interest Received	7	5	12	21	17	17	9	8	14	14	10
	569	689	770	871	1 077	1 298	1 214	1 253	1 338	1 282	1 379
FINANCING ACTIVITIES											
Proceeds from Long-Term Debt	2 743	3 370	3 590	1 970	1 790	790	360	(10)	(10)	(50)	790
Sinking Fund Withdrawals	146	0	0	182	303	767	173	50	330	131	224
Retirement of Long-Term Debt	(1 030)	(330)	(1 002)	(336)	(1 278)	(1 020)	(449)	(290)	(412)	(715)	(1 178)
Other	10	(10)	(10)	(11)	(11)	(11)	11	(5)	(5)	(5)	(5)
	1 868	3 029	2 578	1 805	804	525	95	(255)	(97)	(639)	(169)
INVESTING ACTIVITIES											
Property, Plant and Equipment, net of contributions	(2 609)	(3 553)	(3 015)	(2 351)	(1 742)	(1 352)	(880)	(700)	(704)	(732)	(756)
Sinking Fund Payment	(146)	(246)	(210)	(244)	(282)	(334)	(235)	(241)	(246)	(238)	(235)
Other	(68)	(51)	(55)	(44)	(128)	(91)	(84)	(83)	(83)	(80)	(79)
	(2 822)	(3 850)	(3 280)	(2 639)	(2 152)	(1 777)	(1 199)	(1 024)	(1 033)	(1 050)	(1 070)
Net Increase (Decrease) in Cash	(384)	(131)	68	37	(272)	46	111	(26)	208	(408)	140
Cash at Beginning of Year	944	559	428	496	534	262	308	419	393	601	193
Cash at End of Year	559	428	496	534	262	308	419	393	601	193	333

21.0 GAS OPERATIONS FINANCIAL STATEMENTS (CGM16)

GAS OPERATIONS (CGM16)
PROJECTED OPERATING STATEMENT
(In Millions of Dollars)

For the year ended March 31	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
REVENUES											
Domestic Revenue	346	363	387	380	380	381	380	380	379	378	378
Furnace Replacement Program	(4)	(4)	(4)	0	0	0	0	0	0	0	0
at approved rates	342	360	383	380	380	381	380	380	379	378	378
additional revenue requirement*	0	0	0	0	3	4	8	13	17	18	23
	342	360	383	380	384	385	389	393	396	396	401
Cost of Gas Sold	192	228	228	228	228	228	227	226	226	225	224
Gross Margin	150	131	155	152	155	157	161	166	171	171	177
Other	2	2	2	2	2	2	2	2	2	2	2
	152	133	157	153	157	158	163	168	172	173	179
EXPENSES											
Operating and Administrative	68	67	60	61	62	63	64	65	66	68	69
Finance Expense	19	20	21	22	23	24	25	26	26	27	28
Depreciation and Amortization	22	23	24	25	26	27	28	29	30	31	33
Capital and Other Taxes	16	16	17	17	18	18	18	19	19	19	20
Other Expenses	11	16	13	13	14	12	12	12	12	12	12
Corporate Allocation	12	12	12	12	12	12	12	12	12	12	12
	147	154	147	151	154	155	158	162	165	169	173
Net Income before Net Movement in Reg. Deferral	4	(21)	9	3	3	3	5	6	7	4	6
Net Movement in Regulatory Deferral	(5)	20	(6)	1	0	(1)	(2)	(3)	(4)	(3)	(3)
Net Income	(0)	(1)	3	4	4	2	3	3	3	2	3
* Additional Revenue Requirement											
Percent Increase	0.00%	-1.00%	0.00%	0.00%	1.00%	0.00%	1.50%	1.25%	1.00%	0.00%	1.75%
Cumulative Percent Increase	0.00%	-1.00%	-1.00%	-1.00%	-0.01%	-0.01%	1.49%	2.76%	3.79%	3.79%	5.60%

GAS OPERATIONS (CGM16)
PROJECTED BALANCE SHEET
(In Millions of Dollars)

For the year ended March 31	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
ASSETS											
Plant in Service	559	592	626	656	688	721	757	791	830	869	908
Accumulated Depreciation	(40)	(56)	(72)	(89)	(107)	(125)	(144)	(164)	(185)	(207)	(229)
Net Plant in Service	518	536	554	567	581	596	612	626	645	662	679
Construction in Progress	5	4	4	4	4	4	4	4	4	4	4
Current and Other Assets	76	76	76	76	76	76	76	76	76	76	76
Goodwill and Intangible Assets	8	8	7	7	6	6	6	6	6	6	6
Total Assets before Regulatory Deferral	608	624	641	653	667	682	699	713	731	748	765
Regulatory Deferral Balance	100	112	106	106	106	104	101	97	93	91	88
	708	737	747	759	773	786	800	810	824	839	853
LIABILITIES AND EQUITY											
Long-Term Debt	370	400	390	420	430	420	450	460	435	485	495
Current and Other Liabilities	91	97	113	92	92	112	91	89	124	87	87
Provisions	-	-	-	-	-	-	-	-	-	-	-
Deferred Revenue	44	45	47	48	48	50	52	53	53	54	54
Share Capital	121	121	121	121	121	121	121	121	121	121	121
Retained Earnings	64	64	67	70	74	76	79	82	85	87	90
Total Liabilities and Equity before Regulatory Deferral	691	727	738	751	766	779	794	804	819	834	848
Regulatory Deferral Balance	17	9	9	8	7	7	6	5	5	5	5
	708	737	747	759	773	786	800	810	824	839	853
PUB Approved Equity Ratio	32%	31%	30%	30%	30%	30%	29%	29%	29%	29%	29%

GAS OPERATIONS (CGM16)
PROJECTED CASH FLOW STATEMENT
(In Millions of Dollars)

For the year ended March 31	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
OPERATING ACTIVITIES											
Cash Receipts from Customers	374	394	418	411	415	416	420	425	428	428	434
Cash Paid to Suppliers and Employees	(310)	(361)	(352)	(353)	(355)	(356)	(357)	(358)	(359)	(360)	(362)
Interest Paid	(19)	(20)	(21)	(22)	(22)	(23)	(24)	(25)	(26)	(26)	(28)
	46	14	45	36	38	37	39	41	43	42	45
FINANCING ACTIVITIES											
Proceeds from Long-Term Debt	30	30	10	30	10	10	40	10	10	50	10
Retirement of Long-Term Debt	0	0	0	(20)	0	0	(20)	(10)	0	(35)	0
Other	0	0	0	0	0	0	0	0	0	0	0
	30	30	10	10	10	10	20	-	10	15	10
INVESTING ACTIVITIES											
Property, Plant and Equipment, net of contributions	(63)	(46)	(47)	(44)	(46)	(47)	(49)	(47)	(53)	(53)	(53)
Other	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(2)	(1)	(1)	(1)
	(65)	(48)	(50)	(47)	(49)	(50)	(52)	(50)	(54)	(54)	(54)
Net Increase (Decrease) in Cash	10	(5)	5	(1)	(2)	(3)	8	(8)	(0)	3	0
Cash at Beginning of Year	(40)	(30)	(34)	(29)	(30)	(32)	(35)	(27)	(36)	(36)	(33)
Cash at End of Year	(30)	(34)	(29)	(30)	(32)	(35)	(27)	(36)	(36)	(33)	(33)

22.0 CORPORATE SUBSIDIARIES FINANCIAL STATEMENTS (CS16)

CORPORATE SUBSIDIARIES (CS16)
PROJECTED OPERATING STATEMENT
(In Millions of Dollars)

For the year ended March 31	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
REVENUES											
Revenue	62	69	74	76	77	79	80	82	83	84	86
Cost of Operations	37	41	44	45	46	47	48	49	49	50	51
	26	28	30	31	31	32	32	33	33	34	35
EXPENSES											
Operating and Administrative	16	18	18	18	19	19	20	20	20	21	21
Finance Expense	0	0	0	-	-	-	-	-	-	-	-
Finance Income	(0)	(0)	(0)	-	-	-	-	-	-	-	-
Depreciation and Amortization	2	2	2	2	2	2	2	0	0	0	0
Capital and Other Taxes	1	1	1	1	1	1	1	1	1	1	1
	19	20	21	21	21	22	22	21	21	22	22
Net Income before Net Movement in Reg. Deferral	7	8	9	10	10	10	10	12	12	13	13
Net Movement in Regulatory Deferral	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Net Income	7	8	9	10	10	10	10	12	12	12	13

CORPORATE SUBSIDIARIES (CS16)
PROJECTED BALANCE SHEET
(In Millions of Dollars)

For the year ended March 31	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
ASSETS											
Plant in Service	19	19	19	19	19	19	19	19	19	19	19
Accumulated Depreciation	(7)	(8)	(10)	(12)	(13)	(15)	(17)	(17)	(17)	(17)	(17)
Net Plant in Service	12	11	9	8	6	4	3	3	3	2	2
Construction in Progress	-	-	-	-	-	-	-	-	-	-	-
Current and Other Assets	61	68	79	91	102	114	126	139	151	164	176
Goodwill and Intangible Assets	0	1	1	1	0	0	0	-	-	-	-
Total Assets before Regulatory Deferral	73	80	89	99	109	119	129	141	154	166	179
Regulatory Deferral Balance	0	0	0	0	0	0	0	0	0	0	0
	73	80	89	99	109	119	129	141	154	166	179
LIABILITIES AND EQUITY											
Long-Term Debt	-	-	-	-	-	-	-	-	-	-	-
Current and Other Liabilities	7	6	6	6	6	6	6	6	6	6	6
Deferred Revenue	0	0	0	0	0	0	0	0	0	0	0
Share Capital	1	1	1	1	1	1	1	1	1	1	1
Retained Earnings	65	73	82	92	102	112	122	134	146	159	172
	73	80	89	99	109	119	129	141	154	166	179

CORPORATE SUBSIDIARIES (CS16)
PROJECTED CASH FLOW STATEMENT
(In Millions of Dollars)

For the year ended March 31	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
OPERATING ACTIVITIES											
Cash Receipts from Customers	61	68	74	76	77	79	80	82	83	84	86
Cash Paid to Suppliers and Employees	(54)	(59)	(63)	(64)	(66)	(67)	(68)	(69)	(71)	(72)	(73)
Interest Paid	(0)	(0)	(0)	-	-	-	-	-	-	-	-
Interest Received	0	0	0	-	-	-	-	-	-	-	-
	7	9	11	12	12	12	12	12	12	13	13
FINANCING ACTIVITIES											
Proceeds from Long-Term Debt	-	-	-	-	-	-	-	-	-	-	-
Retirement of Long-Term Debt	-	-	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-
INVESTING ACTIVITIES											
Property, Plant and Equipment, net of contributions	(2)	(1)	(0)	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-	-	-
	(2)	(1)	(0)	-	-	-	-	-	-	-	-
Net Increase (Decrease) in Cash	5	8	11	12	12	12	12	12	12	13	13
Cash at Beginning of Year	25	30	38	49	60	72	84	96	108	121	133
Cash at End of Year	30	38	49	60	72	84	96	108	121	133	146