MPA Morrison Park Advisors

Commercial Evaluation of Manitoba Hydro Preferred Development Plan Business Case

Prepared by Morrison Park Advisors
For

Manitoba Public Utilities Board

January 2014

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Executive Summary

Scope of Work

MPA was retained by the PUB to provide a commercial evaluation of the Manitoba Hydro Preferred Development Plan Business Case, as detailed in the NFAT. Specifically, MPA's review is to include

a) Consideration of the overall costs, risks and benefits being assumed by Manitoba Hydro in the pursuit of the Preferred Development Plan, particularly in light of potential alternatives to the Preferred Development Plan which could satisfy provincial and ratepayer objectives (commercial reasonableness of the Preferred Development Plan);

b) Consideration of the costs assumed, risks taken, and compensating benefits expected for each relevant stakeholder of Manitoba Hydro, including ratepayers, the Government of Manitoba, Manitoba taxpayers, and others (relative commercial reasonableness of the Preferred Development Plan for various stakeholders);

c) Consideration of commercial risks being assumed by Manitoba Hydro as part of its export agreements, and specifically how these risks relate to the risks being taken by Manitoba ratepayers in the event that export agreements do not perform according to optimal scenarios (commercial reasonableness of the export aspects of the Preferred Development Plan in relation to the domestic services portions); and

d) Consideration of specific financial impacts and risks being assumed as part of the Preferred Development Plan by the Government of Manitoba and the taxpayers of Manitoba, as they relate to the Province's credit rating, borrowing capacity, potential impact on other budgetary priorities, credit availability, and credit rates in the future.

Summary of Financial Model

MPA has constructed a financial model on Manitoba Hydro's electrical operations in order to address the scope of work put to MPA by the PUB under the NFAT. MPA relied upon the NFAT Business Case, the appendices thereto, and numerous discussions and correspondence with Manitoba Hydro management and employees on the matter of Manitoba Hydro operations, and economic and financial conditions. MPA received SPLASH (Simulation Program for Long-term Analysis of System Hydraulics) output from Manitoba Hydro with respect to the development plans considered under the NFAT.

MPA matched the SPLASH data with the development plans detailed in Appendix 11.4 of the NFAT Business Case, eliminating plans for which pro forma financial statement data was not provided. MPA extracted chained, opportunity export revenue for every given hydrological regime and model year, allowing for the determination of actual, annual opportunity export revenue, calculated for a given supply mix that Manitoba Hydro anticipates to eventuate in a given year. This information and extraction (from SPLASH), and application (to Appendix 11.4) allowed MPA to produce a set of financial

statements (income statement, balance sheet and cash flow statement) for every development plan modelled under Appendix 11.4 under all scenarios, and under all previous hydrology regimes.

In reaching our conclusions contained in this report, MPA has run the All Gas and Preferred Development plans, and Plans 4, 6 and 12 under the 2012 reference Manitoba load for all 99 years of hydrological history through year 2062 (at reference economics, energy and capital, for 495 total runs).

The All Gas and Preferred Development Plans were further run at high and low 2012 Manitoba load for all 99 years of hydrological history through year 2062 (at reference economics, energy and capital, for 396 total runs).

The Preferred Development Plan was further run at 4x 2013 DSM and 1x 2012 DSM (both at 2013 reference Manitoba load) for all 99 years of hydrological history through year 2062 (at reference economics, energy and capital, for 198 total runs).

The All Gas and Preferred Development plans, and Plans 4,6 and 12, were run for 21 different years of hydrological history, for every combination of reference, high and low economics, energy and capital costs, for a total of 546 runs per development plan, or 2730 total runs.

In total, MPA performed 3,819 different runs of the financial model. The financial model, as constructed in the manner detailed above, formed the basis for our financial conclusions reached in this report.

Findings on Ratepayer Total Costs

- Findings are in reference to the average probability weighted present value basis of domestic revenue
- Resource Plans 4 and 6, which include Keeyask, some level of transmission interconnection and natural gas plants, appear to fare consistently better than the other options
- Plans 14 and 12, which include Conawapa, are consistently ranked as more costly to ratepayers than Plans 4 and 6, which include Keeyask but not Conawapa
- Plan 1, the All Gas Plan, ranks poorly when economic variables such as inflation and interest rates are low, but better when they are moderate or high; this is particularly true with respect to the Preferred Plan 14, which is superior to All Gas in the low economics environment but not otherwise
- Plan 1, the All Gas Plan, ranks relatively poorly when the discount rate is lower at 6%, but better when the discount rate is higher at 10%, suggesting that the relative time value of money is an important consideration
- Plan 4, with a 250 MW interconnection, always ranks better than Plan 6, with a 750 MW interconnection

- Similarly, Plan 14 is better than Plan 12 in every case but one, suggesting that an earlier construction and export orientation for the Conawapa facility is better than a later one

- Changing Manitoba demand does not actually affect the total cost to ratepayers over 48 years very much, if all other variables are kept constant; the difference in total cost to ratepayers between High and Low Manitoba demand futures is not more than about 2% in any of the cases

Findings on Government Revenues

As might be expected, the differences between Resource Plans with respect to revenues for the Government of Manitoba are clear, and align with the construction of hydroelectric facilities.

Average Probability Weighted PV of Revenue to the Province of Manitoba
High, Ref and Low Economics, Energy and Capital
(2015-2062)
($ in millions)

	Development Plan				
Revenue	**1**	**4**	**6**	**12**	**14**
NPV @ 6.00%					
Water Rentals	$1,702	$1,883	$1,879	$2,034	$2,091
Provincial Debt Guarantee	$2,614	$3,031	$3,075	$3,561	$3,783
Capital Taxes	$1,584	$1,874	$1,883	$2,229	$2,275

In the Preferred Development Plan (14), Conawapa is built and built soonest, and hence water rental fees are greater, more debt must be guaranteed, and capital taxes are highest.

The differences between Plans (14) and (12), where Conawapa is built a few years later, are very modest. Similarly, the differences between Plans (4) and (6), which both include Keeyask but not Conawapa, are very minor, but these totals are noticeably lower than the Conawapa-based Resource Plans.

Findings on Export Orientation

As might be expected, the Preferred Development Plan (14), which includes the building of Conawapa earlier in time with the intention of signing long-term export contracts, includes the highest export revenues as a percentage of total Manitoba Hydro revenues**.**

Average Export Revenue as a Percentage of Total Revenue
All Gas and Preferred Development Plan
Reference Economics and Capital
(2015 - 2062)

	Development Plan	
Energy Scenario	**1**	**14**
Reference	9.5%	20.9%
High	11.9%	26.2%
Low	6.4%	14.3%

- Resource Plans which have a higher reliance on export revenues are more sensitive to changes in export prices; this is borne out by reference to the model results if all variables except energy prices are kept constant: for example, average present value costs to ratepayers in Preferred Plan (14) are 10% lower if export prices are higher; whereas in All Gas Plan (1) there is little difference between the total ratepayer costs between scenarios with High and Low export prices

- For government, higher exports mean that more of its revenue from Manitoba Hydro is actually coming from export jurisdictions, rather than ratepayers, which means that, *other things being equal*, the province as a whole should be receiving a net benefit

Findings on Hydrology

- Hydrology is critical to short-term issues, such as the potential for financial distress, but is less relevant to longer term issues such as the present value of ratepayer costs over a 48-year period or longer

- Though hydrology is less critical over longer terms, it does not mean that it is not relevant: even over a 35-year period the standard deviation of water flow is almost 5% of the historical average

- Resource plans heavy in hydroelectric investment, such as the Preferred Development Plan (14), are more sensitive to hydrology, and will therefore demonstrate greater variation in all financial results (including Manitoba ratepayer costs), especially in the short term but also over the longer term, other things being equal

Findings on Financial Distress

- Despite the fact that the most severe situations of financial distress caused by drought overwhelm distinctions between Resource Plans, there are useful distinctions that can be made

- These include sensitivity to hydrology, sensitivity to the timing of distress, and overall financial strength

- Some Resource Plans are more sensitive to hydrology than others

- It is inescapable that the net income of Manitoba Hydro will be more sensitive to hydrology if Keeyask, Conawapa or both are built

- It should be noted that this sensitivity goes both ways: these Resource Plans will be exposed to higher highs and lower lows in net income and other financial indicators based on the future course of hydrology

- Timing is extremely relevant, and there are distinctions between the resource plans

Conclusions

Analysis of the available data and construction of a financial model capable of incorporating hydrology has allowed for the illumination of a number of patterns, and a variety of observations that will, it is hoped, assist the PUB in making its recommendations to government on the NFAT Review of the Manitoba Hydro Preferred Development Plan.

Key observations have included:

- The ability of Manitoba Hydro to meet its financial targets over the next ten years without increasing rates beyond two times the rate of inflation – under all Resource Plans – is entirely dependent on the continued absence of a significant drought

- Different Resource Plans extend that period of fragility, including the Preferred Development Plan, which should not be expected to enter a time of more financial capacity for 20 years, unless rates are allowed to rise at more than double the rate of inflation for an extended period of time

- In the face of a sustained, severe drought, the choice of Resource Plan is irrelevant to the occurrence of distress, as the financial consequences of such a drought would overwhelm the differences between Resource Plans

- Choice of Resource Plan does affect the occurrence of financial distress due to drought in milder drought cases, and it also affects the magnitude of the problem that would be faced by government in the event of a drought of any kind

- The total, probability-adjusted present value of ratepayer costs over 48 years across all five Resource Plans is likely too narrowly distributed to allow for definitive selection of the “lowest cost” choice. These outcomes are essentially within the margin of error of the many calculations, estimates and assumptions that were required to construct the model

- The consistent patterns of sensitivity of specific Resource Plans to certain variables indicates that model analysis can provide a guide to identifying the concerns that should be part of any decision-making process

- An extremely important inter-generational decision is embedded in the choice of Resource Plan, as costs to Ratepayers will be distributed very differently over time.

Bearing these and other observations in mind, we would suggest the following recommendations:

a) Plans 4 and 6, which were largely indistinguishable from each other, resulted in costs to ratepayers that appear to be lower than other Resource Plans in many scenarios, if only marginally; this suggests that proceeding with Keeyask may be a prudent step to take at this time, but a more thorough review of the proposal to build Conawapa as part of the Preferred Development Plan should be undertaken closer to its final commitment date

b) Given the expected fragility of Manitoba Hydro during the first ten years of any Resource Plan, and beyond that in others, the Government of Manitoba may wish to calculate and reserve some of the funds it generates (e.g., through permits, approvals, income taxes, etc., related to the construction projects) to act as an initial financial buffer for the government in the event of drought and the need for financial assistance to Manitoba Hydro

c) Given the inevitability of a drought at some point in the future, and the expected financial impact that such a drought would have on Manitoba Hydro, particularly in the near term, consideration should be given to the development of an explicit policy on the future course of customer rates in such a situation; this policy could then be shared with credit rating agencies and others to address the potential concern that they may have that in the event of a drought some fraction of Manitoba Hydro debt might be financially unsupported.

1. Introduction

Morrison Park Advisors was retained by the Manitoba Public Utilities Board (hereinafter the "PUB") to assist in the consideration of various commercial aspects of the "Needs For and Alternatives To" (hereinafter the "NFAT") Review of Manitoba Hydro's Preferred Development Plan (hereinafter the "Preferred Development Plan").

1.1. Morrison Park Advisors

Morrison Park Advisors is an independent, partner-owned, Canadian investment bank providing financial advisory services to corporations and governments. MPA focuses on several industry sectors, including the regulated utility/energy infrastructure sector, in which it has substantial background and expertise. We provide independent expert advice to clients involved in regulatory processes; commercial litigation and arbitration; commercial and balance sheet restructuring events; debt and/or equity capital raising; and mergers, acquisitions and divestitures. Our ability to deliver top-tier financial advisory services is based on decades of combined experience and expertise developed at some of Canada's leading investment banks, while serving many of Canada's largest and most sophisticated corporate clients as well as federal, provincial and municipal governments and quasi-government entities.

Information on the MPA partners who participated in the preparation of this Report is available in Appendix A.

For more information on MPA, please visit our website at www.morrisonpark.com.

1.1.1. Independence of MPA

MPA confirms that:

a) neither MPA nor any of its affiliated entities is an associated entity or affiliated entity or insider of Manitoba Hydro or any of its affiliates;

b) prior to the date hereof, MPA has not been engaged as financial advisor to Manitoba Hydro or any of its affiliates; and

c) during the term of its engagement, MPA will not be engaged by Manitoba Hydro or its affiliates as a financial advisor in respect of the NFAT.

1.2. MPA's Mandate and Scope of Work

MPA was retained by the PUB to provide a commercial evaluation of the Manitoba Hydro Preferred Development Plan Business Case, as detailed in the NFAT. Specifically, MPA's review is to include:

e) Consideration of the overall costs, risks and benefits being assumed by Manitoba Hydro in the pursuit of the Preferred Development Plan, particularly in light of potential alternatives to the Preferred Development Plan which could satisfy provincial and ratepayer objectives (commercial reasonableness of the Preferred Development Plan);

f) Consideration of the costs assumed, risks taken, and compensating benefits expected for each relevant stakeholder of Manitoba Hydro, including ratepayers, the Government of Manitoba, Manitoba taxpayers, and others (relative commercial reasonableness of the Preferred Development Plan for various stakeholders);

g) Consideration of commercial risks being assumed by Manitoba Hydro as part of its export agreements, and specifically how these risks relate to the risks being taken by Manitoba ratepayers in the event that export agreements do not perform according to optimal scenarios (commercial reasonableness of the export aspects of the Preferred Development Plan in relation to the domestic services portions); and

h) Consideration of specific financial impacts and risks being assumed as part of the Preferred Development Plan by the Government of Manitoba and the taxpayers of Manitoba, as they relate to the Province's credit rating, borrowing capacity, potential impact on other budgetary priorities, credit availability, and credit rates in the future.

1.3. Report Structure

The Business Case and supporting evidence presented by Manitoba Hydro in favour of the Preferred Development Plan is extremely detailed (the initial filing ran to approximately 5,000 pages, and responses to Information Requests have been similarly voluminous). We have attempted to condense many concepts in a relatively brief narrative in order to highlight critical issues that we believe should be considered by the PUB. In addition to the sections of this Report described below, we have provided Appendices which provide greater detail on certain matters which, while important, would distract from the narrative and its core issues.

Table 1. Report Structure

Section	Title	Matters Addressed
2	Context	• Manitoba Electricity System • Stakeholders and Their Interests • Risks Relevant to Electricity Resource Planning
3	Resource Alternatives	• Features of Plans • Variables that Should be Considered
4	Financial Modeling	• Approach Taken • Findings
5	Specific Issues	• Weighted Average Cost of Capital and Discount Rate • Exports • Potential Impact on Province of Manitoba
6	Costs, Risks and Benefits	• Ratepayers • Government of Manitoba • Relative Distribution Issues
7	Recommendations and Conclusions	• Report recommendations and conclusions

1.4. Note on the Use of Projections and Models

In preparing our Report, we have made use of the following:

a) Information that was made available by Manitoba Hydro through this regulatory process, inclusive of the NFAT Business Case and supporting evidence admitted, responses to all information requests, and direct discussions that were organized by the PUB for Independent Expert Consultants;

b) Information that was publicly available, whether from Manitoba Hydro, the Government of Manitoba, from public authorities such as electricity system and market operators in other jurisdictions, or from general corporate, economic and financial sources;

c) Financial information available through paid subscription services;

d) Information, advice and opinions of other Independent Expert Consultants participating in this regulatory process on behalf of the PUB, in the form of discussions, meetings and reports;

e) Our general experience, qualifications and skills in financial analysis and the preparation of valuations and opinions on fairness from a financial point of view.

A very significant component of the work of this Report involved the use of forecasts, projections and estimates, and in particular those provided by Manitoba Hydro in evidence and in response to information requests. We have not passed any judgment on the validity or reliability of these projections and estimates (except in select cases specifically addressed below), but rather have assumed

that they were prepared with all due care based on the professional qualifications of those responsible for them.

It is critical to point out, however, the fundamental uncertainty that underlies many of the projections in question, particularly as they extend out not only years, but decades. Useful forecasts for the near to medium term are typically based on the belief – sometimes proven by subsequent events to be erroneous – that the future will consist of incremental changes to the practices of the past. However, the longer the time horizon of the forecast, the more likely that changes will cease to be incremental, and become truly unpredictable. What may appear to be reasonable today may at some point in the future – with the benefit of hindsight – look like a terrible mistake, or a massive stroke of luck. Prices change, technology changes, market dynamics change, the relative cost of goods changes: all in unpredictable ways over time.

Technological advances, in particular, can render assumptions obsolete even in relatively short periods of time. The development of hydraulic fracturing in the natural gas industry over the past decade is only a recent example of expectations about future market conditions being totally undermined: widespread expectations a decade ago were that North America would by now be supply constrained and increasingly reliant on expensive imports of natural gas from elsewhere, yet now there is a rush to find ways to export an overabundant commodity that has dropped dramatically in price. In earlier decades similar received wisdom was overturned (for example, there was a time in the mid-twentieth century when many experts believed that nuclear power would render electricity "too cheap to meter".[1] Needless to say, the aspiration was never achieved).

There is a significant danger in assuming that a view of the future from the perspective of today will be very accurate. All such assumptions should be approached with humility, and treated with respect as the best available basis for decision-making, but without claiming them to be more than what they are. Decisions cannot be made without taking a view of the future, but the future may prove unwilling to agree with the forecasts made of it.

It is commonplace that commercial transactions are analyzed using mathematical models, often providing a degree of precision measured in decimal points, which sometimes gives the illusion of accuracy or predictive power. We have used such models in the preparation of this Report. However, these models are only as accurate as the assumptions about the future that underlie them. Since those assumptions must be given a broad range because of the difficulty inherent in predicting the future, especially over decades, the models should and do result in outputs with an equally broad range. This means that mathematical models sometimes may be capable of excluding certain decision options from the realm of reasonable commercial choice, but cannot always point to a single preferred outcome among several. In these cases, decisions still must be made, but they must be rendered on the basis of judgement.

Commercial decisions are ultimately about judgement, and judgement is extremely difficult to quantify.

[1] The phrase was coined by Lewis L. Strauss, Chairman of the United States Atomic Energy Commission in a 1954 Speech to the National Association of Science Writers.

2. Context

The Preferred Development Plan is a long-term resource plan for electricity in the Province of Manitoba. Analyzing its features requires an understanding of the electricity system in the Province, and its expected needs.

2.1. Manitoba Hydro

Manitoba Hydro is the sole utility provider of electricity in the province, and is a Crown Corporation with the mandate[2] to:

- Provide electricity to Manitoba ratepayers as economically as possible, consistent with a safe and reliable system; and
- Exploit opportunities to export electricity and electricity-related services to the benefit of the Province of Manitoba and its ratepayers.

As a Crown Corporation, Manitoba Hydro does not pay dividends to the province of Manitoba (the "shareholder"),[3] nor does it pay income tax. Notwithstanding the organization of the entity on corporate lines – with debt and "equity" on its balance sheet – it is not a profit-maximizing enterprise. By legislation, it is entitled only to seek revenues sufficient to satisfy its operating costs, debt servicing needs, and to maintain reserves for various purposes, including the management of contingencies and smoothing of rates over time.[4] The corporation's "equity" is better understood as a form of reserve fund, and its "profits" in any given year as a contribution to that reserve.

[2] The *Manitoba Hydro Act* describes the objects and purposes as follows:

> 2. The purposes and objects of this *Act* are to provide for the continuance of a supply of power adequate for the needs of the province, and to engage in and to promote economy and efficiency in the development, generation, transmission, distribution, supply and end-use of power and, in addition, are
> (a) to provide and market products, services and expertise related to the development, generation, transmission, distribution, supply and end-use of power, within and outside the province; and
> (b) to market and supply power to persons outside the province on terms and conditions acceptable to the board.

The *Terms of Reference* of the Manitoba Hydro Electric Board specify the following:

> The corporation is charged with responsibilities which include, to ensure a safe, reliable, economical and environmentally responsible supply of energy for Manitoba, and to earn revenues to keep rates low for Manitobans through the export of power and the provision of energy-related services.

[3] Note that in fiscal year 2002-3, the Government of Manitoba received a special dividend payment of $203 million. This payment was specifically required by amendment of the *Manitoba Hydro Act*. See Statutes of Manitoba, c. 41.

[4] Please see *Manitoba Hydro Act*, s. 39(1) and s. 40(1).

By agreement with the shareholder, the target level of "equity" in the corporation is 25% of total capital,[5] as defined by the following formula:

Formula 1. Equity Ratio Calculation

$$\frac{\text{Total Equity} = \{\text{Retained Earnings} + \text{Contributions in aid of Construction} + \text{Accumulated Other Comprehensive Income} + \text{Non-controlling Interest}\}}{\text{(Long-term Debt – Sinking Funds – Cash) + Total Equity}} = 25\%$$

However, this is a long-term target, which serves as a financial guideline only, not an annual requirement. As a result, the equity ratio floats over time, depending upon actual financial results in any given year, the capital investment program being pursued at the time, and the rates set by the PUB. For example, the equity ratio for the past ten years has been reported as follows:

Table 2. Equity Ratio Performance

2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
13%	15%	19%	20%	27%	23%	27%	27%	26%	25%

Source: Manitoba Hydro, *62nd Annual Report*, year ending March 31, 2013

In addition to the equity target, Manitoba Hydro also attempts to meet two other measures of financial health, which are to ensure that its Interest Coverage Ratio ("ICR") is above 1.2, and that typical capital needs (not including major investments such as generation facilities) can be funded through internal resources.[6] The formula in use for ICR is:

Formula 2. Interest Coverage Ratio Calculation

$$\frac{\text{Net Income + Interest Payments on Debt}}{\text{Interest Payments on Debt}} = \text{ICR}$$

In essence, targeting a minimum ICR of 1.2 means that Manitoba Hydro will organize its affairs – and seek rates from the PUB – consistent with maintaining a 20% cushion of annual cash availability over and above its expected costs of interest.

[5] The 75:25 target ratio was first established in September 1995 by the Manitoba Hydro Electric Board. Please see the response to Information Request MPA/MH I-011a.

[6] The Capital Target is 1.2 times typical capital needs, not including major generation or transmission projects, according to the most recent Debt Management Strategy, April 2012, filed with the PUB as part of the General Rate Application.

Over the past ten years, the company's performance on this measure has been as follows:

Table 3. Interest Coverage Ratio Performance

2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
0.17	1.25	1.77	1.23	1.69	1.49	1.32	1.27	1.10	1.15

Source: *62nd Annual Report*

The notably low performance in 2003-04 coincided with a drought that year, which dramatically affected the company's net income, in fact resulting in losses for that year (since net income was negative, the resulting ICR for the year was below 1.0; ICR can actually be negative itself, if losses in a year are greater than interest payments).

Manitoba Hydro has two sources of capital: internally generated cash flow, and debt. Long-term debt resources are provided by advances from the Government of Manitoba.[7] The Government of Manitoba raises debt from Canadian and international capital markets in the amounts and with the terms and conditions agreed upon with Manitoba Hydro, and then provides that debt on a back-to-back basis, with the addition of a "debt guarantee fee", currently equal to an annual payment of 1% per year on all outstanding long-term debt. Given that the debt is raised by the Government of Manitoba directly on its own account, and then subsequently advanced by the Government to Manitoba Hydro, the Government and taxpayers of Manitoba are directly liable for the full amount of the debt, regardless of the ability of Manitoba Hydro to make good on its annual interest and principal payments to the Government.

Crucially, notwithstanding the fact that the Government of Manitoba raises the required long-term debt for Manitoba Hydro, and on its face this debt is debt of the Province, credit rating agencies and the capital markets do not in practice treat that debt as debt of the province, but rather as debt supported by Manitoba Hydro and its ratepayers.[8] This is a very important element in the calculation of the Province's credit-worthiness, and hence the overall credit rating on provincial debt. This issue will be addressed further below, in section 4 (financial distress).

2.2. Manitoba's Electricity System Resources

Virtually all electricity users in Manitoba are connected to Manitoba Hydro's electricity system.[9] Manitoba Hydro currently serves approximately 550,000 customers, and does so with a generation system amounting to over 5,500 MW peak capacity. More than 90% of the generation resources are

[7] Manitoba Hydro issues a small amount of debt on its own account through Manitoba Hydro bonds, however the vast majority of debt is through Government of Manitoba advances. As per the March 31, 2013 Annual Report, Government advances amounted to $9,775 million out of total long-term debt of $10,012 million.

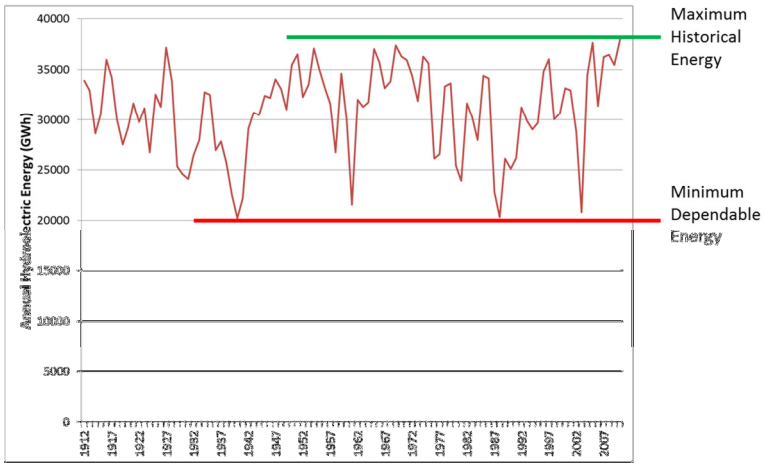
[8] See for example *Credit Analysis of Province of Manitoba*, Moody's Investor Service, July 23, 2013, p. 3: "Roughly one third of the province's total direct and indirect debt is attributed to Manitoba Hydro (issued and on-lent by the province) and is considered to be self-supporting."

[9] A small number of remotely located customers are served through standalone diesel generators.

water powered, which puts Manitoba into a select group of "hydro" jurisdictions, which includes Quebec, British Columbia, Newfoundland & Labrador, Norway, Paraguay, and Iceland.[10]

Like all other predominately water powered systems, Manitoba Hydro must manage the reality of ever-changing annual precipitation. In any given year, water flow through hydroelectric generation facilities can be much higher or much lower, resulting in very different levels of annual energy production. As Figure 5.8 from the NFAT Business Case makes clear, the lowest water flow of the past 100 years was only 47% of average, while the highest year was 168% of average.[11] That is a range of more than 3.5 times the water flow from lowest year to highest year on record. Yet for reasons of reliability, it is only safe to count on the lowest levels as "dependable" energy. If Manitoba's current hydroelectric facilities had been in place over the past 100 years, it might have had the following annual performance (note that this is an illustration only, based on a certain set assumptions about reservoirs, water management, transmission facilities, etc.).

Figure 1. Illustration of Hydroelectric Performance



If the system included no other electricity resources, then it would be necessary to ensure that the minimum dependable energy level was sufficient to satisfy all domestic needs. If Manitoba demand were expected to grow in the foreseeable future to the point that demand would exceed minimum dependable energy, then more hydroelectric generation capacity would be required.

In most years, however, the system will produce more (and in some years much, much more) than the minimum level of energy. Since demand is fairly stable on a short-term basis, all of the excess energy in any given year may be exported to neighbouring jurisdictions, or if possible "saved" by filling up water reservoirs and not producing the energy in the first place.[12] To the extent that existing facilities can

[10] Iceland's electricity system is approximately 75% hydro, and 25% geothermal, which is also renewable and relatively inexpensive. Newfoundland & Labrador is currently building a new hydroelectric generation facility – Muskrat Falls – which, once built, will allow for the closure of the Holyrood oil-fired station, and which will result in the province having an electricity system which is 100% supported by wind and water powered generation.
[11] Data from Figure 5.8 provided by Manitoba Hydro in response to Information Request MPA/MH II-021.
[12] In the event that reservoirs are full, and exports have reached the maximum possible based on transmission line capacity, then remaining water will be spilled over dams and not run through generators.

produce more dependable energy than is needed domestically, then that "extra" dependable energy can be exported through firm contracts to other jurisdictions.

In the case of Manitoba today, the Province is not solely dependent on water power: the electricity system includes two thermal energy facilities (one coal unit, and four natural gas units), two wind power facilities (wind power suffers good and bad years like water power, but generally is not as variable, and on its own schedule, not correlated to water flow), and the ability to import electricity from other jurisdictions. All of this means that total dependable energy is somewhat higher than what can be relied on from Manitoba Hydro's hydroelectric generation facilities.

In order for thermal plants to be maintained in good working order and available when needed, they have to be operated for a small percentage of any week, regardless of whether there is sufficient water power to meet needs. It is the nature of wind turbines that they produce energy whether needed for system purposes or not, so they also increase by a small amount the system's total output every year. Imports, however, need only be purchased when they are needed. The combination of these factors means that total system energy output is always greater than annual water power output, and in years where water is extremely low, other resources ensure that the system's minimum total energy is delivered.

Currently, Manitoba's electricity system has the following output characteristics:

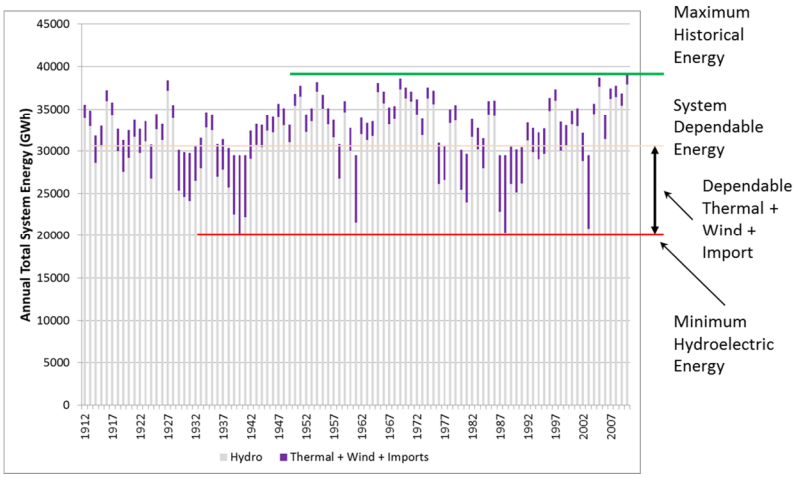
Table 4. Manitoba System Resources

System Dependable Energy	**Energy (GWh)**
Minimum Dependable Water Power	21,950
Dependable Energy from Thermal, Wind & Imports	8,303
Total System Dependable Energy	30,253
Maximum Water Power Potential	38,000 (approx.)

Source: NFAT Business Case, Appendix 4.2; IR MPA/MH II-022

The following chart depicts how Manitoba's current electricity system would have performed if it had been in place over the past hundred years, assuming that demand in every year was equivalent to today:

Figure 2. Illustration of Manitoba Electricity System



In addition to measuring the total annual energy production of the Manitoba electricity system, it is also important to note the peak system capacity: the amount of power that the system can supply at any given moment to all of its customers. Because Manitoba's hydroelectric facilities are supported by a system of reservoirs and water control structures, they can be managed so that they operate at higher power output levels at certain times of the day or year, and at lower power output levels when less electricity is likely to be needed. In this way, even in years with less water flow the system can operate at peak capacity at critical times. Thermal facilities can always generate their peak capacity (unless they are out of service), and usually at short notice. Imports can only be relied upon if firm capacity contracts are in place for expected peak periods of time. Fortunately for Manitoba, the province's peak requirements occur in the winter, while in neighbouring jurisdictions peak requirements occur in the summer, so imports are generally available during Manitoba's periods of peak need. Finally, wind power is unreliable on an hourly basis, so it cannot be counted upon for peak capacity. Currently, Manitoba Hydro's system has the following peak capacity characteristics:

Table 5. Manitoba Peak Capacities

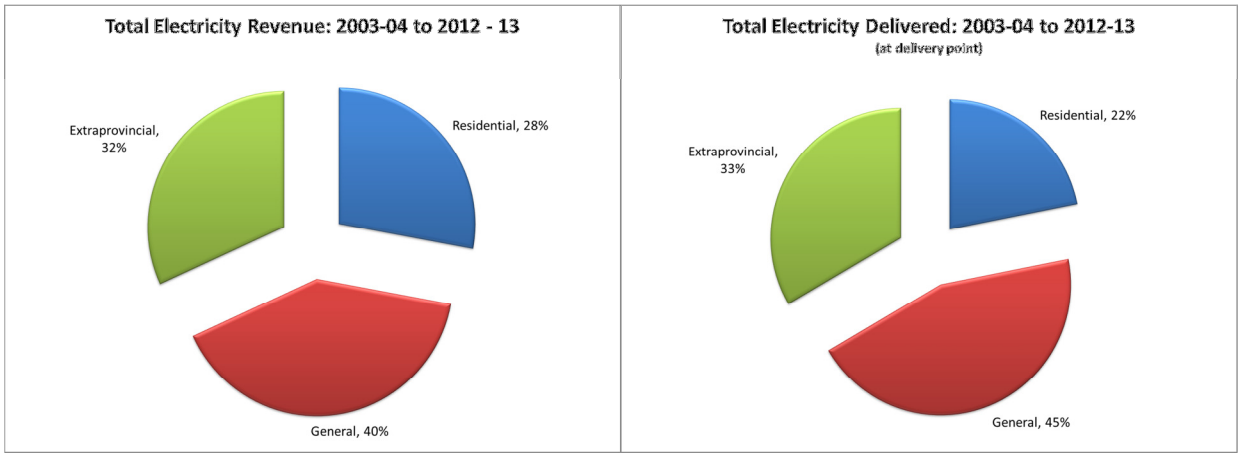
Total System Peak Capacity	**Capacity (MW)**
Hydroelectric Peak Capacity	5,177
Thermal	517
Contracted Imports	550
Total System Peak Capacity	6,244
2012-13 Manitoba Peak Demand	4,535 (approx.)

Source: NFAT Business Case, Appendix 4.2; *62nd Annual Report*

Revenues for Manitoba Hydro consist of the sum total of domestic ratepayer charges, contracted export revenues, and revenues from opportunity exports. Over the past ten fiscal years from 2003-04 to 2012-13, export revenues have represented approximately 32% of total Manitoba Hydro revenues from

electric operations (not including "other" revenues from consulting, etc.).[13] Exports delivered at the Manitoba border equaled approximately 33% of total energy delivered to customers.

Figure 3. Manitoba Hydro Electricity Revenues and Deliveries



Source: *62nd Annual Report*

Since the relative domestic and extra-provincial proportions of revenues and delivered exports was about the same, this means that the price per unit of energy for Manitoba ratepayers (on average for all ratepayers over the ten-year period) was about equal to the price paid by export jurisdictions for power received from Manitoba. *However, it is crucial to note that for Manitoba ratepayers, this was the all-in price for power, whereas customers outside Manitoba had to pay transmission, distribution and other costs in addition to the price paid to Manitoba for the raw energy received*. The result is that Manitoba ratepayers had a total average cost of electricity – including generation, transmission, distribution and all other services - over that ten year period that was much lower than surrounding jurisdictions. This is consistent with the view that electricity costs in Manitoba are relatively very low.

Hydro-Quebec produces an annual survey of electricity costs in twenty-one different cities across North America. They compare the total cost of electricity, before taxes, for seven different customer profiles ranging from typical residential customers to the largest industrial consumers (customers are classed based on monthly energy consumption and monthly peak demand). Winnipeg, and by extension the rest of Manitoba, ranks among the three lowest cost jurisdictions included in the survey in every customer category.[14] This status as a low-cost electricity jurisdiction is a competitive advantage for the province. Critically, in the two categories for the very largest customers, Manitoba is the lowest cost jurisdiction surveyed, with a 5% cost advantage over the next jurisdiction for the largest customer class, and a 10% cost advantage over the next jurisdiction in the second largest customer class.

[13] *62nd Annual Report*, for the year ended March 31, 2013, Manitoba Hydro, data from pages 98-99.
[14] Please see *Comparison of Electricity Prices in Major North American Cities, 2013*, by Hydro Quebec. Available online at www.hydroquebec.com.

2.3. New Resource Needs and Opportunities

Manitoba Hydro has identified that existing electricity resources will no longer be sufficient to meet domestic needs sometime during the mid- to late-2020s. This is claimed for both annual energy production and peak capacity. Moreover, since Manitoba Hydro currently has ongoing contractual obligations for dependable exports, the need for additional resources will occur even earlier.

In Chapter 4 of the NFAT Business Case, Manitoba Hydro describes their Planning Criteria, the history and expectations of demand growth in Manitoba, the past and expected future success of demand-side management programs ("DSM") to curb demand growth, and the resulting timing of the need for new resources.

Other experts retained by the PUB have examined closely the assumptions, methodologies and conclusions relied on by Manitoba Hydro to estimate the growth in domestic demand.[15] To the extent that there is doubt about the near-term expectations for Manitoba demand growth, or the ability of DSM programs to economically curb that growth, it is largely the timing of the need for new resources that would be affected. In the longer-term, however, the assumption that Manitoba demand will continue to increase relentlessly into the future is more controversial, and will be addressed further below in the discussion of risks in section 4.2.2 (Impact of Manitoba Demand).

In addition to growing Manitoba demand for electricity resources, Manitoba Hydro has identified new export opportunities. Several term sheets have been negotiated with counterparties interested in contracting with Manitoba for firm exports of electricity, if – but only if – Manitoba proceeds with new construction of hydroelectric generating stations.

The vast majority of Manitoba electricity exports are destined for utilities in the United States. Manitoba sells a small portion of its available exports to Ontario and Saskatchewan, but in the fiscal year 2012-13 approximately 88% of its export revenues were from sales to the United States.[16]

The Midcontinent Independent System Operator (MISO) is the organization which operates the multi-utility electricity transmission grid into which Manitoba Hydro sells most of its exports. MISO has a peak summer generation capacity of over 100,000 MW, and is many times the size of Manitoba's electricity system when measured by generation resources, customers and total energy consumption. Its resources are based largely on coal and natural gas-fired generation facilities, with a substantial and growing amount of wind power resources.[17] Given its reliance on coal and natural gas facilities which can run almost constantly when needed, the MISO market does not face any shortage of annual power output, but instead planning issues centre on the need to replace retiring coal capacity, and the need to reduce the carbon footprint of electricity output in the future.

[15] Please see reports submitted to the PUB by Elenchus Research Associates Inc. on the load forecast and DSM.
[16] *62nd Annual Report*, p. 49.
[17] Please see, for example, *2012 State of the Market Report for the MISO Electricity Markets*, June 2013; available online at www.misoenergy.org.

Given these characteristics, it is understandable why MISO utilities would only be interested in hydroelectric power from Manitoba: they have their own coal, natural gas and wind resources, and would have no economic need to import those from Manitoba Hydro (in fact, importing them would likely be uneconomic, because it would entail transmission costs to bring power across long distances). On the other hand, hydroelectric energy is carbon-free like wind, but if supplied in the form of a firm energy contract, would be much more reliable, and help them to meet their capacity needs while also reducing their system's carbon output.

Currently, when an export market buys power from Manitoba, it is 90%+ "carbon free", given Manitoba's generation mix. If Manitoba were to build new hydroelectric generation facilities, then its power would still be 90%+ carbon free (in fact, the figure would rise to 95%+). However, if Manitoba builds natural gas-fired facilities, or meets its needs in some other way, then it may no longer be able to claim that it meets that high standard of "carbon free" production. It is not unreasonable to believe, in these circumstances, that if Manitoba Hydro builds additional hydroelectric generation facilities, it would find willing buyers for firm energy contracts – at *some* price – for the sale of a substantial portion of the excess dependable energy that would be expected to be available post-construction.

2.4. Stakeholders and Their Interests

2.4.1. Manitoba Ratepayers

Manitoba Ratepayers benefit from Manitoba's electricity system, but are also obligated to pay all of Manitoba Hydro's costs, less whatever revenue can be earned from exports. Ratepayers are the primary stakeholder in Manitoba's electricity system, and hence in the consideration of Manitoba Hydro's Preferred Development Plan. Ratepayer interests are fairly straightforward to identify: they want safe, reliable electricity services at the lowest possible cost over time. In considering a forward-looking resource plan such as the Preferred Development Plan, however, it is not possible to specifically forecast future costs, because they depend on a great many variables that will only be known for certain in retrospect, as will be discussed much more extensively below. As a result, it is better to formulate ratepayer interests as: safe, reliable electricity services at the lowest possible *risk-adjusted* cost over time.

The notion of *time* also raises complications when considering ratepayers as a collective. Given that the Preferred Development Plan and its alternatives would play out over many decades, and that electricity costs over such a period would necessarily fluctuate, the costs and benefits of any alternative might be distributed differently between ratepayers over the next twenty years, for example, and ratepayers for the subsequent twenty year period, or the period after that. Inter-generational equity between ratepayers is therefore an issue which should be given consideration when reviewing Manitoba Hydro's options. This will be discussed further below, in section 4 (financial analysis).

2.4.2. Government of Manitoba

The Government of Manitoba, on behalf of the taxpayers and citizens of Manitoba, is the sole shareholder of Manitoba Hydro, and hence is also an obvious stakeholder in the decision to be made. The Government's interests, however, are more complex than for ratepayers, and include several priorities:

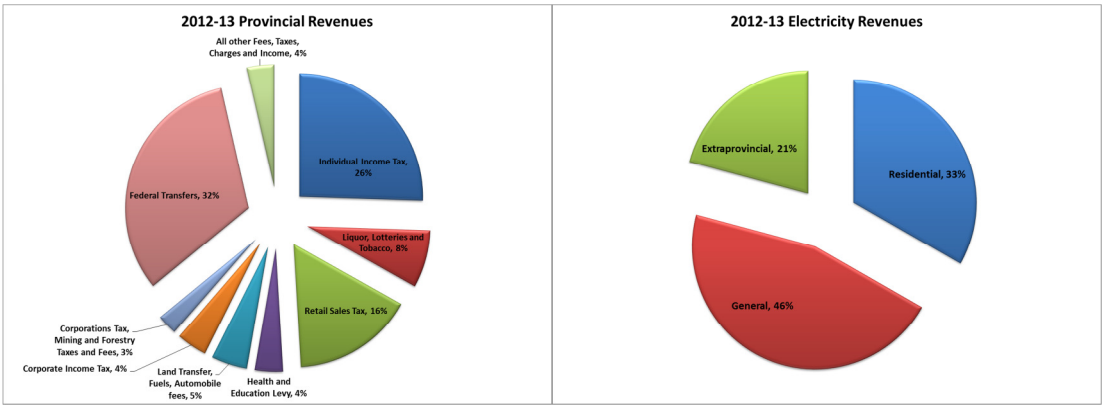
- *Ensure Competitive Electricity Rates*: As has already been noted, Manitoba currently benefits from very low electricity costs as compared to most jurisdictions in North America. This is clearly a competitive advantage for the province, as it may help attract industrial consumers of electricity to the province, who in turn are responsible for jobs and economic development. In addition, since electricity is part of the cost of doing business in every industry – to a greater or lesser degree – keeping electricity costs low generally makes Manitoba businesses more competitive than they would otherwise be. From the perspective of the Government of Manitoba, keeping rates competitive with other jurisdictions is therefore an important goal. However, it is not clear that it is necessarily important for Manitoba to attempt to *maximize* this goal: i.e., to be competitive with other jurisdictions, electricity costs do not need to be "as low as possible", only lower than elsewhere. If rates in other low cost jurisdictions are rising – for example by the rate of inflation – then Manitoba does not harm its competitive position by allowing its rates to rise by a similar amount.

- *Maximize Tax Revenue, Fees and Charges Paid to Government*: Manitoba Hydro does not pay dividends or income tax to the Province, but it does provide several other revenue streams to government. Water "rental" fees are calculated based on the flow of water through Manitoba Hydro's hydroelectric facilities. This is essentially a mechanism for the government to directly capture a fraction of the revenue associated with hydroelectric production. Capital taxes are based on the total equity and debt capital being put to use in Manitoba Hydro. Both of these items are considered operating costs for Manitoba Hydro, and are recovered from ratepayers. All other things being equal, it would be reasonable for the government to prefer options where its revenue streams were greater. For the government, these revenue streams are an alternative form of tax, which benefits the provincial budget. It could be objected that if these taxes were not charged to Manitoba Hydro, then electricity costs would be lower, and the government could simply increase some other tax to compensate. However, it is notable that "ratepayers" are not economically identical to "taxpayers", and hence there is a distributional impact of collecting government revenue through water rentals and capital taxes on Manitoba Hydro.

  As noted in the charts below, individuals and families pay a much larger portion of government revenues (through income tax, liquor/lottery/gaming taxes, retail sales tax, etc.) than they do electricity costs (the Residential customer class provided 33% of Manitoba Hydro's electricity revenues in 2012-13, but personal income taxes and liquor/lottery/gaming taxes represented 34% of Provincial revenues, and then a large share of retail sales tax, land transfer tax and other revenue line items would have to be included). On the other hand, Manitoba businesses and

institutions pay a far greater portion of electricity costs than they do government revenues. Clearly, government could substitute new provincial taxes for the revenue streams that are embedded in electricity costs, and if they did so electricity would become less expensive, but it would not necessarily be a simple substitution.

Figure 4. Taxbase and Ratebase Comparison



Source: Manitoba Estimates, 2013; *62nd Annual Report*

- *Minimize Risk of Default on Guaranteed Debt:* As noted above, the Province of Manitoba guarantees almost all debt incurred by Manitoba Hydro. While the government charges a fee for providing this guarantee, it is a potentially serious burden on the taxpayers of the province. In considering the Preferred Development Plan and its alternatives, a significant issue for government is minimizing the risk that the province would ever be required to make good on the guarantee.

On its face, the legislative requirement that ratepayers cover all costs of Manitoba Hydro (after export revenues are deducted) seems to mean that the government would never be called upon to pay Manitoba Hydro's debts. After all, if Manitoba Hydro needs more revenue to pay its costs, then it can simply request that the PUB raise customer rates. However, in an extreme situation of financial distress for Manitoba Hydro (for example, caused by a prolonged drought), the need to pay debt costs may conflict with the need to maintain competitive electricity rates. For example, if electricity costs were to rise dramatically, implying the need for a substantial rate increase, large manufacturers might threaten to close their doors and move production to other jurisdictions unless the government intervened to provide assistance. If rates were kept low, and Manitoba Hydro simply absorbed the financial losses for a period of years, then Manitoba Hydro's status as a financially self-supporting entity would be called into question. Credit rating agencies, which currently do not include Manitoba Hydro debt as an obligation of the Province of Manitoba, may reconsider that position, at least for a portion of Manitoba Hydro's debt, which could have significant implications for the government. What this illustrates is that despite the legislation under which Manitoba Hydro operates, a situation of financial

distress could force the government to make a difficult political decision. Avoiding the potential for such situations to arise is therefore assumed to be a priority for the government.

- *Maximize Job Creation and Economic Development:* Any infrastructure development plan will entail construction and engineering employment, purchase of supplies, etc., and depending on where that construction occurs, a range of indirect employment and economic development activity that benefits different communities across the province to varying degrees. Maximizing these benefits is an obvious interest of the government in considering the Preferred Development Plan and its alternatives. Not incidentally, the economic activity that is generated by construction of large infrastructure also has secondary benefits in increasing government income and sales tax revenues, as companies and their employees benefit in the form of profits, salaries and wages. However, infrastructure development must be paid for in the form of electricity rates over time, and higher electricity rates can lead to a loss of business competitiveness for the province with an attendant impact on jobs, so the maximization of job creation and economic development over the long-term is a more subtle issue than it immediately appears.

- *Protect the Environment:* Any major infrastructure development will have potential impacts on the environment that must be understood and potentially balanced against other economic and social impacts. In the case of the Preferred Development Plan and its alternatives, very different potential impacts would be felt depending on the choice made. Some alternatives entail direct impacts on land, flora and fauna through flooding, road construction, etc., while other alternatives entail air emissions including carbon, oxides of nitrogen, ground level ozone, etc.

2.4.3. Other Stakeholders

In addition to ratepayers and the Government of Manitoba, three other groups bear mentioning as stakeholders in the decision-making process about the Preferred Development Plan: First Nations, "the environment" as represented by Environmental Groups, and the Federal Government.

- First Nations have partnered with Manitoba Hydro in the past on the development of the Wuskwatim hydroelectric generation facility, and similar arrangements may be expected to apply to the proposed Keeyask and Conawapa facilities. Given the economic benefits that such partnerships could bring to affected First Nations, they have a clear interest in the decision. In addition, since the above facilities are located in lands of traditional concern to First Nations, potential environmental and social impacts should be taken into account.

- Environmental groups often challenge government, business and institutional proponents of large projects with respect to the environmental impacts that a proposed project will engender. With a single-minded focus on protecting the environment, and on understanding and mitigating against potential environmental impacts which may not previously have been brought to light, environmental groups are sometimes a stand-in for "the environment" as an independent stakeholder in a decision-making process.

- Given Canada's constitutional and fiscal relationships, the Government of Canada is often considered to be the ultimate guarantor of provincial credit.[18] Given the debt guarantee provided by the Government of Manitoba to Manitoba Hydro, the Government of Canada can, in some remote sense, be thought of as a guarantor of the debt that would be incurred through the Preferred Development Plan or its alternatives. In addition, the Government of Canada, through its authority over navigable waters, inter-provincial environmental issues, and First Nations, has other, more direct interests in the outcome of the decision-making process.

Notwithstanding the notional importance of these three stakeholder groups, it is fairly clear that their concerns overlap in important ways with those of the Government of Manitoba, even if they may not be perfectly captured. As a result, these additional stakeholder groups will not be included in any further analysis in this report, which will limit itself to considering the interests of the two main stakeholders, Manitoba ratepayers and the Government of Manitoba.

[18] In the *Credit Analysis* cited above in note 7, Moody's Investor Service states on p. 5, "Moody's assigns a high likelihood that the federal government (Aaa, stable) would act to prevent a default by Manitoba. The high likelihood of support reflects Moody's assessment of the incentive to the federal government of minimizing the risk of potential disruptions to capital markets if Manitoba, or any province, were to default, as well as indications of a moderately positive federal government policy stance as illustrated by the flexibility inherent in the system of federal- provincial transfers."

3. Resource Options

In the Business Case, Manitoba Hydro described multiple electricity resources that could be constructed in Manitoba to meet anticipated demand. Furthermore, a variety of alternative combinations and sequences of resources were considered. Many options were discarded because of environmental concerns or legislative restrictions (e.g., coal and nuclear), while other options were not pursued because they are currently prohibitively expensive compared to current Manitoba Hydro rates (e.g., solar). The options which were fully analyzed in the Business Case included various combinations of new hydroelectric stations, natural gas-fired stations, and new transmission interconnections with the United States.

One option that did not appear to be thoroughly addressed in the Business Case was the possibility of largely avoiding new construction through aggressive demand side management programs to flatten the growth of domestic demand, coupled with new transmission interconnections that could provide greater peak import capacity and higher total system dependable energy. In response to intervener and expert consultant requests, Manitoba Hydro is providing additional information to address this possible option, but did not do so in time for the preparation of this report. As a result, consideration of this option was not included here.

3.1. Resource Plans and Individual Elements

In the Business Case, Manitoba Hydro provided descriptions and partial analysis of fifteen Resource Plans, and full analysis including financial models for eight Resource Plans. Each included various combinations and timelines for several potential resources. Of these eight plans, the "All Gas" (Plan 1) and Preferred Development Plan (Plan 14) are the most significant contrasts in overall resource strategy, as they are furthest apart on two orientations: gas vs. hydroelectric, and domestic focus vs. export focus.

Of the remaining six plans that were fully modeled by Manitoba,[19] we dismissed three (plans 2, 7, and 13) because they were essentially similar to other plans, but with less transmission.[20] Even cursory comparison of Manitoba Hydro's analysis of plans having similar generation resources coupled with larger transmission shows the pattern that financial results are superior with additional transmission capacity. This is consistent with received wisdom in resource planning that transmission interconnections provide substantial system benefits.

For the purposes of our analysis, we limited our focus to the following five Resource Plans.

[19] Seven plans were not fully modeled (3, 5, 8, 9, 10, 11, 15) because they were either slight variations on others, or they were demonstrated to be clearly inferior through the first two stages of Manitoba Hydro's analysis.
[20] Plans 2 and 7 include hydroelectric generation but no transmission, and can be contrasted unfavourably to Plans 4, 6, 12 and 14 that all include transmission. Plan 13 includes Keeyask and Conawapa, but only a 250 MW interconnection, whereas both Plans 12 and 14 include a 750 MW interconnection.

Table 6. Resource Plans Examined

Plan	Elements
1	*All Gas* • Single cycle natural gas units are added in 2022-23, 2025-26, 2028-29, 2034-35, 2047-48 • Combined Cycle natural gas units are added in 2031-32, 2037-38, 2040-41, 2044-45
4	*K19/Gas24/250MW* • Keeyask Hydroelectric Station in 2019-20 • 250 MW Transmission Interconnect in 2020-21 • Single cycle natural gas units are added in 2024-25, 2029-30 • Combined Cycle natural gas units are added in 2032-33, 2038-39, 2041-42, 2045-46
6	*K19/Gas25/750MW(WPS Inv.)* • Keeyask Hydroelectric Station in 2019-20 • 750 MW Transmission Interconnect in 2020-21 • Interconnect will be partially owned and funded by a US investor • Single cycle natural gas units are added in 2025-26, 2026-27, 2028-29, 2031-32, 2033-34, 2045-46, 2047-48 • Combined Cycle natural gas units are added in 2042-43
12	*K19/C31/750MW* • Keeyask Hydroelectric Station in 2019-20 • 750 MW Transmission Interconnect in 2020-21 • Conawapa Hydroelectric Station in 2031-32 • Single cycle natural gas units are added in 2041-42, 2044-45, 2046-47
14	*K19/C25/750MW(WPS Inv.)* • Keeyask Hydroelectric Station in 2019-20 • 750 MW Transmission Interconnect in 2020-21 • Interconnect will be partially owned and funded by a US investor • Conawapa Hydroelectric Station in 2025-26 • Single cycle natural gas units are added in 2041-42, 2044-45, 2046-47

Source: NFAT Business Case, Chapter 8

Several basic elements are shared between the above Resource Plans, having the following characteristics when added to the existing Manitoba electricity system:

Table 7. Resource Elements

Resource	Dependable Energy	Maximum Energy	Winter Peak Capacity	Maximum On-peak Exported Energy	Maximum Off-peak Imported Energy
209 MW Single Cycle Gas Turbine	2,460 GWh	2,460 GWh	223MW		
308 MW Combined Cycle Gas Turbine	1,688 GWh	1,688 GWh	325 MW		
Keeyask	3,003 GWh	5,400 GWh	630 MW		
Conawapa	4,650 GWh	7,600 GWh	1,300 MW		
250 MW Intertie	Planning Limits		Depends on contracts	1,144 GWh	208 GWh
750 MW Intertie	Planning Limits		Depends on contracts	3,432 GWh	3,120 GWh

Source: NFAT Business Case, Chapter 7; SPLASH model outputs provided by Manitoba Hydro

The five Resource Plans selected, with their various combinations and timing of resource elements, allow for comparisons of financial performance over time between versions of the Manitoba electricity system with characteristics along several dimensions: Gas/Hydro; Less/More Interconnection; Domestic/Export Focus; Earlier/Later Construction.

- Gas/Domestic Focus vs. Hydroelectric/Export Focus: Plan 1 vs. Plan 14
- Less Interconnect/More Domestic Production vs. More Interconnect/Less Domestic: Plan 4 vs. Plan 6
- Earlier Hydro construction for Firm Export vs. Later for Domestic: Plan 14 vs. Plan 12
- Hydro/Gas vs. Hydro/Hydro: Plan 4 or 6 vs. Plan 14

3.2. Notable Features

3.2.1. Contrasting Impact of Resource Elements

Natural gas generation resources increase the system's dependable energy, but are unlikely to affect maximum annual energy production to a significant degree. In "wet" years, Manitoba Hydro's existing hydroelectric generation facilities are more than sufficient to satisfy domestic needs and create a

surplus for export. In such years, gas generation facilities will operate to the minimum extent. In "dry" years, natural gas units have the effect of increasing substantially the minimum system dependable energy, as well as contributing to peak winter capacity.

Hydroelectric generation resources increase both the system's dependable energy, AND the maximum energy possible in any given year, therefore driving up the average exports that should be expected from the system. Hydroelectric generation facilities therefore are inherently "export-oriented", and beg the question of the electricity system's transmission capacity for export (if there is insufficient export capacity, then in "wet" years water might have to be spilled/wasted).

Transmission interconnections potentially provide benefits for meeting peak capacity needs (if coupled with firm import contracts), and increase the ability to import power in "dry" years and export it in "wet" years. They are multi-purpose resources and can contribute in a variety of ways to system financial performance over time.

3.2.2. Long Term Plan but Near Term Differentiation

All fifteen Resource Plans proposed by Manitoba Hydro include natural gas-fired generation elements, though in some cases not until the 2040s. While in Chapter 7 of the Business Case Manitoba Hydro identified a number of other potential hydroelectric projects in the province,[21] they make no suggestion that any of these could be practical parts of current planning, because based on the stage of current project development and relative prices, they are uneconomic. However, it is notable that there is mention of the possibility that in the future several hydroelectric projects could be combined to create a more competitive alternative.[22] This suggests that choice of a Resource Plan today, such as the Preferred Development Plan (which only includes natural gas-fired generation in the distant future), could later be revisited in light of the opportunity to pursue additional hydroelectric energy. Similarly, even plans which indicate natural gas both immediately and in the longer term could be revisited at any time in the future if it is determined that hydroelectric options have become more attractive.

In short, while the Resource Plans are structured as long term multi-stage projects for the purposes of analysis, their true value is in highlighting the potential longer term implications of resource choices made in the near future. It should be assumed that all Resource Plans are subject to revisit and modification as they unfold.

3.3. Planning Variables

All electricity resource planning exercises entail risks, because they depend very much on future conditions, which are ultimately unknowable in advance. It is highly unlikely in any jurisdiction that there is a choice that is universally superior to all other options in all possible future conditions. Instead, the challenge is consider a wide variety of possible future conditions, and determine if each alternative is

[21] Please see Business Case, c. 7, pages 23 to 28.
[22] Ibid., p. 28.

robust in the way it performs across them. Results of such analysis would indicate the costs, benefits and risks that would be accepted by stakeholders if that option were chosen.

Manitoba Hydro has carefully screened its resource alternatives on the basis of safety and reliability standards. All of the options examined in detail in the Business Case passed those tests. As a result, the expected future performance of the *physical* electricity system is not an issue in the selection among options: all of the options considered would satisfy Manitoba's electricity needs safely and reliably according to the standards and criteria in place in Manitoba. What is at issue is the expected *financial* performance of the various resource options under future conditions that might obtain. There are a number of factors which affect Manitoba Hydro's financial performance, and which will vary in the future, in ways that are increasingly unpredictable further out in time. To the extent possible, testing the resource options consists of imagining plausible future paths for these variables, and calculating how the resource plan would perform in that possible future.

3.3.1. Manitoba Demand

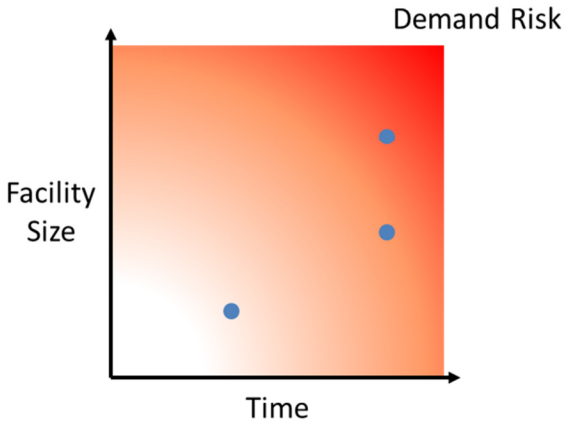
The Preferred Development Plan and its alternatives were created because of a perceived need for new resources. The timing of that need, however, depends very much on the rate of demand growth in Manitoba. If demand growth is relatively high, then new resources will be required sooner, and if relatively lower, then later. The difference can amount to a few years, according to the analysis presented by Manitoba Hydro. One risk is that capital will be spent earlier than necessary, which means that a facility will not be fully utilized for a period of time. This loss of efficiency would be costly to ratepayers, but likely only temporarily.

Considering the different options, the risk of being incorrect about the timing of the requirement for new resources is in some measure proportional to the time required for development and construction of a new facility. For example, a natural gas-fired generation facility may take three years to build and put into service, while a hydroelectric facility may take five to seven. Given uncertainty in demand growth, the further out in time the projection is, the greater the likelihood for error. From this perspective, facilities which can be constructed more quickly have an advantage, because they can be more accurately targeted to the timing of needs.

Over the longer-term, however, the more important risk with respect to demand growth concerns the size and longevity of proposed resources. Large, extremely long-lived resources are susceptible to becoming "stranded assets": facilities which are built to serve a need which never fully materializes, and are therefore inordinately expensive for the purpose they ultimately serve. In the case of electricity resource options in Manitoba, this risk would be expressed in the case of Keeyask or, more likely, Conawapa, where the risk is that domestic Manitoba demand growth in the future could stall long before an additional 1,300 MW of capacity and 5,000 GWh of energy are fully required. The reasons for a long-term change in direction could be many, but most easily conceived of are some change in technology which allows consumers to dramatically reduce their consumption (e.g., a new cooling technology).

It is important to note, however, that "demand" need not specifically apply to Manitoba domestic demand. A new hydroelectric generation facility in Manitoba could, if Manitoba demand is lower than anticipated, simply serve export demand. However, from a financial perspective Manitoba ratepayers would then in effect be investors in a pure export project, rather than electricity consumers of a necessary facility which may for a time be larger than needed.

Figure 5. Demand Risk and Electricity Infrastructure



Gas plants, with a much shorter typical life of only twenty-five years and flexibility in size (smaller units can be built singly or in multiple sets, as required), do not suffer nearly to the same degree from demand risk. Transmission resources, with an average life between the two types of generation facilities, occupy a middle level of risk, also mitigated by the fact that they are flexible enough to serve several different purposes depending on need (i.e., winter peak capacity, higher exports in "wet" years, higher imports in "dry" years, etc.).

3.3.2. Fuel Availability/Hydrology

Electricity generation plants require inputs – or fuel – to operate. In the case of hydroelectric facilities, this fuel is water that derives from precipitation in relevant watersheds. For thermal plants, that fuel will be coal, natural gas, diesel fuel or some other hydrocarbon or biomass. Fuels for wind turbines and solar panels are self-explanatory.

Manitoba Hydro did not explicitly address hydrology/fuel availability in their financial modeling, except to test the sensitivity of the Resource Plans to a prolonged drought. They assumed that natural gas was available upon request for any number of new facilities. This is now probably a fair and reasonable assumption, given the existing identified natural gas resources in North America (note that ten years ago, before the "shale gas revolution", many analysts believed that North America might run short of

recoverable natural gas resources, and be forced to import liquefied natural gas, which would have represented real concerns about availability).[23]

Critically, Manitoba Hydro assumed average hydroelectric performance in every year throughout their models.[24] This allows them to consider factors which are longer-term than the annual swings in precipitation that lead to more or less hydroelectric generation.

However, review of the information on historical water flows supplied by Manitoba Hydro in the NFAT Business Case Figure 5.8 suggests that changes in water flows can have an impact beyond any one-year or short-term period. For example, on a five-year basis, average water flow has ranged from 70% of average to 130% of average. On a ten-year basis the range narrows only slightly to 80% to 120%. Even on a twenty-five-year basis the range of averages is 90% to 110%. Given that Manitoba is so heavily dependent on hydroelectric energy currently, and will continue to be so for an extended period even in the All Gas Resource Plan, understanding the impact of hydrology on the choice of Resource Plan appears to be potentially important.

3.3.3. Fuel Prices

The price of water as a "fuel" for hydroelectric facilities is set by the government, in the form of the water rental fee. This fee has been stable, and is assumed to continue at its current level for the foreseeable future. To take into account the general increase in prices, it is prudent to assume that the water rental fee will rise by inflation in the more distant future. However, the Government of Manitoba could change the water rental fee at any time of its choosing, which would have an impact on the relative attractiveness of hydroelectricity.

Natural gas prices are extremely volatile, and a review of prices over the past twenty years demonstrates the degree of uncertainty that should be placed on any forward estimates. From the perspective of Manitoba Hydro's production costs, however, fuel prices are not currently very important to financial results. Natural gas-fired generators are a small part of Manitoba generation capacity, and even in the All Gas Resource Plan it will take many years for the system as a whole to become very sensitive to natural gas prices. However, ultimately the balance between hydroelectricity and natural gas-fired electricity would shift significantly enough that fuel prices would have a stronger impact on net income.

Another expert consultant to the PUB has commented on the natural gas price assumptions adopted by Manitoba Hydro, not because of the role of natural gas prices in Manitoba's production costs, but because of the impact of natural gas prices on the next variable addressed.[25]

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[23] See for example the International Energy Agency *World Energy Outlook 2013* for a discussion on natural gas availability. Also see the *BP World Energy Outlook 2035*, or the United States Energy Information Administration *Annual Energy Outlook*.

[24] The average chosen is the average hydroelectric output that would result from the application to the planned hydroelectric facilities in each Resource Plan of the water flows of the past 99 years. In other words, assuming that a Resource Plan contemplated no new hydroelectric facilities, and the continued maintenance and repair of all existing facilities, then approximately 31,000 GWh of annual hydroelectric production would be assumed.

3.3.4. Export and Import Prices

As noted above, over the past ten years Manitoba Hydro delivered a third of its electricity (measured at delivery point) to export markets, largely because the province's hydroelectric generation facilities were producing far more power than was domestically required. At the same time, it improved the financial value of its system by importing power at off-peak times while holding back hydroelectric generation, and then sold power into export markets at peak value times. When needed, especially in the drought year 2003-04, power was imported in large volumes to compensate for diminished hydroelectric production.

Prices paid per MWh of electricity by export customers are fundamental to the value of all of these transactions, and those prices change over time. A certain portion of these sales were through firm contracts, where prices are fixed for the term (generally rising with an inflation and/or other index), but a majority was exposed to whatever price was prevailing in the market. Given the destination for the vast majority of Manitoba's export electricity, the relevant market is the MISO market in the United States.

Prices in the MISO market are fundamentally out of Manitoba's control. MISO is a much larger system, and its supply and demand dwarfs that of Manitoba. At certain times Manitoba's transactions may have an impact on the marginal price in the market (especially regionally, where system congestion effects become important), but Manitoba is essentially a price taker. Another independent expert consultant retained by the PUB has commented in detail on the assumptions and expectations about future MISO prices.[26]

As noted above, building hydroelectric facilities as part of the chosen Resource Plan has the net effect of making Manitoba Hydro's financial results more dependent on export results, whose value will in turn be determined by both the quantity and price. Testing the Resource Plans with respect to a range of potential export/import prices over time is critical to estimating future impacts of the choice being made.

3.3.5. Construction Costs

Until a project is completed, its costs can be estimated, but not known. Given the size of some of the projects being considered, measured both in dollars, complexity and time required for development and construction, the risks associated with construction can be significant.

Manitoba Hydro appears to have made every effort to carefully estimate the cost of constructing different resources, while putting ranges around them to allow for testing of the financial consequences if errors are made. Another independent expert consultant retained by the PUB has provided

[25] Please see the report to the PUB of Potomac Economics.
[26] Ibid.

commentary on the construction cost assumptions made by Manitoba Hydro, and the price ranges that they have assumed.[27]

It is important to note, however, that despite the best efforts of proponents, large construction projects do sometimes go horribly wrong. History includes cautionary tales such as the Darlington Nuclear Plant in Ontario (195% over budget), the "Big Dig" in Boston (190% over budget), the Channel Tunnel (80% over budget), and the Denver International Airport (70%), among many others. Hydro dam projects have faced similar situations on occasion.

More recently and locally, the construction of the Wuskwatim hydroelectric facility in Manitoba suffered from substantial cost increases because of the unexpected rise in prices for commodities such as cement and steel, and the spike in labour and engineering costs driven by infrastructure spending across Canada and the rest of North America.

As a result, it is important to test the performance of Resource Plans in the face of different construction cost scenarios.

3.3.6. Cost of Capital

Manitoba Hydro's capital is a combination of retained earnings and debt. Retained earnings are driven in part by the rates approved by the PUB for electricity in Manitoba, which nominally should include a "return on equity" component in order to ensure that Manitoba Hydro actual earns net income that can be retained.

As noted above, Manitoba Hydro depends on the Government of Manitoba to raise debt from Canadian and international capital markets. Manitoba faces the prevailing rates of interest, and has no control over them over time (except insofar as the Province's state of finances affects its credit rating and hence the premium that must be paid compared to riskless debt instruments). Equity rates on regulated entities are typically set in relation to interest rates. Since interest rates are themselves affected by the general inflation rate, all of these factors often move in concert.

From the perspective of calculating the performance of Resource Plans in the future, various combinations of debt, equity and inflation rates should be tested, as these can have profound impacts on financial performance.

[27] Please see the report to the PUB of Knight Piésold Consulting.

4. Financial Analysis

The five selected resource plans were tested using a financial model.

4.1. Model Design and Construction

The following information from Manitoba Hydro formed the basis of the model:

- Outputs from the SPLASH model for each of the five Resource Plans under various assumptions about energy prices, Manitoba demand, the physical performance of the assets assumed in each Resource Plan, and 99 alternative hydrology patterns based on historical water flows;
- Information on Manitoba Hydro production costs and overhead costs consistent with each of three scenarios for economic variables, including inflation rates, exchange rates with the United States, and interest rates; and
- Information on capital costs for the resource elements in each plan, consistent with the three scenarios for construction costs, and the three scenarios for economic variables assumed by Manitoba Hydro.

In addition, we relied upon – except where specifically noted – the analysis of Manitoba Hydro with respect to the probabilities of occurrence of each of the twenty-seven scenarios suggested for combinations of energy prices, economic variables and construction costs assumed by Manitoba Hydro.

Critical assumptions and calculations in the model include:

- Manitoba electricity rates are treated as a combined, average rate per unit of electricity, with no differentiation between very large, general service or residential customers;
- Annual electricity rate changes for Manitoba domestic customers were restricted to not more than two times the rate of inflation in the economic scenario tested;
- The discount rate used to calculate the present value of cash streams over time was not the weighted average cost of capital used in the scenarios, but was instead either 6% or 10%, corresponding to either a lower or higher “time value of money” for ratepayers;
- The model ends after 48 years (because that is the extent of the data available), and no “terminal value” has been added to try and capture the future beyond that point; instead, specific discussion below will address this issue.

The model produces a full set of income statement, balance sheet, cash flow statement, and regulated rate calculations for Manitoba Hydro from the years 2014-15 to 2061-62.

The model was run over 3,000 times in total, so that multiple runs could be performed on each set of variables chosen by Manitoba Hydro, in combination with a variety of different hydrological patterns.

For additional information on the model, please see Appendix C (Tables of Results of the Present Value of Domestic Revenue).

4.1.1. Note on Uncertainty and Precision

The financial model produces outputs with a high degree of precision; in fact, to a practically infinite number of decimal points. This characteristic should NOT be confused with accuracy. It is simply the nature of mathematical operations that they result in precise outputs.

The model extends out almost 50 years from today. Included in the calculations are projections for prices and growth rates which are in many cases merely straight line extensions into the future of near term assumptions. A slight change in growth rates of certain variables could cause dramatic swings in outcomes, which is why a variety of such growth rates are tested. Similarly, in order to produce results that are "probability-adjusted", Manitoba Hydro assigned likelihoods to different scenarios. Giving a different weight to scenarios would change the probability-adjusted results.

All of this suggests that small differences in model outputs should be regarded with skepticism. The value of such models is in illuminating patterns and highlighting gross differences where they exist.

4.2. Findings on Ratepayer Total Costs

Minimizing risk-adjusted cost over time is the primary interest of ratepayers, after the maintenance of a safe and reliable electricity system.

The financial model calculates the annual payments that Manitoba ratepayers are presumed to make in the future, under each specific set of assumptions and each tested hydrological pattern. In order to meaningfully compare streams of cash flow that fluctuate over time, a discount rate is applied to result in a present value as of the first day of the model (April 1, 2014). In addition, Manitoba Hydro's probability weightings are applied to each set of future conditions, and the results from each set of conditions is then blended based on these weightings.

This process results in the following:

Figure 6. Risk-Adjusted Present Value Cost to Ratepayers

Average Probability Weighted PV of Domestic Revenue
High, Ref and Low Economics
($ in millions)

	Development Plan				
Economics Scenario	**1**	**4**	**6**	**12**	**14**
NPV @ 6.00%					
Reference	$43,912	$43,286	$43,699	$45,390	$44,949
High	$54,201	$53,109	$53,632	$55,632	$55,483
Low	$35,873	$35,121	$35,341	$35,866	$35,532

Average Probability Weighted PV of Domestic Revenue
High, Ref and Low Economics
($ in millions)

	Development Plan				
Economics Scenario	**1**	**4**	**6**	**12**	**14**
NPV @ 10.00%					
Reference	$23,662	$23,593	$23,759	$24,448	$24,343
High	$27,728	$27,886	$28,142	$29,361	$29,550
Low	$20,037	$19,832	$19,906	$20,092	$20,010

Each column in each of the two matrices represents an estimate of 48 years' worth of Manitoba ratepayer costs for the identified Resource Plan. Each matrix has three rows, corresponding to the assumptions made about economic variables, a group which includes inflation, interest rates, and Canada-US exchange rates. The first matrix uses a discount rate of 6% to calculate present value, while the second matrix uses a discount rate of 10%.

Each of the figures represents a probability-weighted average of 189 model runs (i.e., for each of nine different sets of variables, the model was run for 21 different hydrological patterns, then the 48-year stream of domestic revenues in each of the 189 runs was discounted to the present by the discount rate).

The first thing that should be notable is that the range of figures in each matrix is more similar to each other than to the other matrix. Discount rate, representing the time value of money, is extremely powerful, and overwhelms all other distinctions. Since discount rate is a reflection of the average

assumed "time value" of ratepayer money, it does not make sense to combine these figures, but rather to consider each matrix separately.

The second notable fact is that within each matrix, rows of numbers are closer to each other than columns of figures are. This makes clear that the assumptions made about economics, and particularly the inflation rate, overwhelms any difference between Resource Plans. In other words, assuming an average of 2% inflation over 48 years instead of 3% makes a bigger difference to the outcome than choosing one Resource Plan over another. Since inflation over the next 48 years will average either 1%, 2% or 3%, but will not be all three simultaneously, it does not make sense to combine these rows of numbers, but rather consider them separately.

A third fact, less instantaneously obvious, but nevertheless easily calculated, is that within each row, the deviation from the mean of the row is not more than 2.5%. This means that regardless of the Resource Plan chosen, *the model results in total risk-adjusted present value costs to ratepayers over a 48-year period that are all within a maximum of 5% of each other*. In many ways, this is a remarkable result. The Resource Plans are radically different in their choices of infrastructure elements, use of fuels, orientation towards exports, etc., and yet the differences do not appear to translate beyond the marginal. However, it should be recalled that Manitoba Hydro's existing resources total more than 5,500 MW of peak capacity, with maximum annual energy output of more than 38,000 GWh. In the first fifteen years of the five resource plans, between 700 MW and 2,000 MW of peak capacity is added, and maximum system energy is increased by anywhere from 0 GWh to 13,000 GWh. In other words, since the existing electricity system, dominated by hydroelectricity, continues to be the majority of the system for a very long time to come despite the choice of Resource Plan made, it should not actually be surprising that the incremental Resource Plan choice does not have an overwhelming impact on total costs to ratepayers.

There is another contributor to this outcome, however, which can only be discovered through analysis of raw model outputs: prior to the implementation of any of the Resource Plans, the existing system is taking on a substantial amount of debt as a result of system investments (including Bipole III, the most significant single component). This is a particularly heavy burden to bear for the All Gas Resource Plan (1), because that plan is the least export oriented, and hence the least likely to generate "extra" revenues that could help to quickly amortize those debt burdens. For the higher capital plans, the existing debt burdens are less severe compared to the debt burdens being assumed as part of the resource plan itself, and the export orientation also provides much higher net income to compensate for the overall debt burden, and hence differences between the plans which might otherwise have been starker are somewhat muted.

A third factor contributing to the lack of difference between the outcomes of the Resource Plans relates to the treatment of sunk costs in the Keeyask and Conawapa projects. In the All Gas Plan (1), all spending to date on the proposed hydroelectric facilities is written off. For ratepayers, this amounts to an incremental debt burden which must be retired, without any compensating benefits (in the other plans, since the facilities are actually built the sunk costs are an investment with associated benefits, as opposed to a loss to be written off). This fact is inescapable, because real dollars have been spent and

must be recovered from ratepayers. However, the reality of the sunk costs does tend to moderate the differences between the 48-year outcomes of the Resource Plans.

A final observation to make on the matrices is the rank ordering of Resource Plans from lowest ratepayer cost to highest ratepayer cost:

Figure 7. Rank Ordering of Resource Plan Cost to Ratepayers

Discount Rate	**Economic Variables**	Lowest				Highest
6%	Reference	4	6	1	14	12
	High	4	6	1	14	12
	Low	4	6	14	12	1
10%	Reference	4	1	6	14	12
	High	1	4	6	12	14
	Low	4	6	14	1	12

From this rank ordering, some patterns begin to emerge:

- Resource Plans 4 and 6, which include Keeyask, some level of transmission interconnection and natural gas plants, appear to fare consistently better than the other options
- Plans 14 and 12, which include Conawapa, are consistently ranked as more costly to ratepayers than Plans 4 and 6, which include Keeyask but not Conawapa
- Plan 1, the All Gas Plan, ranks poorly when economic variables such as inflation and interest rates are low, but better when they are moderate or high; this is particularly true with respect to the Preferred Plan 14, which is superior to All Gas in the low economics environment but not otherwise
- Plan 1, the All Gas Plan, ranks relatively poorly when the discount rate is lower at 6%, but better when the discount rate is higher at 10%, suggesting that the relative time value of money is an important consideration
- Plan 4, with a 250 MW interconnection, always ranks better than Plan 6, with a 750 MW interconnection; however, returning to the figures themselves it is notable that these two plans are never more than 1% apart from each other in any of the cases
- Similarly, Plan 14 is better than Plan 12 in every case but one, suggesting that an earlier construction and export orientation for the Conawapa facility is better than a later one; however, the difference between these plans is also always less than 1%.

These are patterns and inferences that are drawn based on "probability-adjusted" weighting for groups of possible futures, according to the weights assigned by Manitoba Hydro. In reality, however, only one set of variables will be closer to the true 48-year average. In Appendix C (Tables of Results of the Present Value of Domestic Revenue) the outputs for the model runs for each of the 27 future scenarios have been provided. In each of the 27 scenarios, the domestic revenue results of the 21 hydrological runs have been listed, including high, low and average results, as well as the standard deviation (i.e., there is a two-thirds probability that results will be within one standard deviation of the average, assuming that hydrology is distributed on a normal curve over time, which is the typical assumption). For reference, Manitoba Hydro's calculated "percentage likelihood" for each of the 27 scenarios is also shown.

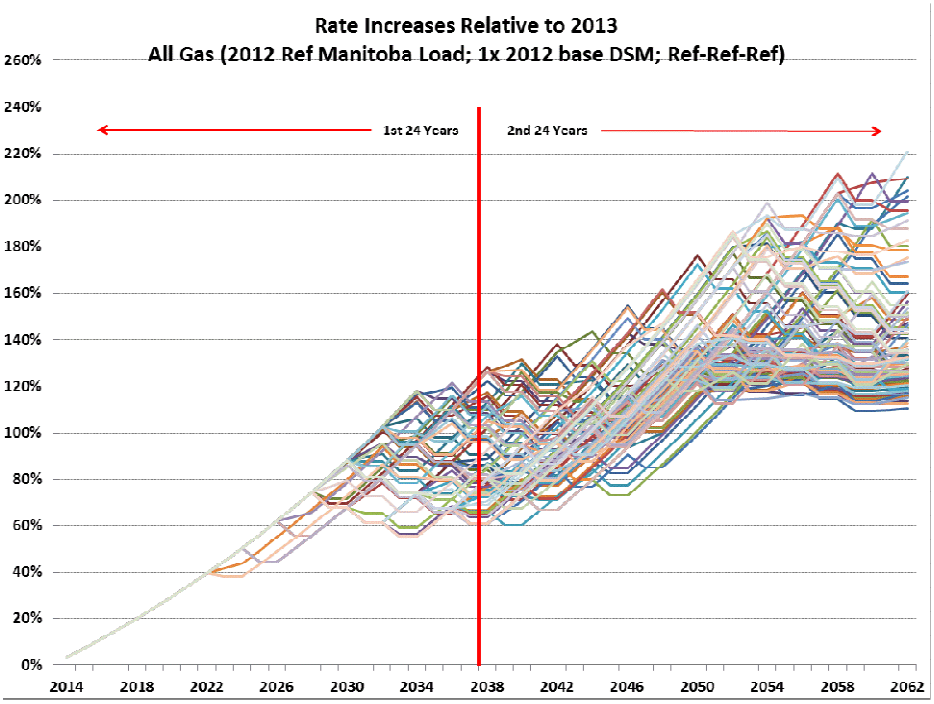
Based on these results, hundreds of other rank orderings of the Resource Plans can be calculated, depending on the scenario examined and the discount rate chosen. In addition, a sense of the impact from some of the possible 35-year hydrology patterns can be understood and compared with the impact of scenario choices.

4.2.1. Time Value of Money and Rates

One of the observations from the rank ordering of the present values of the ratepayer costs was that the ranking of the All Gas Plan, and other Plans, appeared to change depending on the discount rate assumed. To investigate this further, it is useful to examine the expected course of rate increases under the different Resource Plans. Since Manitoba demand is relatively similar across the Resource Scenarios, the pattern of rates essentially indicates the pattern of revenues.

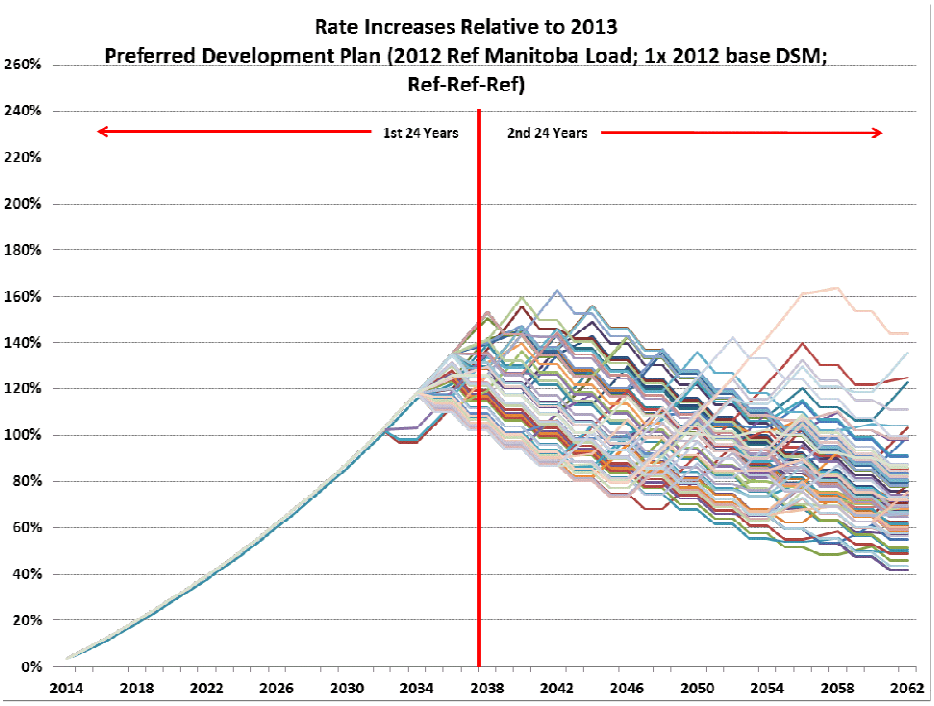
The following chart depicts the pattern of rate increases that results from 99 different hydrological patterns, in a single combination of future variables (Reference economics, Reference energy costs, Reference construction costs), for the All Gas Plan 1.

Figure 8. Rate Increases Relative to 2013 (All Gas)



Next is the same set of runs applied to the Preferred Development Plan 14.

Figure 9. Rate Increases Relative to 2013 (Preferred Development Plan)



Note that both of these depictions assume the same interest rates and inflation rates, the same prices for fuels and exported power, and the same costs of construction materials and labour. They also each depict the same 99 hydrological patterns. The only difference is the choice of Resource Plan, and hence the selection and timing of construction of different electricity resources.

The difference between the two plans could not be made more starkly obvious.

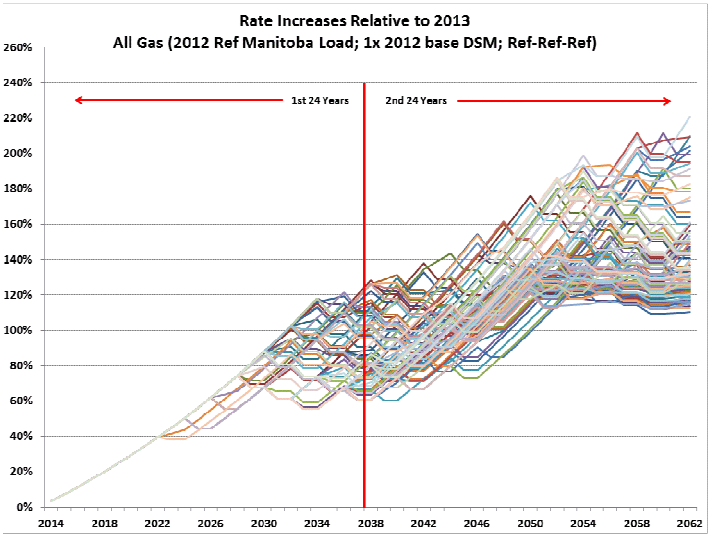
The All Gas Plan consistently imposes the maximum allowable rate increase (set at two times inflation, which is 1.9% per year in this set of variables, resulting in rate increases of 3.8% per year) for the first ten years of the model. After that point, if there are exceptionally "wet" years, the rate increases can in some cases be moderated. By the 2030s, the impact of hydrology can be felt annually, but a general upward trend in rates is seen for the rest of the model, and in particular for the second half of the time. At the mid-point, rates are up anywhere from 60% to 120% compared to 2013. By the final year, rates are up between 110% and 220%.

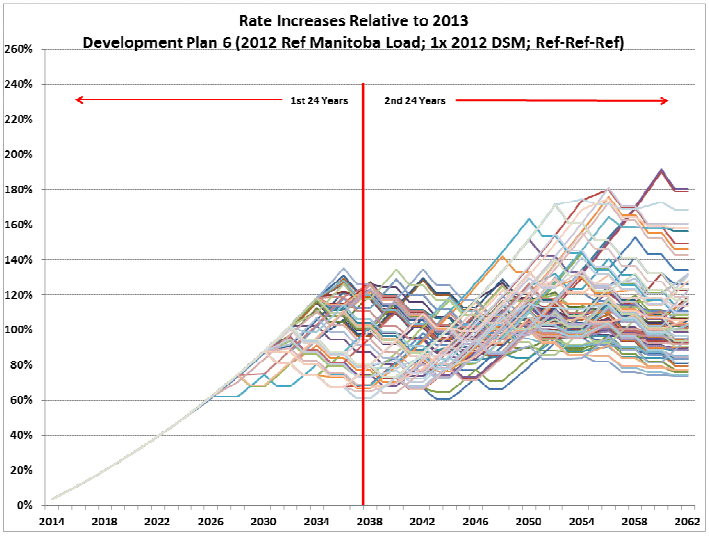
The pattern for the Preferred Development Plan is very different. Maximum rate increases are applied until 2032, when they reach 100% above 2013 rates. Hydrology effects begin to be felt at that point, because rates have reached a level high enough to financially sustain the company. By the mid-point, rates are between 100% and 150% higher than 2013. However, after that point rates actually trend downward, with only a few very "dry" hydrological situations driving up rates in the late period. By the end of the model, rates are between 40% and 140% higher than 2013.

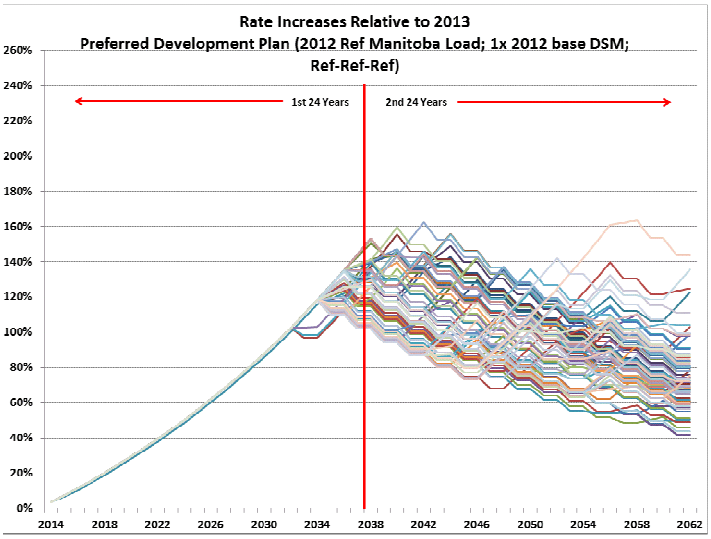
This pattern exemplifies the issue of "time value of money". In the All Gas Plan (1), the first "generation" of ratepayers faces rate increases, but those rate increases are less prolonged and severe than the rate increases expected in the Preferred Development Plan (14). However, for the second "generation" of ratepayers the situation would be reversed, according to the model. If ratepayers have a strong preference to save now and pay later (i.e., they have a high discount rate such as 10% or more), then they would prefer the pattern of the All Gas Plan (1). However, if they are willing to make a sacrifice in the near future to reap sizeable rewards later on (i.e., they have a low discount rate like 6% or less), then they might choose the Preferred Plan (14).

As might be expected, Resource Plans (4) and (6) have patterns that are somewhat between these two extremes. On the next page, the charts for Resource Plans (1) and (14) are repeated, with the chart for Resource Plan (6) placed in between for comparison.

Figure 10. Rate Increases Relative to 2013 (All Gas vs Preferred Development Plan vs Plan 6)







Consideration of these rate patterns also points to the issue of the future beyond the 48th year of the model. If the model were extended out even further, for example for another full twenty-four years (another "generation"), a few additional observations would be warranted:

- The Preferred Development Plan (14), and Plan (12) which also includes Conawapa, would produce lower ratepayer costs than would any of the other three Resource Plans, none of which include Conawapa

- The present value of that presumed set of additional results would be much higher if it were discounted at the low rate of 6% rather than the higher rate of 10%; at a discount rate of 10%, the total value of all years beyond 48 would be less than one twentieth of the total value of the first 48 years; whereas at a 6% discount rate, the total value of years beyond 48 would be several times greater

- For every year the model is extended beyond 48, the more the rank orderings of the Resource Plans will change in favour of Plans 14 and 12, particularly with the lower discount rate of 6%; however, with the higher discount rate of 10%, the shifting of the rank ordering will slow down and eventually stop because of the rapidly declining importance of those future years.

With respect to the issue of time value of money and the varying rate patterns displayed by the Resource Plans, it should be recalled that:

- The second half of the 48-year time period is inherently more uncertain than the first half, in the sense that future conditions are harder to predict so far in advance: technology is always changing, economic growth patterns change, climate may be changing, etc., so making accurate predictions about any variables (fuel costs, export costs, construction costs, the efficiency of equipment in the future, etc.) is that much more difficult;

- On the other hand, some things are undeniably knowable from today's standpoint, such as that waterpower is a very inexpensive "fuel", so that *at some point* facilities like Conawapa always become very attractive assets for ratepayers of the day; an important question is whether ratepayers today and in the near future do or should care about the welfare of ratepayers decades away.

4.2.2. The Impact of Manitoba Demand

All of the analysis to this point has assumed a single pattern for the electricity demand of Manitoba ratepayers in the future. However, as has been noted above and by others, there is considerable uncertainty about what Manitoba demand will actually be, particularly as decades pass.

Manitoba Hydro provided raw SPLASH data for the performance of the electricity system in high and low demand alternative futures for both the All Gas Plan (1), and the Preferred Development Plan (14). When this data was applied to the financial model, the following results for ratepayer costs resulted:

Figure 11. PV of Domestic Revenue (All Gas vs Preferred Development Plan)

PV of Domestic Revenue
Ref Economics, Energy and Capital
(full hydrology regime of 99 years)
($ in millions)

	All Gas			Preferred Development Plan		
	Manitoba Load (2012)			Manitoba Load (2012)		
	Ref	High	Low	Ref	High	Low
NPV @ 6.00%						
Average	$43,675	$43,595	$43,838	$44,073	$44,207	$44,197
Maximum	$45,530	$45,256	$45,711	$46,123	$46,591	$45,811
Minimum	$41,724	$41,648	$41,884	$42,155	$41,649	$42,123
Standard Deviation	$783	$770	$798	$952	$997	$1,031

PV of Domestic Revenue
Ref Economics, Energy and Capital
(full hydrology regime of 99 years)
($ in millions)

	All Gas			Preferred Development Plan		
	Manitoba Load (2012)			Manitoba Load (2012)		
	Ref	High	Low	Ref	High	Low
NPV @ 10.00%						
Average	$23,548	$23,795	$23,241	$24,110	$24,542	$23,550
Maximum	$24,278	$24,436	$23,788	$24,779	$25,474	$23,985
Minimum	$22,839	$22,852	$22,580	$23,497	$23,233	$22,967
Standard Deviation	$365	$417	$295	$317	$458	$290

What these matrices depict is the performance of the two Resource Plans in a single set of future variables (Reference interest rates, Reference fuel costs and export prices, Reference construction costs, etc.), but with three different Manitoba demand curves. Also, each column represents the results of running the model 99 times, for different hydrological patterns, with a resulting average, maximum, minimum and standard deviation resulting from the hydrology. The two cases of a high discount rate and a low discount rate were applied and are shown separately in the first box and the second box.

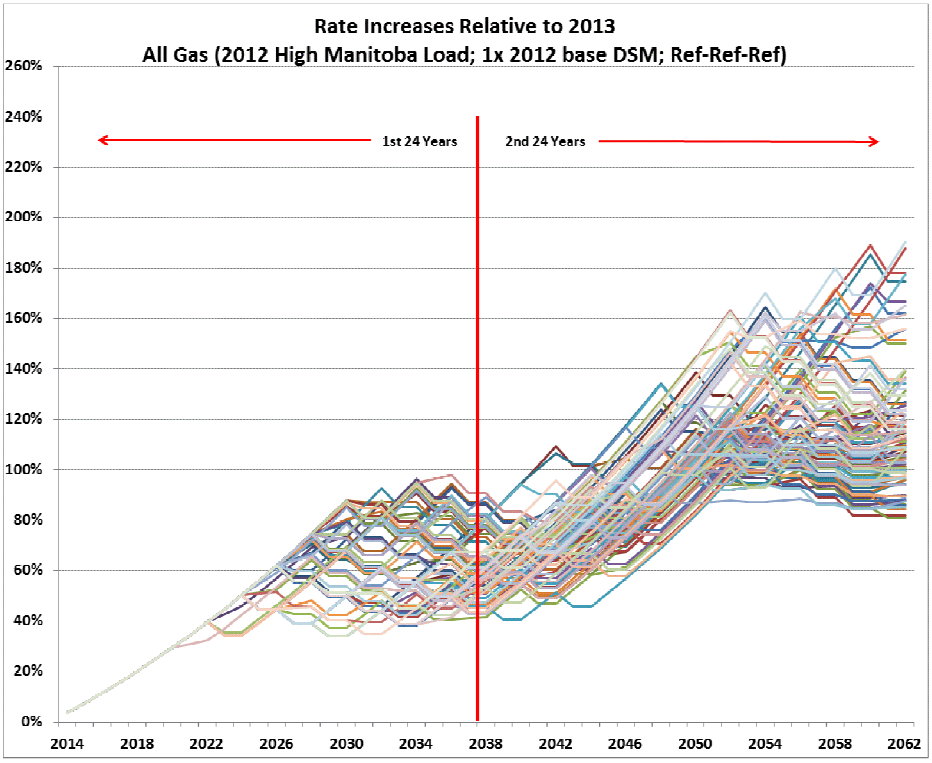
Some observations can be drawn:

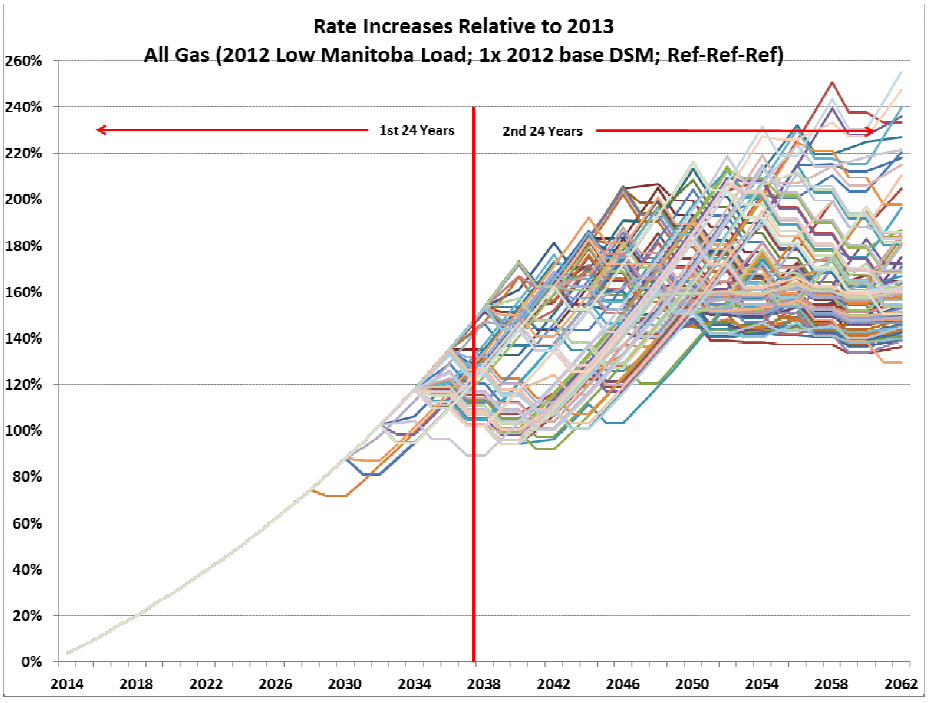
- Changing Manitoba demand does not actually affect the total cost to ratepayers over 48 years very much, if all other variables are kept constant; the difference in total cost to ratepayers between High and Low Manitoba demand futures is not more than about 2% in any of the cases
- On its face, this observation is surprising, because lower domestic demand means that more electricity should on average be exported, while higher domestic demand means that exports are decreased, and domestic ratepayers should be paying a larger portion of Manitoba Hydro's total costs.

To gain more insight into this situation, it is helpful to review the expected rates that Manitoba ratepayers will pay under the High and Low demand futures:

For the All Gas Plan (1), the rate paths are as follows:

Figure 12. Rate Increases Relative to 2013 (All Gas) (2)





Some differences become more apparent:

- When Manitoba demand is higher, the maximum rate increase is applied every year until the early to mid-2020s, but then rates for Manitoba ratepayers begin to diverge based on hydrology

- When Manitoba demand is lower, the maximum rate increase must be applied every year until the mid-2030s before rates begin to diverge based on hydrology
- This suggests that in this scenario, export prices are not high enough to satisfy Manitoba Hydro financial needs, even when export volumes are higher, and the burden is on ratepayers to do so
- In the higher demand scenario, charging Manitoba ratepayers the highest possible rate generates more revenue, which allows for faster retirement of debts, and eventually reduces the rate pressure of debt in later years
- In the lower demand scenario, charging Manitoba ratepayers the highest possible rate does not generate as much revenue because there is less total demand, so debt is not paid as quickly and continues to compound, which creates a heavier burden in later years that results in higher rates per unit of electricity
- When the total resulting revenues are discounted back to today, the result of the varying patterns is that the totals are very similar.

One of the inferences that can be made from these observations is that if export prices were assumed to be higher, then the benefits of lower domestic demand in terms of total ratepayer costs might be greater. Unfortunately, Manitoba Hydro did not provide SPLASH data for such alternative export prices combined with High and Low demand assumptions, so the inference cannot be thoroughly tested.

For the Preferred Development Plan (14), the differences in the rate patterns between the High and Low Manitoba demand assumptions are similar to what is depicted above for the All Gas Plan (1), and the inferences that can be drawn are the same. In short, if export prices are higher in the future, then reducing domestic demand is beneficial for Manitoba ratepayers, but if export prices are lower, then reducing domestic demand only raises cumulative rates in Manitoba, without providing ratepayers with much benefit.

4.3. Findings on Government Revenues

As might be expected, the differences between Resource Plans with respect to revenues for the Government of Manitoba are clear, and align with the construction of hydroelectric facilities.

Figure 13. Average Probability Weighted PV of Revenue to the Province of Manitoba

Average Probability Weighted PV of Revenue to the Province of Manitoba
High, Ref and Low Economics, Energy and Capital
(2015-2062)
($ in millions)

	Development Plan				
Revenue	**1**	**4**	**6**	**12**	**14**
NPV @ 6.00%					
Water Rentals	$1,702	$1,883	$1,879	$2,034	$2,091
Provincial Debt Guarantee	$2,614	$3,031	$3,075	$3,561	$3,783
Capital Taxes	$1,584	$1,874	$1,883	$2,229	$2,275

In the Preferred Development Plan (14), Conawapa is built and built soonest, and hence water rental fees are greater, more debt must be guaranteed, and capital taxes are highest.

The differences between Plans (14) and (12), where Conawapa is built a few years later, are very modest. Similarly, the differences between Plans (4) and (6), which both include Keeyask but not Conawapa, are very minor, but these totals are noticeably lower than the Conawapa-based Resource Plans.

These results are presented here for the lower discount rate, rather than the higher discount rate. This is appropriate because the time value of money for governments is very low. Arguably, for governments, the time value of money should be equal to its weighted average real cost of debt,[28] which would be substantially less than 6%. Using such a discount rate would accentuate further the differences between Resource Plans on this metric.

4.4. Findings on Export Orientation

Again as might be expected, the Preferred Development Plan (14), which includes the building of Conawapa earlier in time with the intention of signing long-term export contracts, includes the highest export revenues as a percentage of total Manitoba Hydro revenues. The chart below compares the revenue from exports as a percentage of total revenue, averaged over 48 years for a variety of hydrology patterns. Economic variables and construction costs are kept constant, but the group of variables including export prices and natural gas prices are tested at High, Reference and Low levels.

[28] Since both government expenditures and revenues typically rise with inflation, and government cost of capital is weighted between short, medium and long-term borrowings.

Figure 14. Average Export Revenue as a Percentage of Total Revenue (All Gas vs Preferred Development Plan)

Average Export Revenue as a Percentage of Total Revenue
All Gas and Preferred Development Plan
Reference Economics and Capital
(2015 - 2062)

	Development Plan	
Energy Scenario	**1**	**14**
Reference	9.5%	20.9%
High	11.9%	26.2%
Low	6.4%	14.3%

This outcome is relevant principally in two different ways:

- Resource Plans which have a higher reliance on export revenues are more sensitive to changes in export prices; this is borne out by reference to the model results if all variables except energy prices are kept constant: for example, average present value costs to ratepayers in Preferred Plan (14) are 10% lower if export prices are higher; whereas in All Gas Plan (1) there is little difference between the total ratepayer costs between scenarios with High and Low export prices[29]

- For government, higher exports mean that more of its revenue from Manitoba Hydro is actually coming from export jurisdictions, rather than ratepayers, which means that, *other things being equal*, the province as a whole should be receiving a net benefit.[30]

4.5. Findings on Hydrology

In any given year, or in any short-term period of a few years, hydrology affects Manitoba Hydro's financial performance more than any other variable tested.

The following table records the results of analysis done on a single year of the model, 2030:

[29] Note that since Manitoba Hydro's "Energy Prices" set of variables includes both export prices AND natural gas prices, for the All Gas Plan (1), higher prices means that exports are more valuable, but domestic production costs rise with fuel prices, with the two effects cancelling each other out to a great degree. The same is true in a lower prices environment, where lower export prices reduce export revenues, but lower gas prices reduce production costs. Since in the Preferred Development Plan (14) there is far less reliance on natural gas generation in Manitoba, the export price impact dominates and the difference between the high price and low price environment is very noticeable.

[30] Note that "other things being equal" is a crucial statement, since if pursuing higher export plans causes Manitoba competitiveness to suffer overall, then receiving a higher percentage of revenues from exports is not necessarily beneficial.

Figure 15. Average Difference Between Highest and Lowest Net Income (All Gas vs Preferred Development Plan)

Average Difference Between Highest and Lowest Net Income By Scenario, or by Year ($ in millions)	**Development Plan**	
	1	**14**
Within each scenario, all modelled years		
Difference, expressed as dollars ($)	$1,501	$1,972
Difference, expressed as % of highest (%)	171.8%	609.1%
Within a given year, all scenarios		
Difference, expressed as dollars ($)	$203	$780
Difference, expressed as % of highest (%)	27.3%	63.8%

What the model captures is that in the year 2030, the results for all of the model runs for both Resource Plans (1) and (14) were extracted. For each Resource Plan, the model was run 567 times (21 different hydrology patterns run separately for 27 different combinations of price variables). For each of the 27 combinations of variables, Manitoba Hydro's net income had 21 different results for the year 2030 based on the hydrology pattern used. The absolute difference between the highest and lowest net income result was recorded, both in dollar terms, and expressed as a percentage of the highest net income result. Then, the 27 different results from the 27 scenarios were averaged, to determine the average maximum impact of hydrology on the net income results of that year. For the All Gas Plan (1), the result was a potential difference in net income of $1,501 million (a swing from $550 million of net income to a loss of $950 million), and for the Preferred Development Plan (14) an even greater potential difference of $1,972 million (a swing from $275 million of net income to a loss of $1,690 million).

The second set of numbers represents holding the hydrology pattern for the year 2030 constant (the hydrology pattern was chosen so that water flow in the year 2030 and for several years before were approximately historically average), and comparing the difference in net income that results by testing all 27 different sets of variables and recording the maximum, minimum and resulting difference. For the All Gas Plan (1), this difference is only $203 million (a swing from $160 million of net income to a loss of $40 million), and for the Preferred Plan (14), the difference is $780 million (a swing from $475 million of net income to a loss of $305 million).

This analysis could be compared for other years and other plans, but the general result will be the same: hydrology drives Manitoba Hydro financial performance in any given year, much more profoundly than the expected range of any other variables will. However, it should be recalled that the historical record of hydrology demonstrates potentially massive swings on an annual basis, but tends towards the mean as longer and longer timeframes are examined.

One way of measuring this is to consider the standard deviation of the 100-year historical record of water flow in Manitoba. Over the entire 100 years, the standard deviation for annual flow is over 20, which means that in any given year, water flow can be expected to be in the range of +/- 20% of the historical average, two thirds of the time (however, fully one third of the time, it will be above 120% or below 80%). If water flow is averaged on a ten year basis, however, the standard deviation falls in half, with two thirds of ten-year averages falling between 110% and 90% of the average water flow. Over a longer period of time, the deviation shrinks further.

Put differently, the change in water flow on an annual basis can be dramatic. In an average year over the past 100 years, water flow was 18% higher or lower than the previous year. Eight times in the past century water flow has changed by +/- 40%! However, these gyrations just mask the fact that water flow tends to return to the mean.[31]

In terms of relevance to the choice of Resource Plans, it can be observed that:

- Hydrology is critical to short-term issues, such as the potential for financial distress, which will be addressed in the next section, but is less relevant to longer term issues such as the present value of ratepayer costs over a 48-year period or longer

- Though hydrology is less critical over longer terms, it does not mean that it is not relevant: even over a 35-year period the standard deviation of water flow is almost 5% of the historical average

- Resource plans heavy in hydroelectric investment, such as the Preferred Development Plan (14), are more sensitive to hydrology, and will therefore demonstrate greater variation in all financial results (including Manitoba ratepayer costs), especially in the short term but also over the longer term, other things being equal.

4.6. Findings on Financial Distress

It should be very apparent from the previous section on the impact of hydrology on Manitoba Hydro's financial results that there are scenarios where Manitoba Hydro may find itself in challenging circumstances. In average water flow years, it is apparent from the modeling that Manitoba Hydro's financial results will be adequate, across all 27 scenarios proposed by Manitoba Hydro, regardless of the choice of Resource Plan. "Adequate" in the sense of meeting its standards for debt:equity ratio in the longer term, keeping its Interest Coverage Ratio above 1.2,[32] and not increasing or decreasing rates by more than double the rate of inflation in any given year.

[31] Note that climate change and other long-term factors such as industrial development and water usage in watersheds can have long-term impacts on the mean water flow reaching Manitoba. This issue is not addressed here.
[32] Note that in some scenarios the ICR falls below 1.2 even in average water years, particularly between 2015 and 2025 when investment is greatest. However, this has already been signalled to the capital markets as an inevitable result of the intended long-term investment program, and there is no reason to believe that such a pattern would be cause for concern.

However, as the historical data makes clear, water flow need not be average, and in fact could at some point be well below average. In that case, Manitoba Hydro's financial results will not be within the planned ranges.

Many of the hydrology patterns applied to the model include "drought" scenarios at some point. If drought is defined as any year in which water flow is below the historical average, then an alarming number of droughts become readily apparent. If drought is defined as any five-year period when average water flow over five years is less than 95% of the historical average, then a more stringent test is being applied. In that case, there have been 37 such periods out of the 97 periods that can be counted in the last 101 years.[33] Very serious droughts with substantial financial impacts on Manitoba Hydro might be defined as five-year periods where average water flow is below 85% of average: there are 12 such periods out of the past 97. Most of these encompass periods centred in the 1930s and late 1980s. The last such five-year period was from 1988-89 to 1992-93.

Notably, the past 20 years have been extremely "wet" by historical standards, with only seven years below the historical average water flow, and a 20-year average of 110% of the historical water flow, one of the best such periods on record.[34]

There have historically been extended periods of serious drought:

- in the seven years from 1918-24 inclusive, every year was below average, and four of the seven years were below 85% of the average
- in the *eighteen* years between 1929-1946 inclusive, only three were above the historical average, and *nine* were 85% or less; this can be considered the "drought of the century" both in terms of length and severity, as it also includes the worst five-year period (from 1936-40, but that is almost equaled by the period 1987-91, when records are more accurate)
- in the sixteen years between 1980-95 inclusive, only three years were above average, and eight were 85% or less, including the severe period from 1987-91, the second-worst five years on record.

According to our model, it is absolutely clear that in the event of a severe, prolonged drought of the sort described here, Manitoba Hydro faces financial distress *regardless* of the Resource Plan selected, AND regardless of which of the 27 scenarios best describes the many variables that affect financial performance. In fact, distress is caused of such magnitude that the distinctions between the Resource Plans and scenarios are not particularly relevant.

The distress caused by a drought manifests itself in several ways:

[33] I.e., given data beginning from 1912 to 2012 inclusive, five-year periods would be counted from 1912-16, 1913-17, etc.
[34] In general, the "wet" decades have been the 50s, 60s, 70s and the 00s, while the 30s and 80s were both very "dry".

- The system's hydroelectric production falls dramatically, which reduces exports and export revenue, increases thermal production and therefore fuel costs, and increases imports and import costs
- The result is reduced operating income
- When depreciation and interest are deducted from operating income, net income will often be negative, which leads to interest coverage ratios below 1.0; in the worst years declines in operating results will be so severe that the interest coverage ratio is actually itself negative, which implies that cash flow before capital investments is insufficient to cover interest
- If net income is negative for a series of years, then retained earnings will steadily decline (possibly to the point of negative equity in the business), while at the same time all capital investments will have to be funded increasingly by debt, which compounds the interest burden for future years;
- Until the drought ends, and net income returns to positive territory, the company will continue to suffer deteriorating financial indicators from the compounding of debt increases.

There are two potential responses to this situation: raise rates, or borrow ever more to fund requirements. However, it should be made clear that solely raising rates to the level required to compensate for a drought is highly unlikely to be the practical solution. In some model runs across Resource Plans, rates would be required to rise by anywhere from 25% to 50% or more for a sustained period in order to maintain Manitoba Hydro's financial probity. Then, several years after the drought ends, rates could again fall steeply. This kind of response would play havoc with the business plans of Manitoba Hydro ratepayers, could undermine the competitiveness of many businesses, and would certainly change the competitive standing of the province with respect to other electricity jurisdictions.

A more realistic scenario is that rates would increase at something more than double the rate of inflation, but that the Government of Manitoba would also fund Manitoba Hydro's business with a combination of additional debt and possibly temporary relief from fees and taxes paid to government (water rental fees, capital taxes, and debt guarantee fees).

Speculating as to the magnitude of allowable rate increases in such circumstances is difficult: would rates be allowed to rise at triple inflation for a few years? Or, perhaps 10% per year? What balance would there be between a willingness to allow an "emergency" increase in the first year of a drought, and subsequent sustained increases when it is determined that drought is continuing unabated? If drought were to become the "new normal" over the course of a decade, would ratepayers/citizens be willing to see a Crown Corporation systematically raise rates during what would likely be seen as a time of hardship for many?[35] Since Manitoba has not faced this type of circumstance for more than 20 years, it is difficult to place a range on the potential response.

[35] For example, in a severe and prolonged drought, it can be expected that the agricultural community would suffer most acutely, creating a public and media awareness of drought, and the typical calls for government support.

A separate question would arise with respect to Manitoba Hydro's firm export contracts. Manitoba's electricity system is designed to ensure that these can be satisfied in all conditions where water flows are above the historic minimum. In "dry" years, however, meeting these firm commitments might require the burning of expensive fuel, making the contracts temporarily uneconomic. However, the contracts contain provisions ("adverse water") where delivery requirements can be suspended in the event of drought, so technically this situation could be avoided. However, actually suspending a firm export contract would be an extraordinary step to take,[36] and could change the standing of Manitoba Hydro as a potential commercial partner for years afterward.

4.6.1. Relative Susceptibility to Distress

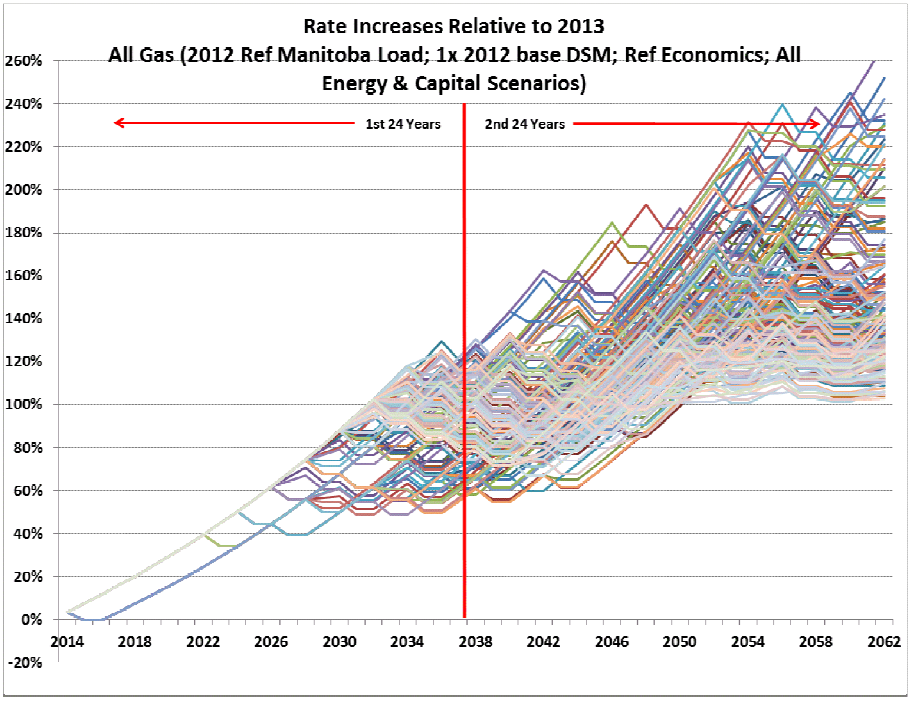
Despite the fact that the most severe situations of financial distress caused by drought overwhelm distinctions between Resource Plans, there are useful distinctions that can be made. These include sensitivity to hydrology, sensitivity to the timing of distress, and overall financial strength.

First, the point made in s. 4.5 above that some Resource Plans are more sensitive to hydrology is relevant. It is inescapable that the net income of Manitoba Hydro will be more sensitive to hydrology if Keeyask, Conawapa or both are built. A less severe drought may not affect Resource Plan 1 enough to drive Manitoba Hydro into distress. It should be noted that this sensitivity goes both ways: these Resource Plans will be exposed to higher highs and lower lows in net income and other financial indicators based on the future course of hydrology.

Second, timing is extremely relevant, and there are distinctions between the resource plans. In the first ten years of the model, all Resource Plans – including the All Gas Plan (1) – assume that rates increase at double the rate of inflation under all of the 27 scenarios and virtually all of the 21 hydrology patterns tested. For example, the following is the rate increase pattern for the All Gas Plan (1) in the 189 model runs that include reference economics (but varying hydrology, fuel costs, etc.).

[36] In 2003-04, when Manitoba suffered a significant one-year drought, all firm contracts were fulfilled and "adverse water" was not declared. However, it is notable that in the two following years after the drought, water flow levels shot up well above historical averages.

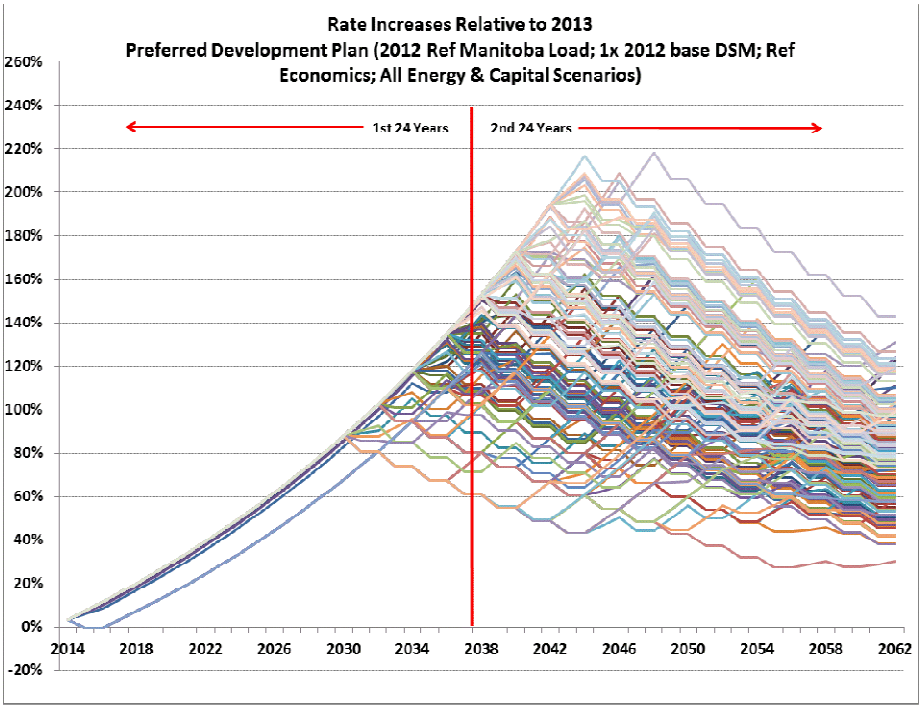
Figure 16. Rate Increases Relative to 2013 (All Gas) (3)



Until the late 2020s, very few model runs out of 189 include anything other than 3.8% annual rate increases. One implication is that Manitoba's competitive advantage with other jurisdictions may be deteriorating from its strong current position based on the steady increases. However, after that point, rate increase moderate in many scenarios and hydrology patterns, indicating that financial stress on the company is abating. To the extent that rates are flattening or declining, Manitoba's competitive rate flexibility could be improving. If a drought were to begin after that point, then the first response would be to return to 3.8% rate increases (which is exactly what many lines on the chart depict), and only then would other options have to be considered.

For the Preferred Development Plan (14), however, timing is different.

Figure 17. Rate Increases Relative to 2013 (Preferred Development Plan) (2)



Here, significant rate differentiation does not begin until the early to mid-2030s. Rates rise at a steady clip for the next 20 years, which must have some competitiveness consequences (depending on developments elsewhere, of course). This means that any financial challenge suffered during those two decades could only be addressed by extraordinary measures, whether in the form of higher rates or declining financial indicators coupled with government support. However, upon reaching the 2040s, rates begin a steady decline under virtually all scenarios, which indicates tremendous capacity to absorb shocks without unduly compromising the province's competitive position.

The third factor is the relative ability of Manitoba Hydro under each of the Resource Plans to absorb the potential deterioration to financial indicators that could be caused by drought. One possible measure of this factor is to compare the maximum negative net income that could occur in a drought year with the size of the interest payment that is due in that year. For example, in s. 4.5 above, the year 2030 was reviewed for Resource Plans (1) and (14) with respect to the potential impact of hydrology and scenario conditions. In the worst modeled case for that year (in the High Economics, High Energy Cost, High Capital Good Costs, with the hydrology of 1988), Resource Plan (1) had a net loss of $1,366 million and an interest coverage ratio of only 0.29x, while Resource Plan (14) had a net loss of $2,896 million but an interest coverage ratio of 0.33x. The size of the net loss caused by the drought in absolute terms was larger, but with respect to its impact on a financial indicator such as the interest coverage ratio it was actually relatively smaller, because of the larger balance sheet of the company in Resource Plan (14).

Such calculations change from year to year, Plan to Plan, and scenario to scenario, and cannot be calculated with confidence without meticulously testing the entire 3000+ model runs. However, a

general assumption can be made that the Resource Plans with larger balance sheets will be better able to absorb these situations over the full life of the model, other things being equal.

4.6.2. Magnitude of Distress

Assessing the relative "magnitude" of the distress to which each of the Resource Plans is susceptible is challenging because of its amorphous definition.

Is the magnitude the absolute size of a possible net loss in a single year? (Adjusted for inflation?) Is the magnitude the absolute size of the operating cash shortfall that might be suffered in the worst situations?[37] (Again, adjusted for inflation?) If government could compensate for temporary financial distress by exempting Manitoba Hydro from payments to government (water, debt guarantee and capital tax), is it the amount by which losses exceed these payments?

The purpose of attempting to calculate the magnitude of distress is to understand the problem in relation to the government, which is providing Manitoba Hydro with a debt guarantee, and which would be concerned if the company were no longer perceived by the credit rating agencies to be "financially self-supporting". The key test can be inferred from comments made by the credit rating agency Moody's in its report on the Province of Manitoba in July, 2013:[38]

> "This Crown Corporation's ability to meet its own financial obligations without recourse to provincial subsidies is a positive credit attribute for the province."

In a "normal" situation, Manitoba Hydro's guidelines target not only an interest coverage ratio of at least 1.2, but also coverage of typical capital spending requirements from internally generated funds. If the company were not able to meet this objective during a one or two-year drought, it would be unlikely that credit rating agencies would reassess their position on the ability of Manitoba Hydro to be self-sustaining.[39] However, if drought conditions continued, and rates were not allowed to rise sufficiently to meet these interest and capital targets, then the shortfall in meeting them would become a focus for attention.

In this case, *longevity* of financial distress caused by drought would be the indicator that the problem had ANY magnitude. Only secondarily, the size of the cash shortfall in successive years would then be an indication of the magnitude of the problem.

Returning to the example mentioned above relating to the model year 2030, if the losses described occurred in only one year, because of a sudden drought, but then in subsequent years financial indicators turned around, then there would be no magnitude to the problem. However, if those net losses were part of a repeating pattern because of a deep and long drought, and there was an

[37] I.e., the amount by which a potential annual net loss exceeded 1.2 times debt interest.
[38] Moody's Investor Service, *Province of Manitoba Credit Analysis*, July 2013, p. 3.
[39] Manitoba suffered a short, sharp drought in 2003-4. The DBRS Credit Report on the Province of Manitoba on June 22, 2004 noted that the province suffered "an unexpected, and likely non-recurring, loss of $359 million at The Manitoba Hydro-Electric Board ("Manitoba Hydro") as a result of unexpectedly low water levels." No further impact occurred, as water flow returned to average and subsequently above average levels in the following years.

unwillingness to drastically raise rates to compensate for the need for revenues, then it would be absolute size of the net loss that would indicate the magnitude of the problem. In short, for Development Plan (1), where the net loss was $1,366 million, the magnitude would be less than for Development Plan (14), where it was $2,896 million.

Moreover, in provincial terms, because of the debt guarantee provided by the Province of Manitoba to Manitoba Hydro, these cash shortfalls would be translated into the form of supported debt. Since these situations occurred in the High economics environment, where the cost of Manitoba Hydro debt is assumed to be nearly 9%, then the magnitude of debt that would be lacking support would be $15 billion in the case of All Gas Plan (1), and over $30 billion in Preferred Plan (14).

It should be noted that hydrology year 1988 was a singularly severe drought year, and there was some recovery in each of these model runs subsequently, so shortfalls of that magnitude would not be repeated. However, the assumption about financial capacity being related to size of balance sheet is reversed with respect to magnitude of exposure to financial distress. In the event of a sustained, severe drought, Resource Plans with a larger balance sheet due to investment in hydroelectric facilities will have a greater magnitude of exposure, commensurate with that balance sheet and amount of debt. Once a drought ends, the sensitivity to hydrology will again become a positive, and quickly return the magnitude of exposure to zero.

In order to test the magnitude of financial distress more carefully, several assumed droughts in the 2020s and 2030s were examined. Sustained, deep drought hydrology patterns were used, with the same pattern used for each of the decades. The Preferred Development Plan (14) was particularly susceptible to drought in the earlier period, facing shortfalls of over $1,000 million per year in a number of years (that represents rate increases of 35% to 50%, depending on the year). However, when the same drought experience is faced in the mid-2030s, no financial distress is experienced. At that point, debt had been declining at Manitoba Hydro for several years, and rates were actually in the midst of falling when the drought occurred. Reversing the rate direction in that situation was sufficient to address the challenge. For All Gas Plan (1), circumstances are reversed: it was able to weather the storm in the 2020s with two years of poor results, but in the example of the 1930s, a sustained $1,000 million shortfall resulted unless rates were hiked systematically.

4.6.3. Cost Overruns

While drought is the most likely and expected source of financial challenges for Manitoba Hydro in considering its Resource Plans, it is not the only possibility. As was described in s. 3.3.5 above, there have been instances around the world where large construction projects have gone horribly wrong, resulting in substantial hardship for stakeholders.

Two observations seem pertinent: first, given that a construction cost overrun would be manifested in Manitoba Hydro's case as an increase in debt, it is only the debt interest amount that would present an immediate challenge. Second, given that it is only changes in revenue of a size potentially caused by hydrology that actually undermine Manitoba Hydro's performance, an overrun would have to be truly massive in proportion to be significant.

For example, a cost overrun of $1,000 million under the High economics scenario would generate a year two debt interest of just under $100 million. In the case of financial distress caused by drought, swings in cash flow of ten times that size were under examined. An unnecessary cash cost of $100 million per year would not be welcomed, but would not undermine the performance of the company (that would even be true at two or three times the size).

This is not to say, however, than an extraordinary construction cost overrun would not be important: such events would change the full 48-year cost to Ratepayers, as follows:

Figure 18. PV of Domestic Revenue (Average Impact of Additional Capital Expenditures on Conawapa)

PV of Domestic Revenue
Average Impact of Additional Capital Expenditures on Conawapa
Preferred Development Plan
Additional capital outlay in 2025 (real 2014 $)
NPV @ 6.00%
($ in millions)

	Additional Capital Cost		
	$0	$1,000	$2,000
PV of domestic revenue	$44,230	$45,016	$45,839
Increase relative to nil increase	0.0%	1.8%	3.6%

While the sensitivity to cost overrun may not be sufficient to undermine the company, it would greatly damage the value proposition of the Resource Plan in question.

5. Specific Issues of Interest

5.1. Cost of Capital and Discount Rate

In Appendix 9.3 of the Business Case, Manitoba Hydro provides details concerning the construction of the High, Reference and Low sets of variables included in the 27 scenarios used in the analysis of the Resource Plans. MPA accepted and utilized these scenarios as preparation for this Report to the PUB, however some observations can be made about the cost of capital which the PUB may find useful. In addition, MPA did not utilize the costs of capital constructed by Manitoba Hydro as discount rates in our financial model, and hence some additional commentary appears appropriate on this issue.

5.1.1. Cost of Capital

The following is a summary of the various components of Weighted Average Cost of Capital (WACC) utilized by Manitoba Hydro.

Figure 19. Weighted Average Cost of Capital (Manitoba Hydro)

Weighted Average Cost of Capital (WACC)

		Nominal			Inflation			Real		
	Ratio	High	Ref	Low	High	Ref	Low	High	Ref	Low
Debt	75%	8.95%	6.30%	3.65%	3.00%	1.90%	1.00%	5.78%	4.32%	2.62%
Equity	25%	11.95%	9.30%	6.65%	3.00%	1.90%	1.00%	8.69%	7.26%	5.59%
WACC	100%	9.70%	7.05%	4.40%				6.50%	5.05%	3.37%

The foundation stone for all calculations is the reference nominal cost of long-term debt (6.30%), based on the consensus forward forecast for long Canada bonds, plus adjustments for the actual cost of debt to Manitoba Hydro. This figure is used to calculate the "real" cost of debt, discounting it for the reference inflation rate (1.90%), which is again based on a consensus forward forecast. At the same time, the cost of equity is assumed to be a fixed amount of 3.00% higher than the cost of debt.

On any given day, a slightly different calculation could be used to calculate the real cost of debt that Manitoba Hydro would be expected to face:

Cost of Canada bond at whatever length of term is desired (typically 10 or 30 years)

\+ Province of Manitoba Spread (over the past 20 years ranging from 0.2% to 1.0%+)

\+ Debt Guarantee Fee (currently 1%, but subject to unilateral change by the Province)

For example, on January 15, 2014, the benchmark Canada Long-Bond traded at 3.12%, and the Manitoba spread was approximately 0.85%. Adding the 1% Debt Guarantee Fee results in a Manitoba

Hydro cost of 4.97%. In comparison, the reference nominal debt rate used in the Business Case is not insignificantly higher.

However, the Canada Long-Bond rate may be implied from the nominal reference cost of debt used by Manitoba Hydro in the Business Case:

Figure 20. Implied Canada Long-Bond (1)

Implied Canada Long-Bond		
Reference nominal debt	6.30%	6.30%
less:		
Provincial debt guarantee fee	1.00%	1.00%
Province of Manitoba spread	0.40%	0.60%
Implied Canada Long-Bond	4.90%	4.70%

By this calculation, the reference nominal debt rate assumes a Canada Long-Bond in the range of 4.70% to 4.90%. Comparison to the history of the Canada Long-Bond, which is readily available on the Bank of Canada website, confirms that a rate in this range was indeed common in the 1920s, early 1930s, 1950s and early 1960s, and again in the first half of the last decade, before the financial crisis in the latter half of that decade.

Similar derivations for the high and low debt rates used in the Business Case appear as follows:

Figure 21. Implied Canada Long-Bond (2)

Implied Canada Long-Bond	**High**	**Ref**	**Low**
Cost of nominal debt	8.95%	6.30%	3.65%
less:			
Provincial debt guarantee fee	1.00%	1.00%	1.00%
Province of Manitoba spread	0.70%	0.50%	0.30%
Implied Canada Long-Bond	7.25%	4.80%	2.35%

Again, reference to the historical record shows that a Canada Long-Bond in the range of 7% has occurred, but only for relatively brief periods in the early 1970s and early 1990s, when the world was entering and then exiting a period of very high interest rates that lasted from approximately 1975 to 1995 (Manitoba Hydro did not include a “very high” rate that would attempt to capture such an economic environment, where the Canada Long-Bond was above 9.00% for thirteen consecutive years). Moreover, a Canada Long-Bond in the low 2.00% range has occurred even more rarely, having occurred

only in the last two years. Even in the 1930s and the 1950s, two periods which are historically recognized for lower interest rates, the Canada Long-Bond breached the 3.00% mark only rarely.

It should be recalled that the purpose of the scenarios is to construct sets of variables that are to be used in long-term models, and used *throughout the duration* of the model. In the case of Manitoba Hydro's "real" economic model, that term is 78 years, and in the case of Manitoba Hydro's nominal dollar model (and MPA's financial model), that term is 48 years. The scenarios should be understood as "averages" that would apply to the whole period in question.

Manitoba Hydro assigned probabilities of 35% for high, 50% for reference, and 15% for low with respect to the cost of debt. By reference to the historical record, there does appear to be strong support for the reference scenario, and some support for the high scenario, but little if any support for the low scenario as it is constructed, at least with respect to the cost of debt.

A similar review could be undertaken for the inflation rate options, set by Manitoba Hydro at 3.00%, 1.90% and 1.00%. Again, reference to available resources suggests that there is ample historical justification for the higher two rates (and even for a "very high" rate for long periods of the last century), but very limited justification for a 1.00% inflation rate as a potential average rate for a fifty-year or longer period.

Finally, Manitoba Hydro constructs its cost of equity by the straight addition of 3.00% to the selected cost of debt. To the extent that this cost of debt already includes the Provincial Debt Guarantee Fee and the Province of Manitoba spread, an equivalent calculation indicates that the notional return on equity that is assumed in the cost of capital is approximately 4.50% above the Canada Long-Bond at any given time.

On this issue, reference can be made to a study undertaken by the Ontario Energy Board in 2009,[40] which included analysis by five economists/experts on equity rates for regulated utilities across North America, with reference to historical market data, regulatory practice in a number of jurisdictions, and a variety of recognized techniques for deriving appropriate equity rates. The conclusion of a lengthy review process (and the availability online as part of that process of a full literature review of equity costs of capital), was that "low risk" transmission and distribution utilities were considered to have an equity cost of capital approximately 5.00% higher than Canada Long-Bonds.

Given Manitoba Hydro's high degree of exposure to hydrology risk, its financial exposure to market export prices, and the ambitious program of construction included in the Preferred Development Plan, legitimate issues can be raised with respect to the adoption of an equity rate of return that is even lower than a "low risk" premium of 5.00%.

[40] *Report of the Board on the Cost of Capital for Ontario's Regulated Utilities*, Ontario Energy Board, EB-2009-0084.

5.1.2. Discount Rate

Manitoba Hydro chose to utilize its WACC as the discount rate in all of its present value calculations. The justification is presented as follows in s. 9.2.3 of the Business Case:

> The starting point for development of a discount rate is a company's overall cost of financing. As a discount rate is used to guide investment decisions based on uncertainty, a risk premium may be identified to arrive at a discount rate which makes the investor indifferent between cash amounts received at different points in time.

Manitoba Hydro used the reference WACC as its discount rate (either nominal of 7.05% or real of 5.05%) throughout its analysis, except with respect to updated 2013 figures, when the reference real WACC was increased to 5.40% because of increases in some of the underlying consensus forecasts.

Several observations can be offered:

- WACC is the appropriate concept to consider the present value of cash streams in the future for the purposes of an investor considering an investment decision, however, Manitoba Ratepayers are not investors
- While it is true that Manitoba Hydro will source the capital required for its chosen Resource Plan from a combination of debt and retained earnings, and while the retained earnings are at least partially derived from ratepayer revenues, ratepayers can in no sense be understood to be making a voluntary investment decision, particularly given the monopoly nature of the utility service that is being offered, and the decision-making authority that rests in the hands of the government
- Calculation of the WACC, and its use in models predicting Manitoba Hydro's financial results – and hence electricity rates that ratepayers will face – is entirely appropriate given the likely use of the formula in the setting of rates over time by the PUB, however, this does not automatically qualify the WACC for use as the discount rate relevant to all parties considering the Business Case
- From the perspective of ratepayers, or any other stakeholder considering the Business Case, the primary value of the discount rate is in providing a means to compare varying cash streams over time from the perspective of today, in essence, a "time value of money" which is appropriate to that stakeholder
- The primary stakeholders in the Business Case identified in this Report are ratepayers and the Government of Manitoba; notably, neither of these parties is directly and voluntarily investing equity in the project
- It can be argued that governments have very low "time values" of money, given the permanence of the institution, and typically its access to the lowest cost of funds; ratepayers,

however, are a heterogeneous group for whom generalizations are very difficult, and for whom the adoption of a single, blended time value of money may not be appropriate.

While there is an existing literature with respect to the choice of appropriate discount rates to represent ratepayers, we have not pursued this issue further. For the purposes of this report the use of two discount rates was adopted, both nominal, at 6.00% and 10.00%. These rates bracket the rate adopted by Manitoba Hydro, and offer the possible consideration of the various resource plans from more than one perspective.

5.2. Exports

As has been discussed elsewhere in this report, Manitoba Hydro has generated a substantial portion of historical revenues from exports. Of these revenues, a significant portion is directly tied to short-term market prices, while another portion is the result of longer-term firm contracts. These contracts, however, are not specifically tied to any asset, but instead are based on the output of the Manitoba electricity system as a whole. As a result, their length, pricing schedule, and terms and conditions all reflect the underlying export electricity markets and counterparties with which Manitoba Hydro interacts.

These contracts can be contrasted with Manitoba Hydro's own contracts with the wind farms that have been constructed in the province. In those cases, Manitoba Hydro has purchased all of the output of the wind farms for their full expected life, at rates that were negotiated between the parties based on the cost of construction and operation of the wind farm plus an amount meant to represent a return on investment for the wind farm owners. These are classic "infrastructure project" contracts which effectively apportion and minimize the risks and costs of a project for both parties.

Manitoba Hydro has negotiated a number of agreements with parties as part of the development of the Preferred Development Plan, as described in the Business Case. The electricity resources that will be built as part of the Preferred Development Plan are hydroelectric facilities with an expected life of over 100 years. The contracts negotiated, however, have terms which last a fraction of that time. In addition, the price of the contracts is based on prevailing market conditions, and not in any way related to the cost of the electricity resources being built. They are in fact system energy arrangements, similar to the system energy arrangements that Manitoba Hydro has signed in the past. As such, their chief usefulness is in providing Manitoba Hydro with a guaranteed buyer for a portion of the system's expected surplus power, and a firm price for a period of time, which provides additional predictability to cash flows.

Considered more broadly, Manitoba is simply a price taker in the MISO market, whether it is taking prices in short-term markets, or in a longer-term market for bilateral arrangements with specific counterparties. The value of the longer-term contracts negotiated at any time are likely, as Potomac Energy, another independent expert consultant to the PUB, has argued in their report,[41] to be based on the cost of new entry into the MISO market (or in other words, the cost of constructing new supply resources in the MISO market at the time a contract is negotiated). As a result, the longer-term firm

[41] Please see Report to the PUB provided by Potomac Energy on January 15, 2014.

contracts are not mitigating market risk or exposure for Manitoba Hydro, but merely apportioning the market risk accepted in pursuing the Preferred Development Plan.

In this respect, Manitoba Hydro is acting as a "merchant" investor, taking substantial market risk based on expectations, or bets, about the future. While "probabilities" have been placed on different potential futures through the scenario modeling process, fundamental market risks are necessarily imbedded in some Resource Plans to a far greater extent than in others. Prices will either turn out to be high, and ratepayers will benefit, or they will turn out to be low, and ratepayers will have to shoulder more of the burden of Manitoba Hydro costs. Either way, ratepayers can have no certainty in advance, and no choice in the matter.

Given the legislative mandate of Manitoba Hydro to reinvest all earnings, and keep rates as low as possible, it is clearly not a merchant investor. However, the tacit acceptance of risks that would be normally within the scope of a merchant investor suggests the issue deserves scrutiny.

5.3. Impacts on the Government of Manitoba

In s. 4.6, the potential for and magnitude of Manitoba Hydro financial distress was discussed. It was suggested that depending on the choice of resource plan, the timing, and the depth of a drought event, it is possible that for a period of time Manitoba Hydro could suffer a sustained period of financial distress which could result in the view that the company is no longer fully self-supporting. Many factors would play into this conclusion, including the longevity of the distress, and the severity. However, in certain scenarios, if a severe drought were to occur in the 2020s, there is the possibility that the approximate equivalent of $10 billion or more of Manitoba Hydro debt could be viewed as not "financially supported" by rates.

In practice, what this would mean is that the Government of Manitoba would have to lend additional sums to Manitoba Hydro in order for the company to meet its cash requirements (both to pay debt interest and refinance expiring principal, and to finance the purchase of necessary capital goods). The ability of the government to provide such funding is not called into question, but rather it is the potential impact on the view of the Province by credit rating agencies and other capital markets actors that is in question.

5.3.1. Manitoba Financial Profile

Currently, Manitoba is positively viewed by credit rating agencies, and maintains a high rating (Aa1 from Moody's, AA from Standard and Poors and A (high) from DBRS). Recent credit reports, which have been provided as part of the NFAT process, have highlighted the relatively strong and stable economic performance of the province in the years since the financial crisis of the last decade, the varied sources of strength in the province's economy, its population growth through immigration, and the stable fiscal and financial management of the government.

Projecting forward ten, twenty or thirty years to a possible financial distress episode at Manitoba Hydro on the basis of current estimates is a tenuous exercise at best, both because of the time involved, and

because of the vagaries of the credit rating world. In the past twenty years, Moody's has upgraded Manitoba's credit rating three times, while Standard and Poors did so only once in the last fifteen years, and DBRS has not changed its rating for the past 10 years. DBRS rates Manitoba equal to Quebec, but less than Ontario, while Standard and Poors rates Manitoba one notch above Ontario and two notches above Quebec. Managing the perceptions of the capital markets is an art, not a science.

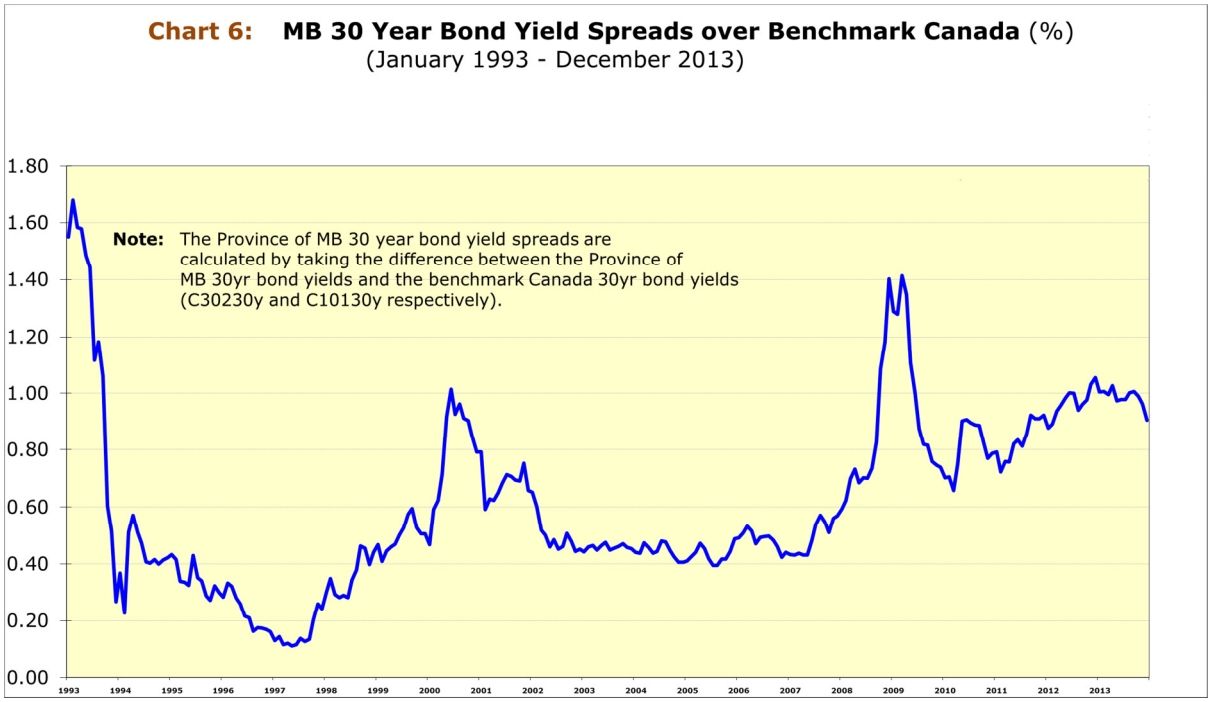
Currently, Manitoba Hydro's debt is considered to be self-supporting, and hence is not included as part of Manitoba's net tax-supported debt. Across the credit rating agencies, Manitoba's net tax-supported debt is calculated to be between $15 and $20 billion, depending on the agency in question. Debt to GDP ratio is calculated as approximately 30% to 35% of GDP. According to a calculation by DBRS, Manitoba's Debt to GDP ratio is similar to that of Nova Scotia and New Brunswick (with whom it shares an A (high) rating), but less than Ontario's 41% (but Ontario is rated higher at AA (low)), and much lower than Quebec at 60% (though the province has the same rating as Manitoba).[42]

Manitoba's GDP growth has been averaging approximately 2% per year in the last five years (while many other jurisdictions suffered severely), yet net tax-supported debt has grown substantially faster. The province is widely expected to pursue a substantial infrastructure program that could dramatically increase debt even further. If, for example, the province's economy continues to grow at 2% per year, then GDP will reach $70 billion in ten years (if the province were to reach a 3% average growth rate, then GDP would grow to $77 billion). However, if tax-supported debt were to grow by $10 billion, then the debt to GDP ratio would rise to approximately 42%, which is the reported level of Ontario today.

In this discussion of credit rating and credit rating agency overviews, it is important to consider the practical impact of these positions. The metric by which provincial credit is judged on a daily basis is the credit spread between a province's bonds and Government of Canada bonds. The following chart, provided to MPA by Manitoba Hydro, depicts the progress of the credit spread over the past 20 years.

[42] Please see the DBRS 2013 Provincial Fact Sheet.

Figure 22. Manitoba 30 Year Bond Yield Spreads Over Benchmark Canada (%)



It is immediately notable that the pattern of the credit spread between Manitoba bonds and Government of Canada bonds does not correspond to rating agency views. In fact, what is more noticeable is major economic trends and events, such as the financial crisis in 2008, the terrorist attack on the United States in 2001, and the Asian credit crisis in 1998. Along the way, the constant gyrations of the credit spread do not seem to be related to the overall stability in credit rating reviews that Manitoba has enjoyed. Finally, both Moody's and DBRS increased Manitoba's credit rating in 2003, after the spread had already declined, and with no apparent further affect once their new positions were announced.

It is quite possible that Manitoba's capital markets position could deteriorate over the next twenty years, but it is also possible that it could improve, through prudent fiscal management, balanced budgets and continued focus on economic development and prosperity. Despite all of that, the credit spread could still widen, or contract, with little to no relation to any local accomplishment or failing.

5.3.2. Context for Potential Manitoba Hydro Distress

As discussed, Manitoba Hydro, particularly in the context of the Preferred Development Plan, is financially sensitive to hydrology. If there were to be a prolonged and severe drought, particularly in the 2020s when the company would be most susceptible to financial distress, then a substantial portion of the company's debt could cease to be considered "financially self-supporting".

There are several issues which should be taken into account with respect to the impact of such a situation on the Province of Manitoba:

- All droughts, even the most severe, eventually end, and with the end of the drought would be the return of revenues and profits for Manitoba Hydro; all of the credit rating agencies and capital markets will understand this reality
- Concern is likely to mount progressively through a drought, with impact on the Province only becoming an issue over time (a one-year event, such as occurred in 2003-04, would simply not register)
- If a severe drought was indeed occurring, it would be affecting far more than just Manitoba Hydro; in fact, Manitoba Hydro would be one of the last focuses of attention, as the agriculture sector, forestry, parks and wildlife and many others affected by drought would gain attention first
- In a situation of severe natural disaster, governments are expected to step in with assistance, which would include not only the Manitoba government but also the Government of Canada (though not necessarily on an issue such as electricity prices)
- Given that the watersheds serving Manitoba Hydro's facilities are spread across several provinces and states, a drought of this magnitude would not be localized, adding to the overall attention to it.

In such a context, Manitoba Hydro would be faced with a drought and deteriorating financial indicators, and need to advocate for rate increases to improve its finances. While only a small fraction of Manitoba's economy is dependent on agriculture, there are still many people in the agriculture sector who would be affected by drought, and who would be resistant to increases in electricity prices. Moreover, insofar as electricity rates will have been rising steadily at 3.8% per year for the next ten years, rate fatigue may well have set in.

If no or only low rate increases are implemented, and a shortfall in cash requirements continues, then several practical consequences will ensue:

- Manitoba Hydro will suffer repeated years of losses, which will reduce equity over time, leading to a deteriorating debt:equity ratio
- For the Province of Manitoba, Manitoba Hydro's earnings appear in the budget as revenues, and losses as expenses, so a drought would have an immediate bottom line impact on the deficit (however, since no dividends are ever paid to the government, credit rating agencies and other sophisticated analysts already deduct Manitoba Hydro earnings from the "adjusted" versions of Manitoba's annual budgets)

- Water rental payments would drop significantly in a drought, which has a real cash impact on provincial budgets, but substantially smaller than the potential impact of losses, as described above

- The provincial government would need to decide what form(s) of relief it would provide to Manitoba Hydro in such a situation, beyond allowing extraordinary rate increases at some level; the choice would likely be between some combination of lending additional funds, or exempting Manitoba Hydro from certain payments

- If the province exempted Manitoba Hydro from any payments, then that step would have immediate budgetary consequences, whereas simply extending additional credit would be a capital account transaction

- An additional consideration would be that lending to Manitoba Hydro would simply be the extension of credit support to ratepayers, not an actual cash transfer between taxpayers and ratepayers, as would be the case if Manitoba Hydro were provided with any kind of tax holiday or exemption; in the case of additional lending, ratepayers would ultimately be responsible for the full amount over time, including underlying interest and the debt guarantee fee.

As with so many issues in the capital markets, perceptions would be crucially important. If prior to the onset of a drought, Manitoba continues to enjoy a strong competitive position with respect to electricity rates elsewhere, then financial distress from an ultimately time-limited drought might simply be perceived as a temporary phenomenon that would eventually resolve itself through steadily increasing rates, and an eventual return of water flow. In that scenario, little to no impact would be expected on the province. On the other hand, if prior to the drought Manitoba Hydro's competitive position had already deteriorated, then the potential to reassign multiple billions of dollars of debt from Manitoba Hydro to the Province could be viewed as a more likely course, with all of its attendant possible impacts.

6. Costs, Risks and Benefits

6.1. Ratepayers

As identified in Chapter 2, the primary interest for Manitoba ratepayers is to pay the lowest risk-adjusted cost for their electricity over time.

In some sense, both the cost and the benefit for ratepayers is the same thing: the monthly bill for the electricity they consume. Through financial modeling, the five Resource Plans were compared across all 27 scenarios and 21 hydrology patterns. The rank ordering of the Resource Plans very much depends on whether a scenario is isolated, or whether several scenarios are allotted probability weights.

Risk is the principal differentiator between the Resource Plans. Choice of a Resource Plan is in large measure a choice about the risks that Manitoba Hydro will be financially sensitive to, and which will be passed on to Ratepayers in the form of rates.

Table 8. Risk and Impacts Across Development Plans

Risk	Impacts
Demand	• Smaller, shorter construction-time resources can be more accurately targeted to expected domestic demand, favouring Plan 1 • All Plans can suffer if domestic demand stalls or declines after resources are built, though larger individual facilities in Plans 12 and 14 face such stranded asset risk to a greater degree; mitigated by the fact that "demand" need not be domestic demand • The impact in the event of lower demand depends on the relationship between export prices and domestic rates at the time the expected demand does not materialize; if prices have to rise steadily for a longer period, as in Plans 12 and 14, then more of this competitive advantage may be lost
Hydrology	• There is a clear difference in sensitivity to hydrology as between the Plans, with Plans 12 and 14 being most affected by water flows • The volatility of water flows translates directly into volatility of cash flows, which can be positive as well as negative
Export/Import Prices (& Fuel Prices)	• There is a clear difference in sensitivity to export markets and market prices between the Plans, with Plans 12 and 14 being most sensitive, but again, sensitivity can be both positive and negative • The reduced sensitivity in Plan 1 to changes in this set of variables may have much to do with the fact that fuel prices and export prices are tied together
Construction Costs	• The absolute magnitude and complexity of building a project like Conawapa increases risks
Interest Rate	• All Plans are dramatically affected by interest rates and inflation assumptions
Technology	• Plans with longer – lived assets forego the possibility of adapting to improvements in technology

It should be recalled, however, that the overall "risk-adjusted" impact of the choice of Resource Plans will only be marginal over the very long term, when considered from a present value perspective. The existing system will continue to be the backbone of electricity supply for many years to come, and the Resource Plans do not change the fundamental hydroelectric nature of the Manitoba electricity system.

The second critical aspect for Ratepayers is the treatment of time: while this is not a risk in the normal sense of the word, there is an apparent difference in intergenerational treatment between the Resource Plans. The rate paths described in s. 4.2.1 make clear that a strong opinion on the time value of money can have an almost deterministic effect on the choice of Plans from a Ratepayer perspective.

6.2. Government of Manitoba

The Government of Manitoba has a clearer set of costs, benefits and risks to consider.

The Preferred Development Plan and Plan 12 both include Keeyask and Conawapa: these Resource Plans would require the largest balance sheet, most guaranteed debt at risk, the longest construction times, and the longest sustained period of initial rate increases. On the other hand, they will provide the most government revenues, generate the most significant construction employment and attendant economic development, and hold the promise of maintaining or improving the province's electricity competitiveness for decades into the future.

From the perspective of the government, the relatively minor distinctions that result based on the outcome of the twenty-seven scenarios is largely irrelevant. The Government's focus is not on having the lowest possible costs, only a competitive cost. While the Preferred Development Plan is virtually guaranteed to require a doubling of electricity rates over the next 20 years, it holds the promise of actual rate declines in the following period and beyond.

The critical issue for the government is the ever-present threat of drought. While there has not been a severe and prolonged drought in Manitoba for twenty-five years, there will inevitably be another one. Timing will matter with respect to the degree of sensitivity to financial stress, and the choice of Resource Plan will determine the seriousness of the impact. The pattern is nearly identical to rates for consumers: The Preferred Development Plan has a heightened sensitivity to drought in the first twenty years, but less sensitivity to drought in the subsequent period.[43]

[43] For consideration of broader economic development issues, please see the Report to the PUB of Typlan Management and Planning. For review of environmental issues, please see the Report to the PUB of MNP. While these issues are of obvious concern to the Government of Manitoba, they are outside the scope of this report.

7. Conclusions

Analysis of the available data and construction of a financial model capable of incorporating hydrology has allowed for the illumination of a number of patterns, and a variety of observations that will, it is hoped, assist the PUB in making its recommendations to government on the NFAT Review of the Manitoba Hydro Preferred Development Plan.

Key observations have included:

- The ability of Manitoba Hydro to meet its financial targets over the next ten years without increasing rates beyond two times the rate of inflation – under all Resource Plans – is entirely dependent on the continued absence of a significant drought
- Different Resource Plans extend that period of fragility, including the Preferred Development Plan, which should not be expected to enter a time of more financial capacity for twenty years, unless rates are allowed to rise at more than double the rate of inflation for an extended period of time
- In the face of a sustained, severe drought, the choice of Resource Plan is irrelevant to the occurrence of distress, as the financial consequences of such a drought would overwhelm the differences between Resource Plans
- Choice of Resource Plan does affect the occurrence of financial distress due to drought in milder drought cases, and it also affects the magnitude of the problem that would be faced by government in the event of a drought of any kind
- The total, probability-adjusted present value of ratepayer costs over 48 years across all five Resource Plans is likely too narrowly distributed to allow for definitive selection of the "lowest cost" choice. These outcomes are essentially within the margin of error of the many calculations, estimates and assumptions that were required to construct the model
- The consistent patterns of sensitivity of specific Resource Plans to certain variables indicates that model analysis can provide a guide to identifying the concerns that should be part of any decision-making process
- An extremely important inter-generational decision is embedded in the choice of Resource Plan, as costs to Ratepayers will be distributed very differently over time.

Bearing these and other observations in mind, we would suggest the following recommendations:

d) Plans 4 and 6, which were largely indistinguishable from each other, resulted in costs to ratepayers that appear to be lower than other Resource Plans in many scenarios, if only marginally; this suggests that proceeding with Keeyask may be a prudent step to take at this time, but a more thorough review of the proposal to build Conawapa as part of the Preferred Development Plan should be undertaken closer to its final commitment date

e) Given the expected fragility of Manitoba Hydro during the first ten years of any Resource Plan, and beyond that in others, the Government of Manitoba may wish to calculate and reserve some of the funds it generates (e.g., through permits, approvals, income taxes, etc., related to the construction projects) to act as an initial financial buffer for the government in the event of drought and the need for financial assistance to Manitoba Hydro

f) Given the inevitability of a drought at some point in the future, and the expected financial impact that such a drought would have on Manitoba Hydro, particularly in the near term, consideration should be given to the development of an explicit policy on the future course of customer rates in such a situation; this policy could then be shared with credit rating agencies and others to address the potential concern that they may have that in the event of a drought some fraction of Manitoba Hydro debt might be financially unsupported.

Appendix A Biographies of MPA Contributors

Pelino Colaiacovo

Pelino is a Managing Director at MPA. In this role he is responsible for origination and transaction execution, financial advisory and capital raising services. Since joining MPA Pelino has focused on advising clients in the energy, utilities, infrastructure and public sectors.

Utility clients have included Hydro One, BC Hydro, Enwin Utilities, Oakville Hydro, Woodstock Hydro, the Nova Scotia Utilities Review Board and the Alberta Market Surveillance Administrator, and more broadly in the energy sector Pelino has worked on a number of M&A and capital raising assignments for renewable energy companies.

Prior to joining MPA in 2005, Pelino was Chief of Staff to the Ontario Minister of Energy from 2003 to 2005. During that time, he assisted in significant restructuring of the Ontario electricity sector, including the drafting and implementation of new legislation, the creation of the Ontario Power Authority, and significant procurements of new electricity generation capacity for the province.

Previously, Pelino spent more than 10 years in management, policy and communications consulting in Canada and the United States, advising clients across a wide range of sectors, including energy, transportation, telecommunications, and healthcare.

Pelino holds a B.A. and an L.Lb., both from the University of Toronto.

Brent Walker

Brent Walker is a Managing Director and co-founder of MPA. In this role he is responsible for transaction origination and execution, financial advisory and capital raising activities across a wide spectrum of industry segments, including energy, technology, government and quasi-government entities and a variety of other commercial sectors.

Utility clients have included BC Hydro, Altagas Utilities, Crown Investments Corporation, Hydro One, Market Surveillance Administrator of Alberta, the Nova Scotia Utilities Review Board, the Ontario Ministry of Energy and many others.

Prior to founding MPA in 2004, Brent spent over 10 years in the investment banking and financial industry. From 1996 to 2004, he was a managing director in Scotia Capital's mergers and acquisitions department, where he was the most senior M&A banker in a number of sectors including power and infrastructure, pipelines, energy midstream and real estate. During this period, he worked on the sale of the Province of Nova Scotia's interest in Nova Scotia Resources Limited, the acquisition of Aquila by Fortis, the proposed privatization of NALCOR and Enmax, and many other utility assignments.

Brent started his investment banking career at Lancaster Financial, Canada's foremost independent M&A boutique which was acquired by TD Bank in 1994.

Brent holds a B.Sc. from Dalhousie University and an MBA from McMaster University.

Benjamin Kinder

Benjamin Kinder is a vice president at MPA. He is responsible for client engagement, transaction design and execution, client development and overall delivery of service.

Prior to joining MPA, Benjamin spent two years in Scotia Capital's investment banking and equity capital markets divisions. While there, he focused on the communications, media and technology sectors, advising clients on mergers and acquisitions, and capital markets transactions.

Benjamin has experience in a number of industry segments including power and infrastructure, regulated utilities, basic materials, technology, media, telecommunications, non-profits and quasi-government entities.

His work has included mergers and acquisitions advisory, restructuring, private capital raising for early and mid-stage companies, expert advisory work for regulators, and strategic advice to the clients in the face of substantial change.

Benjamin holds a Bachelor of Business Administration (B.B.A.) from York University's Schulich School of Business, and a Master of Arts (M.A. Cantab.) from the University of Cambridge.

Appendix B Description of Model

MPA has constructed a financial model on Manitoba Hydro's electrical operations ("MH") in order to address the scope of work put to MPA by the PUB under the NFAT. MPA relied upon the NFAT, the appendices thereto, and numerous discussions and correspondence with MH management and employees on the matter of MH operations, and economic, and financial conditions. MPA relied especially on Appendix 11.4 to the NFAT (Pro Forma Financial Statements), Appendix 11.2 (Projected Escalation, Interest and Exchange Rates), and Appendix 9.3 (Economic Evaluation Documentation). The model runs through year 2062 (inclusive) given that this was the time horizon selected by MH in the presentation of pro forma financial statements in Appendix 11.4, and is denominated in nominal Canadian dollars. All inputs received by MPA and not already presented in nominal Canadian dollars were converted accordingly such that the basis of comparison between all financial data was consistent.

MPA received SPLASH (Simulation Program for Long-term Analysis of System Hydraulics) output from MH with respect to the development plans considered under the NFAT. The SPLASH data detailed forecast adjusted load in the province of Manitoba, and firm and opportunity export demand, on a GWh basis, and the supply mix necessary to balance load and export demand. Crucially, this data was provided for ninety-nine years of hydrological history (1912-2010 inclusive), on a month by month basis, and modelled out to 2048 (or, 2049 as the case may be) given the supply mix and anticipated load and export demand for a given forecast year. Receiving actual, historical hydrological data modelled for a future, anticipated supply mix was crucial to MPA's efforts to model hydrological risk in the system and adequately address the scope of work put to MPA by the PUB.

By hydrological risk in the system is meant the effect of actual annual hydrology on the domestic revenue requirement, domestic revenue, net income, equity ratio, interest coverage ratio and other measures of MH financial risk and performance. The use of average hydrology by the model underlying Appendix 11.4 is instructive in understanding the system over a relatively longer period of time (Appendix 11.4 runs through 2062, inclusive). However, averages mask underlying variability (with respect to hydrology, both flood and drought), and thus MH's ability to realize opportunity export revenue in the event of a drought, or prolonged drought.

SPLASH data included monthly energies at generation for hydro, thermal and import energy (both on and off-peak) to produce total supply, balanced against adjusted provincial load, and firm and opportunity export demand (all on and off-peak). MPA summed all monthly data to annual totals and produced a data set for every variable modelling a given hydrological history (vertical columns) for a future model year (horizontal rows).

Further, MPA created chained data sets necessary to calculate net flow related revenue, including opportunity export revenue (both on and off-peak), and the cost of hydro, thermal and import energy (both on and off-peak). Chained data is created in a series of matrices, one for each variable under each

scenario, and under each development plan, and reflects the historical, physical hydrology experienced by MH through the years 1912-2010. Chained data sets follow a set pattern of down one row and right one column from unchained data, so that the actual hydrology that existed in 1960 (as an example year) may be followed through the model as if that hydrology were experienced in model year 2015 (model year start date). Model year 2016 would then reflect the actual hydrological conditions experienced by MH in the year 1961 given a hydrological start date of 1960. Any hydrological year on record may be selected, and any development plan, under any scenario, may then be considered.

MPA matched the SPLASH data with the development plans detailed in Appendix 11.4 of the NFAT, eliminating plans for which pro forma financial statement data was not provided. MPA extracted chained, opportunity export revenue for every given hydrological regime and model year, allowing for the determination of actual, annual opportunity export revenue, calculated for a given supply mix that MH anticipates to eventuate in a given year. This information and extraction (from SPLASH), and application (to Appendix 11.4) allowed MPA to produce a set of financial statements (income statement, balance sheet and cash flow statement) for every development plan modelled under Appendix 11.4 under all scenarios, and under all previous hydrology regimes.

By way of example, the Preferred Development Plan may be evaluated under twenty-seven different combinations of reference, high and low economic, energy and capital scenarios (3x3x3=27). Further, ninety-nine different historical hydrological patterns (the SPLASH data referenced above) may be run through any one of these twenty-seven possible scenarios to produce 2,673 (3x3x3x99) possible outcomes for the Preferred Development Plan alone. This process may be repeated for any development plan for which information was provided under Appendix 11.4 to the NFAT.

MPA embedded significant functionality into the model to allow for a thorough financial analysis. Such functionality includes selecting hydrological history, economic, energy and capital scenarios, and a development plan; rate increases by implied domestic revenue requirement or percent increase per year; unanticipated capital cost expenditures; term structure on new debt issued, deemed equity component of capital structure and deemed return on equity etc.

In reaching our conclusions contained in this report, MPA has run the All Gas and Preferred Development plans, and Plans 4, 6 and 12 under the 2012 reference Manitoba load for all 99 years of hydrological history through year 2062 (at reference economics, energy and capital, for 495 total runs).

The All Gas and Preferred Development Plans were further run at high and low 2012 Manitoba load for all 99 years of hydrological history through year 2062 (at reference economics, energy and capital, for 396 total runs).

The Preferred Development Plan was further run at 4x 2013 DSM and 1x 2012 DSM (both at 2013 reference Manitoba load) for all 99 years of hydrological history through year 2062 (at reference economics, energy and capital, for 198 total runs).

The All Gas and Preferred Development plans, and Plans 4,6 and 12, were run for 21 different years of hydrological history, for every combination of reference, high and low economics, energy and capital costs, for a total of 546 runs per development plan, or 2730 total runs.

For example, Development Plan 4 was run for 21 different years of hydrological history under 26 different combinations of reference, high and low economics, energy and capital costs (the ref-ref-ref scenario detailed above is excluded here, where all 99 years of hydrological history were considered).

In total, MPA performed 3,819 different runs of the financial model. Given that a full reckoning of the All Gas and Preferred Development Plans, and Plans 4,6 and 12 considered under only 2012 reference load conditions would have required 13,365 total runs of the model, MPA used professional judgment in the determination of what hydrological years to consider, under a given economics, energy and capital cost scenario and under a given development plan. While Appendix 11.4 to the NFAT considered plans 2,7 and 13, MPA did not further consider those development plans given the base similarity between those plans and others considered by MPA.

The twenty-one years of hydrology considered by MPA are a sampling of the ninety-nine years of actual hydrological history, and include the years 1912, 1916, 1920, 1928, 1932, 1936, 1940, 1948, 1952, 1956, 1960, 1968, 1972, 1976, 1980, 1988, 1992, 1996, 2000, 2008 and 2010.

All decades of hydrological history were included by MPA in our analysis of MH, and include both drought and flood years.

The financial model, as constructed above, formed the basis for our financial conclusions reached in this report.

Appendix C

Tables of Results of the Present Value of Domestic Revenue

PV of Domestic Revenue
Maximum, Minimum, Average, Standard Deviation and MH Assigned Probability
All Economic, Energy and Capital Scenarios
All Gas
NPV @ 6.00%
($ in millions)

		Energy and Capital								
		RR	RH	RL	HR	HH	HL	LR	LH	LL
High Economics	Maximum	$56,907	$57,989	$55,996	$58,177	$58,815	$57,431	$55,503	$56,546	$54,613
	Minimum	$51,485	$53,145	$51,100	$52,283	$53,360	$51,374	$52,253	$53,444	$51,346
	Average	$54,025	$55,133	$53,085	$54,996	$56,139	$54,150	$53,620	$54,748	$52,693
	Standard Deviation	$1,284	$1,233	$1,225	$1,762	$1,707	$1,768	$772	$738	$732
	MH assigned probability	9.6%	5.8%	3.9%	2.6%	1.6%	1.1%	5.3%	3.2%	2.1%
Reference Economics	Maximum	$45,530	$46,121	$44,736	$46,076	$46,726	$45,483	$44,922	$45,742	$44,289
	Minimum	$42,312	$43,171	$41,692	$41,723	$42,777	$41,154	$42,856	$43,559	$42,381
	Average	$43,791	$44,515	$43,182	$44,107	$44,842	$43,553	$43,695	$44,453	$43,116
	Standard Deviation	$786	$760	$762	$1,163	$1,090	$1,168	$465	$491	$451
	MH assigned probability	13.8%	8.3%	5.5%	3.8%	2.3%	1.5%	7.5%	4.5%	3.0%
Low Economics	Maximum	$36,730	$37,069	$36,394	$37,176	$37,752	$36,892	$36,242	$36,711	$35,914
	Minimum	$35,104	$35,630	$34,833	$34,577	$34,811	$34,378	$35,233	$35,632	$34,932
	Average	$35,806	$36,283	$35,470	$35,981	$36,332	$35,633	$35,717	$36,182	$35,351
	Standard Deviation	$401	$406	$398	$706	$745	$672	$291	$351	$264
	MH assigned probability	4.1%	2.5%	1.7%	1.1%	0.7%	0.5%	2.3%	1.4%	0.9%

PV of Domestic Revenue
Maximum, Minimum, Average, Standard Deviation and MH Assigned Probability
All Economic, Energy and Capital Scenarios
All Gas
NPV @ 10.00%
($ in millions)

		Energy and Capital								
		RR	**RH**	**RL**	**HR**	**HH**	**HL**	**LR**	**LH**	**LL**
High Economics	Maximum	$28,677	$29,091	$28,358	$28,978	$29,349	$28,719	$28,677	$28,906	$28,193
	Minimum	$26,745	$27,113	$26,362	$26,118	$26,472	$25,769	$27,376	$27,742	$27,065
	Average	$27,606	$28,044	$27,310	$27,446	$27,853	$27,161	$27,884	$28,251	$27,546
	Standard Deviation	$528	$530	$537	$845	$873	$833	$341	$302	$284
	MH assigned probability	9.6%	5.8%	3.9%	2.6%	1.6%	1.1%	5.3%	3.2%	2.1%
Reference Economics	Maximum	$24,278	$24,427	$24,031	$24,393	$24,566	$24,200	$24,110	$24,382	$23,899
	Minimum	$23,040	$23,325	$22,852	$22,369	$22,756	$22,203	$23,420	$23,657	$23,266
	Average	$23,623	$23,868	$23,425	$23,441	$23,674	$23,265	$23,724	$23,988	$23,534
	Standard Deviation	$321	$317	$322	$581	$576	$591	$185	$193	$180
	MH assigned probability	13.8%	8.3%	5.5%	3.8%	2.3%	1.5%	7.5%	4.5%	3.0%
Low Economics	Maximum	$20,292	$20,394	$20,200	$20,390	$20,557	$20,313	$20,201	$20,331	$20,083
	Minimum	$19,781	$19,954	$19,701	$19,287	$19,374	$19,214	$19,893	$20,021	$19,808
	Average	$20,020	$20,163	$19,922	$19,965	$20,070	$19,861	$20,039	$20,175	$19,931
	Standard Deviation	$130	$124	$135	$310	$321	$302	$87	$98	$78
	MH assigned probability	4.1%	2.5%	1.7%	1.1%	0.7%	0.5%	2.3%	1.4%	0.9%

PV of Domestic Revenue
Maximum, Minimum, Average, Standard Deviation and MH Assigned Probability
All Economic, Energy and Capital Scenarios
Development Plan 4
NPV @ 6.00%
($ in millions)

		Energy and Capital								
		RR	**RH**	**RL**	**HR**	**HH**	**HL**	**LR**	**LH**	**LL**
High Economics	Maximum	$55,098	$56,837	$54,109	$54,795	$56,399	$52,670	$56,351	$58,088	$55,194
	Minimum	$49,822	$51,713	$48,829	$46,275	$48,965	$44,491	$52,956	$54,681	$51,913
	Average	$52,474	$54,067	$51,355	$51,245	$53,053	$50,005	$54,324	$56,053	$53,078
	Standard Deviation	$1,403	$1,313	$1,392	$2,096	$2,028	$2,140	$812	$790	$802
	MH assigned probability	9.6%	5.8%	3.9%	2.6%	1.6%	1.1%	5.3%	3.2%	2.1%
Reference Economics	Maximum	$44,591	$45,625	$43,764	$43,962	$45,003	$42,990	$45,232	$46,441	$44,568
	Minimum	$41,625	$42,458	$40,729	$39,241	$40,441	$38,635	$43,336	$44,499	$42,624
	Average	$42,878	$43,916	$42,135	$41,868	$42,909	$41,081	$44,192	$45,298	$43,411
	Standard Deviation	$733	$816	$757	$1,271	$1,218	$1,145	$475	$486	$468
	MH assigned probability	13.8%	8.3%	5.5%	3.8%	2.3%	1.5%	7.5%	4.5%	3.0%
Low Economics	Maximum	$35,713	$36,253	$35,504	$35,331	$35,942	$35,128	$36,456	$36,815	$35,678
	Minimum	$34,134	$34,736	$33,898	$32,574	$33,654	$32,550	$35,243	$35,673	$34,765
	Average	$34,947	$35,420	$34,458	$34,165	$34,757	$33,763	$35,706	$36,327	$35,202
	Standard Deviation	$396	$450	$408	$699	$652	$707	$357	$350	$301
	MH assigned probability	4.1%	2.5%	1.7%	1.1%	0.7%	0.5%	2.3%	1.4%	0.9%

PV of Domestic Revenue
Maximum, Minimum, Average, Standard Deviation and MH Assigned Probability
All Economic, Energy and Capital Scenarios
Development Plan 4
NPV @ 10.00%
($ in millions)

		Energy and Capital								
		RR	RH	RL	HR	HH	HL	LR	LH	LL
High Economics	Maximum	$28,540	$29,327	$28,114	$28,195	$28,918	$27,524	$29,274	$29,935	$28,803
	Minimum	$26,380	$27,274	$26,164	$24,752	$25,515	$24,219	$28,092	$28,681	$27,578
	Average	$27,628	$28,273	$27,175	$26,718	$27,392	$26,257	$28,608	$29,234	$28,140
	Standard Deviation	$542	$562	$521	$884	$889	$864	$308	$318	$295
	MH assigned probability	9.6%	5.8%	3.9%	2.6%	1.6%	1.1%	5.3%	3.2%	2.1%
Reference Economics	Maximum	$24,089	$24,417	$23,825	$23,812	$24,165	$23,452	$24,321	$24,736	$24,129
	Minimum	$23,051	$23,258	$22,649	$21,823	$22,174	$21,363	$23,717	$24,146	$23,485
	Average	$23,476	$23,827	$23,199	$22,810	$23,229	$22,532	$24,017	$24,384	$23,746
	Standard Deviation	$291	$315	$321	$613	$588	$590	$184	$173	$179
	MH assigned probability	13.8%	8.3%	5.5%	3.8%	2.3%	1.5%	7.5%	4.5%	3.0%
Low Economics	Maximum	$20,034	$20,177	$19,990	$19,877	$20,078	$19,821	$20,269	$20,378	$20,066
	Minimum	$19,497	$19,693	$19,411	$18,737	$18,945	$18,546	$19,941	$20,061	$19,780
	Average	$19,795	$19,935	$19,626	$19,401	$19,603	$19,254	$20,064	$20,238	$19,913
	Standard Deviation	$143	$150	$160	$336	$310	$342	$102	$93	$96
	MH assigned probability	4.1%	2.5%	1.7%	1.1%	0.7%	0.5%	2.3%	1.4%	0.9%

PV of Domestic Revenue
Maximum, Minimum, Average, Standard Deviation and MH Assigned Probability
All Economic, Energy and Capital Scenarios
Development Plan 6
NPV @ 6.00%
($ in millions)

		Energy and Capital								
		RR	**RH**	**RL**	**HR**	**HH**	**HL**	**LR**	**LH**	**LL**
High Economics	Maximum	$55,404	$57,432	$54,431	$54,721	$56,142	$53,104	$58,484	$58,390	$55,712
	Minimum	$50,590	$52,381	$49,375	$47,373	$49,295	$45,445	$53,577	$55,109	$52,346
	Average	$52,975	$54,588	$51,879	$51,838	$53,336	$50,587	$54,969	$56,469	$53,616
	Standard Deviation	$1,336	$1,309	$1,442	$2,016	$1,982	$2,060	$1,087	$830	$817
	MH assigned probability	9.6%	5.8%	3.9%	2.6%	1.6%	1.1%	5.3%	3.2%	2.1%
Reference Economics	Maximum	$44,919	$46,090	$44,435	$44,883	$45,085	$43,233	$45,748	$46,953	$44,925
	Minimum	$41,890	$42,964	$41,126	$39,668	$41,212	$39,241	$43,754	$44,793	$43,034
	Average	$43,301	$44,312	$42,511	$42,317	$43,355	$41,497	$44,585	$45,724	$43,851
	Standard Deviation	$822	$809	$807	$1,308	$1,159	$1,195	$493	$567	$456
	MH assigned probability	13.8%	8.3%	5.5%	3.8%	2.3%	1.5%	7.5%	4.5%	3.0%
Low Economics	Maximum	$36,034	$36,444	$35,644	$35,336	$36,004	$35,193	$36,456	$37,056	$36,081
	Minimum	$34,472	$34,870	$33,898	$33,214	$33,654	$32,550	$35,373	$35,947	$35,061
	Average	$35,135	$35,679	$34,685	$34,397	$34,967	$33,977	$35,903	$36,576	$35,448
	Standard Deviation	$436	$454	$451	$676	$661	$737	$327	$353	$297
	MH assigned probability	4.1%	2.5%	1.7%	1.1%	0.7%	0.5%	2.3%	1.4%	0.9%

PV of Domestic Revenue
Maximum, Minimum, Average, Standard Deviation and MH Assigned Probability
All Economic, Energy and Capital Scenarios
Development Plan 6
NPV @ 10.00%
($ in millions)

		Energy and Capital								
		RR	RH	RL	HR	HH	HL	LR	LH	LL
High Economics	Maximum	$28,818	$29,523	$28,319	$28,282	$28,727	$27,718	$30,633	$30,220	$29,069
	Minimum	$26,757	$27,433	$26,281	$25,056	$25,773	$24,506	$28,326	$28,961	$27,914
	Average	$27,861	$28,525	$27,399	$26,972	$27,636	$26,496	$28,926	$29,509	$28,396
	Standard Deviation	$540	$547	$526	$861	$843	$856	$502	$322	$298
	MH assigned probability	9.6%	5.8%	3.9%	2.6%	1.6%	1.1%	5.3%	3.2%	2.1%
Reference Economics	Maximum	$24,166	$24,595	$24,058	$24,143	$24,179	$23,560	$24,530	$24,912	$24,240
	Minimum	$23,126	$23,424	$22,717	$21,938	$22,385	$21,799	$23,855	$24,246	$23,646
	Average	$23,633	$24,013	$23,345	$22,991	$23,415	$22,693	$24,169	$24,557	$23,922
	Standard Deviation	$307	$304	$336	$634	$561	$580	$181	$192	$173
	MH assigned probability	13.8%	8.3%	5.5%	3.8%	2.3%	1.5%	7.5%	4.5%	3.0%
Low Economics	Maximum	$20,137	$20,252	$20,020	$19,874	$20,089	$19,833	$20,269	$20,432	$20,180
	Minimum	$19,649	$19,755	$19,411	$18,870	$19,040	$18,735	$19,971	$20,130	$19,879
	Average	$19,859	$20,029	$19,704	$19,479	$19,676	$19,332	$20,122	$20,310	$19,994
	Standard Deviation	$149	$143	$171	$324	$315	$353	$92	$90	$86
	MH assigned probability	4.1%	2.5%	1.7%	1.1%	0.7%	0.5%	2.3%	1.4%	0.9%

PV of Domestic Revenue
Maximum, Minimum, Average, Standard Deviation and MH Assigned Probability
All Economic, Energy and Capital Scenarios
Development Plan 12
NPV @ 6.00%
($ in millions)

		Energy and Capital								
		RR	**RH**	**RL**	**HR**	**HH**	**HL**	**LR**	**LH**	**LL**
High Economics	Maximum	$57,081	$59,474	$55,311	$55,565	$57,430	$53,814	$61,054	$62,606	$58,357
	Minimum	$52,434	$54,113	$50,946	$48,504	$50,384	$46,839	$54,269	$58,924	$55,188
	Average	$54,634	$56,612	$53,208	$52,125	$54,235	$50,463	$58,032	$60,575	$56,571
	Standard Deviation	$1,310	$1,438	$1,297	$2,067	$1,905	$2,056	$1,268	$948	$798
	MH assigned probability	9.6%	5.8%	3.9%	2.6%	1.6%	1.1%	5.3%	3.2%	2.1%
Reference Economics	Maximum	$46,557	$47,630	$45,605	$44,883	$46,191	$44,024	$48,879	$50,445	$47,630
	Minimum	$42,873	$44,222	$42,130	$39,944	$41,472	$39,161	$46,176	$47,847	$45,065
	Average	$44,727	$46,066	$43,699	$42,409	$43,889	$41,366	$47,375	$48,994	$46,174
	Standard Deviation	$1,100	$1,087	$1,092	$1,405	$1,481	$1,402	$785	$699	$721
	MH assigned probability	13.8%	8.3%	5.5%	3.8%	2.3%	1.5%	7.5%	4.5%	3.0%
Low Economics	Maximum	$36,197	$37,141	$36,053	$35,467	$36,053	$34,870	$37,326	$37,640	$36,970
	Minimum	$34,693	$35,371	$34,064	$33,124	$33,696	$32,410	$36,275	$37,127	$35,731
	Average	$35,526	$36,275	$35,044	$34,182	$34,852	$33,504	$37,008	$37,539	$36,507
	Standard Deviation	$489	$504	$560	$800	$724	$751	$294	$152	$332
	MH assigned probability	4.1%	2.5%	1.7%	1.1%	0.7%	0.5%	2.3%	1.4%	0.9%

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PV of Domestic Revenue
Maximum, Minimum, Average, Standard Deviation and MH Assigned Probability
All Economic, Energy and Capital Scenarios
Development Plan 12
NPV @ 10.00%
($ in millions)

		Energy and Capital								
		RR	**RH**	**RL**	**HR**	**HH**	**HL**	**LR**	**LH**	**LL**
High Economics	Maximum	$29,951	$31,003	$29,323	$29,156	$30,093	$28,478	$31,419	$32,053	$30,534
	Minimum	$27,926	$28,762	$27,259	$25,875	$26,718	$25,349	$27,910	$30,850	$29,291
	Average	$28,996	$29,844	$28,363	$27,613	$28,507	$26,944	$30,406	$31,425	$29,874
	Standard Deviation	$595	$619	$598	$924	$996	$920	$680	$349	$338
	MH assigned probability	9.6%	5.8%	3.9%	2.6%	1.6%	1.1%	5.3%	3.2%	2.1%
Reference Economics	Maximum	$24,876	$25,189	$24,567	$24,329	$24,743	$24,107	$25,534	$25,921	$25,189
	Minimum	$23,631	$24,124	$23,449	$22,242	$22,717	$21,882	$24,774	$25,269	$24,441
	Average	$24,285	$24,710	$23,924	$23,274	$23,840	$22,900	$25,122	$25,562	$24,773
	Standard Deviation	$377	$336	$387	$657	$634	$672	$216	$178	$214
	MH assigned probability	13.8%	8.3%	5.5%	3.8%	2.3%	1.5%	7.5%	4.5%	3.0%
Low Economics	Maximum	$20,220	$20,469	$20,175	$19,999	$20,175	$19,827	$20,511	$20,587	$20,425
	Minimum	$19,772	$19,979	$19,557	$18,811	$18,976	$18,579	$20,249	$20,456	$20,092
	Average	$20,019	$20,232	$19,858	$19,517	$19,740	$19,282	$20,433	$20,562	$20,308
	Standard Deviation	$148	$144	$191	$345	$326	$341	$72	$37	$88
	MH assigned probability	4.1%	2.5%	1.7%	1.1%	0.7%	0.5%	2.3%	1.4%	0.9%

PV of Domestic Revenue
Maximum, Minimum, Average, Standard Deviation and MH Assigned Probability
All Economic, Energy and Capital Scenarios
Preferred Development Plan
NPV @ 6.00%
($ in millions)

		Energy and Capital								
		RR	**RH**	**RL**	**HR**	**HH**	**HL**	**LR**	**LH**	**LL**
High Economics	Maximum	$57,536	$60,272	$55,649	$55,164	$57,601	$53,339	$60,135	$63,894	$59,089
	Minimum	$51,715	$53,975	$49,929	$47,050	$49,389	$45,396	$55,503	$59,927	$55,227
	Average	$54,196	$56,807	$52,377	$51,167	$53,343	$49,305	$58,508	$61,578	$56,828
	Standard Deviation	$1,549	$1,866	$1,491	$2,371	$2,343	$2,165	$1,105	$1,094	$950
	MH assigned probability	9.6%	5.8%	3.9%	2.6%	1.6%	1.1%	5.3%	3.2%	2.1%
Reference Economics	Maximum	$45,851	$47,672	$44,735	$44,488	$45,710	$43,420	$47,919	$50,041	$47,637
	Minimum	$42,711	$44,064	$41,911	$40,190	$41,653	$38,763	$45,819	$47,801	$44,800
	Average	$44,230	$45,652	$43,088	$41,991	$43,454	$40,927	$47,037	$48,682	$45,737
	Standard Deviation	$1,018	$1,086	$917	$1,383	$1,281	$1,412	$658	$591	$754
	MH assigned probability	13.8%	8.3%	5.5%	3.8%	2.3%	1.5%	7.5%	4.5%	3.0%
Low Economics	Maximum	$36,086	$36,576	$35,595	$35,120	$35,580	$34,904	$37,179	$37,648	$36,576
	Minimum	$34,487	$35,150	$33,993	$32,442	$33,280	$32,442	$36,214	$36,729	$35,511
	Average	$35,210	$35,883	$34,677	$33,854	$34,459	$33,388	$36,691	$37,270	$36,093
	Standard Deviation	$494	$470	$580	$724	$710	$790	$248	$213	$321
	MH assigned probability	4.1%	2.5%	1.7%	1.1%	0.7%	0.5%	2.3%	1.4%	0.9%

PV of Domestic Revenue
Maximum, Minimum, Average, Standard Deviation and MH Assigned Probability
All Economic, Energy and Capital Scenarios
Preferred Development Plan
NPV @ 10.00%
($ in millions)

		Energy and Capital								
		RR	**RH**	**RL**	**HR**	**HH**	**HL**	**LR**	**LH**	**LL**
High Economics	Maximum	$30,286	$31,418	$29,675	$29,573	$30,319	$28,656	$31,418	$32,391	$30,717
	Minimum	$28,274	$29,317	$27,636	$26,641	$27,183	$25,628	$28,505	$31,091	$29,594
	Average	$29,123	$30,124	$28,477	$27,790	$28,674	$26,983	$30,626	$31,721	$30,099
	Standard Deviation	$596	$638	$575	$957	$941	$969	$585	$383	$324
	MH assigned probability	9.6%	5.8%	3.9%	2.6%	1.6%	1.1%	5.3%	3.2%	2.1%
Reference Economics	Maximum	$24,657	$25,215	$24,292	$24,290	$24,599	$23,923	$25,304	$25,832	$25,205
	Minimum	$23,657	$24,118	$23,229	$22,022	$22,625	$21,673	$24,661	$25,239	$24,364
	Average	$24,148	$24,605	$23,754	$23,268	$23,771	$22,873	$25,037	$25,490	$24,654
	Standard Deviation	$333	$335	$328	$611	$564	$640	$186	$156	$222
	MH assigned probability	13.8%	8.3%	5.5%	3.8%	2.3%	1.5%	7.5%	4.5%	3.0%
Low Economics	Maximum	$20,197	$20,324	$20,048	$19,913	$20,043	$19,849	$20,488	$20,603	$20,332
	Minimum	$19,740	$19,944	$19,438	$18,599	$18,867	$18,599	$20,230	$20,375	$20,049
	Average	$19,937	$20,135	$19,754	$19,434	$19,638	$19,269	$20,367	$20,511	$20,207
	Standard Deviation	$154	$137	$198	$331	$320	$349	$64	$53	$85
	MH assigned probability	4.1%	2.5%	1.7%	1.1%	0.7%	0.5%	2.3%	1.4%	0.9%